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

AND IN THE MATTER OF an Application by Grimsby 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 January 1, 2012.

GRIMSBY POWER INC

2012 ELECTRICITY DISTRIBUTION RATE APPLICATION

FILED: August 16, 2011

Applicant
Grimsby Power Inc.
231 Roberts Road,
Grimsby, ON
L3M 5N2

Attention: Mr. Doug Curtiss, Chief Executive Officer

Telephone: 905-945-5437
Fax: 905-945-9933
E-mail: dougc@grimsbypower.com

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

AND IN THE MATTER OF an Application by Grimsby 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 January 1, 2012.

Title of Proceeding:	An Application by Grimsby Power Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective January 1, 2012.
Applicants Name:	Grimsby Power Inc.
Applicants Address:	231 Roberts Road Grimsby, ON L3M 5N2

Applicants Contacts:

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Exhibit 1 Administration

APPLICATION

Introduction

The Applicant is Grimsby Power Inc. The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Grimsby, ON. The Applicant carries on the business of distributing electricity within the Town of Grimsby.

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the Ontario Energy Board Act, 1998 ("the OEB Act") for approval of its proposed distribution rates and other charges, effective January 1, 2012. A list of requested approvals is set out below.

Except where specifically identified in the Application, the Applicant followed the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, update issued June 28, 2010 (the "Filing Requirements") in order to prepare this application.

In accordance with the Board letter of March 15, 2011 with respect to the "Use of Modified IFRS as a Basis for Filing Cost of Service Applications for 2012 Rates" Grimsby Power Inc. has prepared this Application under the Boards Modified IFRS (MIFRS) approach.

Proposed Distribution Rates and Other Charges

The Schedule of Proposed Tariff of Rates and Charges in this Application is set out in Table 1.1 below and in Exhibit 8. The material being filed in support of this Application sets out Grimsby Power Inc.'s approach to its distribution rates and charges.

Proposed Effective Date of Rate Order

The Applicant requests that the OEB make its Rate Order effective January 1, 2012 in accordance with the Filing Requirements.

In the event that the OEB is unable to provide a Decision and Order in the Application for implementation by the Applicant as of January 1, 2012, the Applicant requests that the OEB issue an interim Order approving the proposed distribution rates and other charges, effective January 1, 2012 which may be subject to adjustment based on its final Decision and Order.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

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

The proposed rates, as set out in Table 1.1, for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles.

The proposed and adjusted rates are necessary to ensure Grimsby Power Inc. has sufficient funds to meet its capital expenditure obligations, fund OM&A expenses, and provide for a reasonable Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILS");

There are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures. Bill impacts for Grimsby Power Inc.'s average usage customers in the residential, GS<50kW, and GS>50kW are below 10%. It should be noted the smart meter rate rider listed in Table 1.1 is significant and contains both the smart meter rate rider and the stranded meter rate rider.

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

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

Relief Sought

The Applicant applies for an Order or Orders approving the proposed distribution rates and charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective January 1, 2012.

In the event that the OEB is unable to provide a Decision and Order in the Application for implementation by the Applicant as of January 1, 2012, the Applicant requests that the OEB issue an interim Order approving the proposed distribution rates and other charges, effective January 1, 2012 which may be subject to adjustment based on its final Decision and Order.

The Applicant seeks approval for cost recovery of smart meter project costs including the recovery of stranded meter costs in accordance with OEB document G-2008-0002 the "Smart Meter Funding and Cost Recovery" guideline dated October 22, 2008.

The Applicant seeks approval of its Basic Green Energy Plan as part of this Application in accordance with the Deemed Conditions of License as reported by the OEB in its Distribution System Planning Guidelines G-2009-0087, issued June 16, 2009. The Applicants Basic Green Energy Plan has been prepared in accordance with the OEB's Filing Requirements as reported in EB-2009-0397 – Distribution System Plans under the Green Energy Act issued on December 18, 2009.

Form of Hearing Requested

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

DATED at Grimsby, Ontario, this 16th day of August 2011.

All of which is respectfully submitted,

Grimsby Power Inc.

Doug Curtiss

Chief Executive Officer

Table 1.1 Schedule of Proposed Rates and Charges

Residential		
Monthly Service Charge	$	18.47
Distribution Volumetric Rate	$/kwh	0.0105
Low Voltage Rider	$/kwh	0.0007
LRAM and SSM Rate Rider	$/kwh	0.0003
Smart Meter Rate Rider	$	4.8458
Deferral and Variance Account Rider	$/kwh	(0.0014)
Retail Transmission Rate - Network	$/kwh	0.0066
Retail Transmission Rate – Connection	$/kwh	0.0054
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.0250
General Service < 50 kW		
Monthly Service Charge	$	31.62

Distribution Volumetric Rate	$/kwh	0.0124
Low Voltage Rider	$/kwh	0.0006
LRAM and SSM Rate Rider	$/kwh	0.0002
Smart Meter Rate Rider	$	4.8458
Deferral and Variance Account Rider	$/kwh	(0.0013)
Retail Transmission Rate - Network	$/kwh	0.0061
Retail Transmission Rate – Connection	$/kwh	0.0047
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.0250
General Service > 50 kW		
Monthly Service Charge	$	204.19
Distribution Volumetric Rate	$/kW	1.7071
Low Voltage Rider	$/kW	0.2603
LRAM and SSM Rate Rider	$/kW	0.0921
Smart Meter Rate Rider	$	4.8458
Deferral and Variance Account Rider	$/kW	(0.4621)

Retail Transmission Rate - Network	$/kW	2.4546
Retail Transmission Rate – Connection	$/kW	1.9125
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.0250
Street Lighting		
Monthly Service Charge	per month	1.52
Distribution Volumetric Rate	$/kW	7.4364
Low Voltage Rider	$/kW	0.2012
LRAM and SSM Rate Rider	$/kW	0.0000
Deferral and Variance Account Rider	$/kW	(1.0081)
Retail Transmission Rate - Network	$/kW	1.8512
Retail Transmission Rate – Connection	$/kW	1.4785
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.2500

Unmetered Scattered Load		
Monthly Service Charge	per month	16.78
Distribution Volumetric Rate	$/kwh	0.0130
Low Voltage Rider	$/kwh	0.0006
LRAM and SSM Rate Rider	$/kwh	0.0000
Deferral and Variance Account Rider	$/kwh	(0.0015)
Retail Transmission Rate - Network	$/kwh	0.0061
Retail Transmission Rate – Connection	$/kwh	0.0047
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.2500

Item Description (Rate Code)	**Calculation Basis**	**Rate ($)**
Arrears Certificate (1)	Standard	15.00
Statement of Account (2)	Standard	15.00
Pulling Post Dated Cheques (3)	Standard	15.00

Duplicate Invoices for Previous Billing (4)	Standard	15.00
Easement Letter (5)	Standard	15.00
Account History (6)	Standard	15.00
Credit Reference/Credit Check (Plus Credit Agency Costs) (7)	Standard	15.00
Returned Cheque Charge (8)	Standard	15.00
Charge to Certify Cheque (9)	Standard	15.00
Legal Letter Charge (10)	Standard	15.00
Account Set Up Charge/Change of Occupancy Charge (Plus Credit Agency Costs if Applicable) (11)	Standard	30.00
Special meter reads (12)	Standard	30.00
Meter Dispute Chare plus Meter Measurement Canada Fees (13)	Standard	30.00
Interval Meter interogation (14)	Standard	20.00
Late Payment - per Month (15)	%	1.50
Late Payment - per Month (16)	%	19.56
Collection of Account Charge - No Disconnection (17)	Standard	30.00

Collection of Account Charge - No Disconnection - After Regular Hours (18)	Standard	165.00
Disconnect/Reconnect at Meter - During Regular Hours (19)	Standard	65.00
Disconnect/Reconnect at Meter - After Regular Hours (21)	Standard	185.00
Disconnect/Reconnect at Pole - During Regular Hours (20)	Standard	185.00
Disconnect/Reconnect at Pole - After Regular Hours (22)	Standard	415.00
Service call - Customer Owned Equipment (25)	Standard	30.00
Service Call - After Regular Hours (26)	Standard	165.00
Install/Remove Load Control Device - During Regular Hours (27)	Standard	65.00
Install/Remove Load Control Device - After Regular Hours (28)	Standard	185.00
Temporary Service Install & Remove - Overhead - No Transformer (29)	Standard	500.00
Temporary Service Install &	Standard	300.00

Remove - Underground - No Transformer (30)		
Temporary Service Install & Remove - Overhead - with Transformer (31)	Standard	1,000.00
Specific Charge for Access to the Power Poles $/Pole/Year (32)	Standard	22.35

Loss Factors	
Supply Facilities Loss Factor	1.0131
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0390
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	0.0000
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0287
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	0.0000
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0526
Total Loss Factor - Secondary Metered Customer > 5,000 kW	0.0000
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0421

Total Loss Factor - Primary Metered Customer > 5,000 kW	0.0000

PUBLICATION OF NOTICES

Grimsby Power Inc. intends to publish all required notices in the Grimsby Lincoln News a local newspaper owned by Metroland Media Group Ltd. The Grimsby Lincoln news is distributed as an unpaid circulation with approximately 23,450* distributed copies across the Niagara Peninsula in the communities of Grimsby, Beamsville, Vineland, Smithville, Caistor Centre, Lincoln, and West Lincoln. The Grimsby Lincoln News is published once per week 52 weeks per year.

*Circulation numbers as posted in June 2011

CONTACT INFORMATION

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SPECIFIC APPROVALS REQUESTED

In this proceeding, Grimsby Power Inc. is requesting the following approvals:

- Approval to charge rates effective January 1, 2012 to recover a revenue requirement of $4,583,444 which includes a revenue deficiency of $812,776 as set out in Exhibit 6; the schedule of proposed rates is set out in Exhibit 8. This revenue requirement has been calculated using MIFRS;
- Approval of the proposed loss factor as set out in Exhibit 8;
- Approval of revised low voltage rates as proposed and described in Exhibit 8;
- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8;
- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of Grimsby Power Inc.'s 2011 Distribution Rates (EB-2010-0129);
- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of Grimsby Power Inc.'s 2011 Distribution Rates (EB-2010-0129);
- Approval to discontinue the Smart Meter rate adder and through a rate rider recover amounts recorded in accounts 1555 and 1556, balances as at December 31 2010, using the method of recovery described in Exhibit 9;
- Approval to recover stranded meter assets resulting from the implementation of Smart Meters through a rate rider for amounts recorded in accounts 1555 and 1556, balances as at December 31 2010, using the method of recovery described in Exhibit 9;
- Approval to recover amounts related to LRAM amounts related to activities in 2005 through 2009 over a two year period, using the method of recovery described in Exhibit 9;

- Approval to align Grimsby Power Inc.'s rate year with its fiscal year in accordance with the OEB's guidelines issued on April 15, 2010 under File No. EB-2009-0423. Grimsby Power Inc. requests that its 2012 rates be applicable starting on January 1, 2012;
- Approval of Grimsby Power Inc.'s Basic Green Energy Plan;
- Approval to dispose of the following Deferral and Variance Account balances as at December 31 2010 over a one year period using the method of recovery described in Exhibit 9:
  - 1518 Retail Cost Variance Account
  - 1521 Special Purpose Charge Assessment Variance Account – the remaining amount after May 01, 2011
  - 1548 Retail Cost Variance Account (STR)
  - 1550 Low Voltage Variance
  - 1580 RSVA - Wholesale Market Service Charges
  - 1584 RSVA - Transmission Network
  - 1586 RSVA - Transmission Connection
  - 1588 RSVA - Power
  - 1588 RSVA – Power Sub Account Global Adjustment
  - 1590 Recovery of Regulatory Assets Balances
  - 1592 PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT
- In GPI's 2010 IRM Decision (EB-2009-0198) The Board directed GPI to record in account 1592 the incremental Input Tax Credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. GPI has complied with this directive and has been recording these amounts as of July 1, 2011. The application GPI is currently submitting is based on budgeted information net of any HST ITCs GPI will receive. As a result, GPI requests approval to discontinue recording these variances as of January 1, 2012;
- Approval to discontinue the Standby Power Service Classification;

TRANSMISSION ASSETS

Grimsby Power Inc. has not had any transmission assets (>50kV) deemed previously by the Board as distribution assets and is not seeking approval to deem any transmission assets as distribution assets in this application.

PROPOSED ISSUES LIST

The Applicant would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2012 Test Year may constitute issues in this Application:

- The amount of Grimsby Power Inc.'s proposed revenue requirement;
- The reasonableness of the proposed rate base and the associated capital program for the 2012 Test Year;
- The reasonableness of the proposed operations, maintenance, and administrative expenditures for the 2012 Test Year;
- The reasonableness of the proposed load forecast for the 2012 Test Year;
- The appropriateness of Grimsby Power Inc.'s proposed cost allocation-related adjustments to class-specific revenue requirements, reflected in the proposed distribution rates;
- The appropriateness of Grimsby Power Inc.'s proposal to recover smart meter costs and include smart meter assets in its rate base;
- The appropriateness of Grimsby Power Inc.'s proposal to recover stranded meter costs which occurred as a result of the implementation of smart meters;
- The reasonableness of the proposed electricity distribution rates;
- The request to align Grimsby Power Inc.'s rate year with its fiscal year, resulting in the approval of rates effective January 1, 2012 as a consequence of this application;
- The appropriateness of Grimsby Power Inc.'s Basic Green Energy Plan under the Green Energy Act;

PROCDEURAL ORDERS / MOTIONS / NOTICES

- On January 30, 2008 the Board issued notice to electrical distributors directing which distributors would rebase in 2009 and 2010. Grimsby Power Inc. was included in Schedule B for rate rebasing in 2010.
- On November 19, 2008 Grimsby Power Inc. requested the Board to defer Grimsby Power Inc.'s rebasing until 2011.
- On January 29, 2009 the Board issued notice to electrical distributors directing which distributors would rebase in 2010 and 2011. Grimsby Power Inc. was included in Schedule B for rate rebasing in 2011.
- On June 3, 2010, Grimsby Power Inc. filed a notice of intent to file a Cost of Service rate application for rates effective January 1, 2012. Subsequently, on June 25, 2010 the Board issued its direction to Grimsby Power Inc. to file a Cost of Service Application no later than April 29, 2011 for rates to become effective January 1, 2012.
- On March 15, 2011 the Board posted a notice on the "Use of Modified IFRS as a Basis for Filing Cost of Service Applications for 2012 Rates". This notice requested distributors whose rates were being rebased in 2012 to make all reasonable efforts to file test year forecasts for their cost of service applications using modified IFRS. As a result of this notice Grimsby Power Inc. filed a notice to the Board on April 7, 2011 proposing a delay in its cost of service filing to June 24, 2011 in order that IFRS could be incorporated into its application.
- On June 22nd, 2011 the Board issued revisions to the "Chapter 2 of the Filing Requirements for Transmission and Distribution Applications" which contained a number of changes and a number of prescribed OEB MS Excel templates to include with applications. As a result of this notice Grimsby Power Inc. filed a notice to the Board on June 29, 2011 advising the Board that it would file its cost of service application in the near future.

ALIGNMENT OF RATE YEAR TO CALENDAR YEAR

Grimsby Power Inc. is seeking approval for rates with an effective date of January 1, 2012. This would align the rates with Grimsby Power Inc.'s fiscal year which is also the calendar year. Appendix B of the April 15, 2010 letter from the Board provided examples of the issues that should be addressed. A discussion on these examples as it relates to Grimsby Power Inc. is as follows:

- What are the benefits to the distributor of changing the rate year to match the fiscal year?

Aligning the rate year with the fiscal year has a number of benefits. Budgets and financial reporting at Grimsby Power Inc. are based on the calendar year. This means that budgets are not aligned with the typical May 1 rate change. If the Board were to deny costs in a rate proceeding, there could be costs that the distributor has already incurred in the first four months of the year. If the distributor defers some spending until the Board's decision, it may fall short of its planned spending for that year and have variances to explain.

There are also considerations with respect to the calculation of Payments in Lieu of Taxes. Under the current rate year, the PILs allowance is collected from May of one year to April of the next year, for a tax year that is based on the calendar year. Any "stub period" issues are ignored. This was identified in the 2006 Electricity Distribution Rate Handbook.

These issues are resolved if the rate year and the time period in which costs will be incurred are the same.

- What would be the implications of such a change from a ratepayer's perspective? For example, is it a concern that electricity consumers would see more frequent rate changes?

  Currently with the May 1 rate change both commodity and distribution rate changes occur at the same time. A distinction between commodity and distribution rate changes would provide clarity from a customer's perspective as to where the significant changes are coming from.

  The frequency of rate changes is not an issue as far as Grimsby Power Inc. is concerned. Currently with the RPP changes occurring on two separate occasions throughout the year, rate riders which start and stop at different times, and special charges which may be directed by the Ministry of Energy (at any time) customers and LDC's are used to multiple frequency changes in how rates are derived.

- Under a Cost of Service mechanism, what are the specific issues from a ratemaking perspective of transitioning to a rate year that would be aligned with the fiscal year, and how should these issues be specifically addressed?

  In Grimsby Power Inc.'s case rates have not been aligned since 2006 making it one of the few LDC's in Ontario who have not rebased. Customers have benefited from limited increases over the time period since 2006. Rates of return since 2006 have been eroded and aligning, essentially four months early, is beneficial in that it would allow Grimsby Power Inc. to earn a better rate of return over this time period.

- What would be the specific issues relating to the timeliness of existing filing requirements such as bridge year information, audited financial statements, RRR reporting, tax returns, and review and disposition of deferral and variance account balances, and how should these be specifically addressed?

By April 30th of each year the following information is available:

  - Audited financial statements
  - Trial balance for prior year in USoA format
  - Variance and deferral account balances
  - Service quality indicators
  - Information for the preparation of tax return

The information above has either been reported to the Board or is available to staff internally and therefore can be utilized in the preparation of the rate application. Actual information for the Bridge year would not be available for filing on April 30th but could be filed during the interrogatory process as has been the case with the existing process.

- Is there merit in considering the alignment during a Cost of Service application but having the implementation of the alignment take effect on January 1st of the following year as part of the distributor's first IRM based adjustment?

Grimsby Power Inc. considers this question a matter of timing and is of the opinion that the implementation of the alignment should occur with the Cost of Service application without delay.

ACCOUNTING ORDERS REQUESTED

Grimsby Power Inc. is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

Grimsby Power Inc. 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.

Grimsby Power Inc. has filed financial information for the years 2006 to 2010 actual results and for forecasted information in the 2011 Bridge Year in accordance with Canadian Generally Accepted Accounting Principles (CGAAP). The financial information for the 2012 Test Year has been filed in accordance with Modified International Financial Reporting Standards (MIFRS) in compliance with the Board's letter dated March 15, 2011. Grimsby Power Inc. has also provided comparisons between CGAAP and MIFRS where there are differences between the two accounting standards.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM

Description of Distributor

• Community Served:	Urban and Rural areas of the Town of Grimsby
• Urban Areas:	22 sq km
• Total Service Area:	67 sq km
• Rural Service Area:	45 sq km
• Distribution Type:	Electricity Distribution
• Municipal Population:	23,935
• Population of Urban Areas Served:	Not Known

A schematic diagram of Grimsby Power Inc.'s distribution system is attached in Appendix 1.2.

MAP OF DISTRIBUTION SERVICE TERRITORY

The detail shown in the map represents the municipal boundaries of the Town of Grimsby which also represents Grimsby Power Inc's Distribution Service Territory. Grimsby Power Inc.'s distribution territory is bounded municipally as follows:

- North Boundary — Lake Ontario
- West Boundary — City of Hamilton
- South Boundary — Town of Lincoln
- East Boundary — Town of Lincoln

A map of Grimsby Power Inc.'s Distribution Service Territory accompanies this Exhibit as Appendix 1.1.

MAP OF DISTRIBUTION SYSTEM

A schematic diagram of Grimsby Power Inc.'s distribution system accompanies this Exhibit as Appendix 1.2.

LIST OF NEIGHBORING UTILITIES

Grimsby Power Inc. is bounded by the following distribution utilities:

- North Boundary - No utility is present due to the presence of Lake Ontario
- West Boundary - Horizon Utilities Corporation on the western boundary
- South and East Boundary - Niagara Peninsula Energy Inc. – Peninsula West

EXPLANATION OF HOST AND EMBEDDED UTILITIES

Grimsby Power Inc. is supplied in two ways:

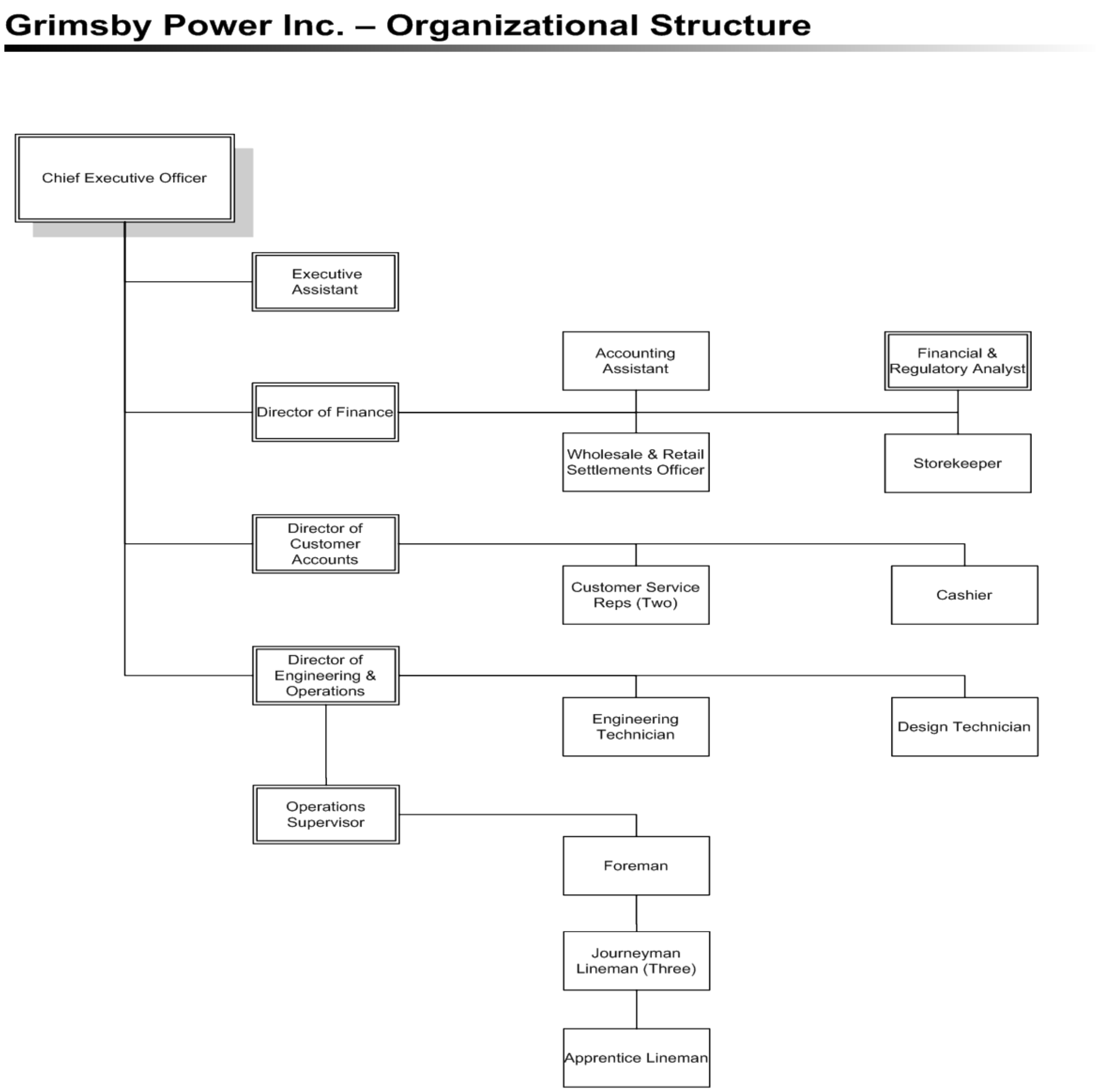
- Directly by Niagara West Transformer Corporation through demarcation point(s) at the Niagara West TS.
- Through Hydro One Networks Inc. distribution lines emanating from Beamsville TS with demarcation points at Grimsby Power Inc.'s territorial border. To the best of Grimsby Power Inc.'s knowledge 100% of the load on this Hydro One Networks Inc. distribution line is Grimsby Power Inc. load.

There are no distribution utilities embedded in Grimsby Power Inc.'s distribution system.

UTILITY ORGANIZATIONAL STRUCTURE

Grimsby Power Inc.'s organizational structure is as shown in Chart 1.1 below:

Chart 1.1 Organizational Structure



CORPORATE ENTITIES

The corporate entities related to Grimsby Power Inc. are shown in the corporate entities relationship chart shown below. The specific details of the corporate relationships are as follows:

- Niagara Power Inc. is the Holding Company. There is one shareholder - The Town of Grimsby.
- Niagara Power Inc. has four subsidiaries:
  - Grimsby Power Inc.,
  - Grimsby Energy Inc.
  - Grimsby Hydro Inc.
  - Niagara West Transformation Corporation
- Grimsby Hydro Inc. has one subsidiary:
  - Niagara Regional Broadband Networks
- Grimsby Power Inc. has two shareholders – the Town of Grimsby and FortisOntario

Grimsby Power Inc. is affiliated with Grimsby Energy Inc., Grimsby Hydro Inc., and Niagara West Transformation Corporation.

A chart illustrating Grimsby Power Inc.'s corporate family is provided as Chart 1.2 below.

Niagara Power Inc. has three Directors which are also Directors of Grimsby Power Inc.

All employees of Grimsby Power Inc. report to the CEO of Grimsby Power Inc. The CEO of Grimsby Power Inc. reports only to the Board of Grimsby Power Inc.

Grimsby Power Inc. receives or provides services from its related corporate entities as noted in Exhibit 4 under "Charges to/from affiliates for services provided".

The most significant services between is entities are:

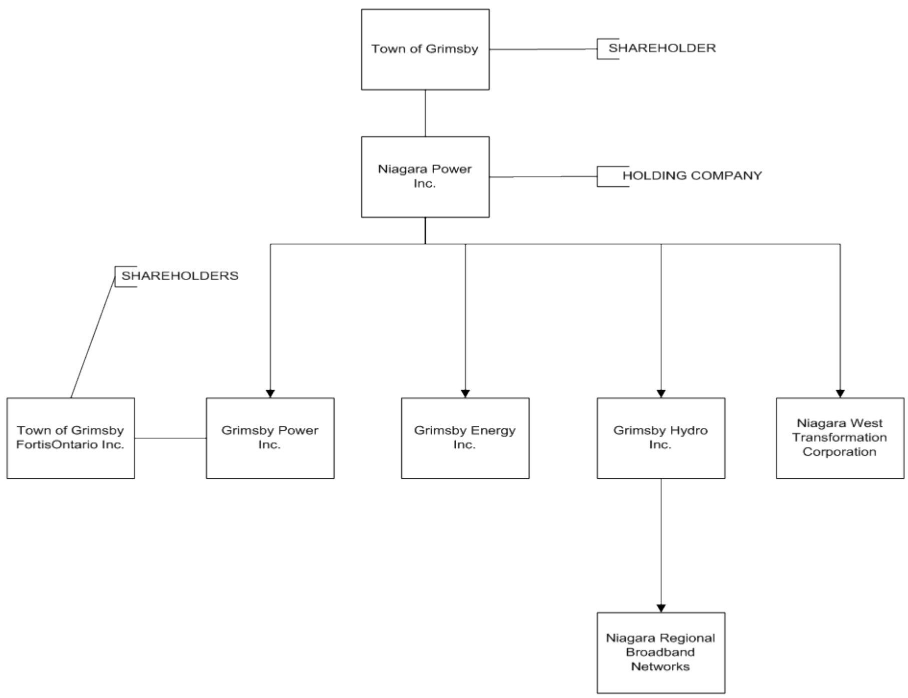
- Receives services:
  - Electrical transformation services from Niagara West Transformation Corporation;
- Provides services:
  - Electricity distribution services to the Town of Grimsby

CORPORATE ENTITIES RELATIONSHIP CHART

Chart 1.2 below illustrates the Corporate Entities Relationships:

Chart 1.2 Corporate Entities Relationship Chart

Grimsby Power Inc. – Corporate Entities Relationship Chart



PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

No changes to Grimsby Power Inc.'s corporate and operational structures are known at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS

There are no previous or outstanding Board directives.

PRELIMINARY LIST OF WITNESSES

While Grimsby Power Inc. requests that this Application be disposed of by way of a written hearing, should a technical conference or an oral hearing be necessary Grimsby Power Inc. will provide a list of potential witnesses as required.

CONDITIONS OF SERVICE

The current version of Grimsby Power Inc.'s Conditions of Service is available on Grimsby Power Inc.'s website at www.grimsbypower.com. Rates and charges which are the subject of this rate application are not contained in the Conditions of Service. Therefore, the Conditions of Service will require no changes as a result of the Cost of Service application.

SUMMARY OF THE APPLICATION

Preamble

Grimsby Power Inc. has submitted this Application in order to meet its Corporate Mission and Corporate Goals as outlined below. Current rates will result in actual Return on Rate Base in 2011 and 2012 of 3.94% and 3.07% respectively which is well below levels currently approved by the OEB. The increased rates are required to:

- Maintain current capital investment levels in infrastructure to ensure a safe and reliable distribution system.
- Support operating expenses necessary to maintain and operate the distribution system, meet customer service expectations and ensure regulatory compliance.
- Maintain current staffing requirements.

- Provide an increased level of training, exposure to utility forums and to ensure an appropriate level of knowledge transfer to support succession planning.
- To provide a reasonable rate of return to the Shareholder.

Grimsby Power Inc's Mission Statement is:

- Grimsby Power Incorporated. is committed to provide the customers of Grimsby with a safe and reliable electricity supply while operating effectively and efficiently at an equitable cost;
- Grimsby Power Incorporated will grow the business and increase shareholder value.

Grimsby Power Inc's Vision is to:

- Be adaptable;
- Continue to provide economical efficient energy;
- Be in business for our customers;
- Be a locally owned business;
- Strive to be efficient in any new operation to meet our customers' needs, and;
- Partner with others to drive economies of scale and scope.

Grimsby Power Inc.'s priorities are defined in its Corporate Goals:

Operate with a view to profitability and maximizing shareholder value while maintaining appropriate commitments to*:*

- Distribution system reliability;
- Customer satisfaction and;
- Safety and environmental protection.

Purpose and Needs

Grimsby Power Inc.'s requested revenue requirement for 2012 in the amount of $4,583,444 includes the recovery of its costs to provide distribution services, its permitted Return on Equity "ROE" and the funds necessary to service its debt.

When forecasted energy and demand levels for 2012 are considered, Grimsby Power Inc. estimates that its present rates will produce a deficiency in gross distribution revenue of $812,776 for the 2012 Test Year.

Therefore, Grimsby Power Inc. seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Table 1.1 and Exhibit 8.

The information presented in this Application represents Grimsby Power Inc.'s forecasted results for its 2012 Test Year. Grimsby Power Inc. is also presenting the forecasted results for 2011 Bridge Year and audited financial information for fiscal 2009 and 2010.

Timing

The financial information supporting the 2012 Test Year for this Application will be Grimsby Power Inc.'s fiscal year ending December 31, 2012 (the "2012 Test Year"). Grimsby Power Inc. is requesting that this information be used to set rates for the period January 1, 2012 to December 31, 2012.

Customer Impact

In preparing this application, Grimsby Power Inc. has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, Grimsby Power Inc. notes that for each of its customer classes (except Street Lighting), the current revenue to cost ratio of each rate class falls within the applicable threshold defined by the Board in the November 28, 2007, "Report on Application of Cost Allocation for Electricity Distributors" and as amended by the

Board's March 31, 2011 "Review of Electricity Distribution Cost Allocation Policy".

Customer impacts including the percent Total Bill Impact, which include revised distribution rates (monthly service charge and volumetric rates), revised low voltage rates, revised retail transmission rates, revised loss factors, LRAM rate rider, smart meter rate rider, stranded meter rate rider, and regulatory asset rate riders to dispose of the balances in the Deferral and Variance Accounts requested in this Application are set out in Table 1.2 below, for typical Residential (800 kWh per month) and Commercial (2000 kWh per month) customers. A complete listing of bill impacts for all customer classes at various levels of consumption is provided in Exhibit 8.

Table 1.2 Bill Impact: Residential and Commercial (GS<50)(Board Appendix 2-V)

Customer Class: **Residential**

Consumption **800** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 15.1100	1	$ 15.11	$ 18.4700	1	$ 18.47	$ 3.36	22.24%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	800	$ 6.88	$ 0.0105	800	$ 8.40	$ 1.52	22.09%
Low Voltage Rate Adder	per kWh	$ 0.0007	800	$ 0.56	$ 0.0007	800	$ 0.56	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0003	800	$ 0.24	$ 0.24	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0014	800	-$ 1.09	-$ 1.09	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 24.54**			**$ 31.42**	**$ 6.88**	**28.05%**
RTSR - Network	per kWh	$ 0.0059	840.16	$ 4.96	$ 0.0066	842.043	$ 5.56	$ 0.60	12.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	840.16	$ 4.12	$ 0.0054	842.043	$ 4.55	$ 0.43	10.45%
Sub-Total B - Delivery (including Sub-Total A)				**$ 33.61**			**$ 41.53**	**$ 7.91**	**23.55%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	840.16	$ 5.46	$ 0.0065	842.043	$ 5.47	$ 0.01	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge	per kWh			$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	840.16	$ 5.88	$ 0.0070	842.043	$ 5.89	$ 0.01	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	240.16	$ 18.97	$ 0.0790	242.043	$ 19.12	$ 0.15	0.78%
Total Bill (before Taxes)				**$ 104.73**			**$ 112.82**	**$ 8.09**	**7.72%**
HST		13%		$ 13.61	13%		$ 14.67	$ 1.05	7.72%
Total Bill (including Sub-total B)				**$ 118.34**			**$ 127.48**	**$ 9.14**	**7.72%**
Ontario Clean Energy Benefit [1]				**-$ 11.83**			**-$ 12.75**	**-$ 0.92**	**7.78%**
Total Bill (including OCEB)				**$ 106.51**			**$ 114.73**	**$ 8.22**	**7.72%**
Loss Factor (%)		5.02%			5.26%				

Customer Class: **General Service <50**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 25.5600	1	$ 25.56	$ 31.6200	1	$ 31.62	$ 6.06	23.71%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0100	2000	$ 20.00	$ 0.0124	2000	$ 24.80	$ 4.80	24.00%
Low Voltage Rate Adder	per kWh	$ 0.0006	2000	$ 1.20	$ 0.0006	2000	$ 1.20	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0002	2000	$ 0.40	$ 0.40	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0013	2000	-$ 2.60	-$ 2.60	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 48.75**			**$ 60.26**	**$ 11.51**	**23.62%**
RTSR - Network	per kWh	$ 0.0054	2100.4	$ 11.34	$ 0.0061	2105.11	$ 12.84	$ 1.50	13.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	2100.4	$ 9.03	$ 0.0047	2105.11	$ 9.89	$ 0.86	9.55%
Sub-Total B - Delivery (including Sub-Total A)				**$ 69.12**			**$ 83.00**	**$ 13.88**	**20.07%**
Wholesale Market Service Charge (WMSC)		$ 0.0065	2100.4	$ 13.65	$ 0.0065	2105.11	$ 13.68	$ 0.03	0.22%
Rural and Remote Rate Protection (RRRP)			2100.4	$ -		2105.11	$ -	$ -	
Special Purpose Charge			2100.4	$ -		2105.11	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2100.4	$ 14.70	$ 0.0070	2105.11	$ 14.74	$ 0.03	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	1500.4	$ 118.53	$ 0.0790	1505.11	$ 118.90	$ 0.37	0.31%
Total Bill (before Taxes)				**$ 256.81**			**$ 271.12**	**$ 14.31**	**5.57%**
HST		13%		$ 33.39	13%		$ 35.25	$ 1.86	5.57%
Total Bill (including Sub-total B)				**$ 290.20**			**$ 306.37**	**$ 16.17**	**5.57%**
Ontario Clean Energy Benefit [1]				**-$ 29.02**			**-$ 30.64**	**-$ 1.62**	**5.58%**
Total Bill (including OCEB)				**$ 261.18**			**$ 275.73**	**$ 14.55**	**5.57%**
Loss Factor (%)		5.02%			5.26%				

Smart Meters

Grimsby Power Inc. is requesting disposition of its December 31, 2010 smart meter account balances and the discontinuation of the smart meter funding adder, as outlined in Exhibit 9 of this Application.

Capital Structure

Grimsby Power Inc. is requesting the continuation of its current deemed capital structure of 40% Equity, 4% Short Term Debt, 56% Long Term Debt.

Return on Equity

Grimsby Power Inc. has assumed a return on equity of 9.58% consistent with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 8, 2011. Grimsby Power Inc. understands the Board will be finalizing the cost of capital parameters for 2012 rates based on January 2012 market interest rate information, and that adjustments to the Application may be required as a result.

Capital Expenditures

Grimsby Power Inc. continues to rebuild its distribution system consistent with its long held strategy to retire aging and at end of life 8kV Distribution Stations. This work has been ongoing since the early 1980s and reaffirmed in 2002. In addition to this work smaller capital projects such as the injection of Silicone in primary XLPE cables has been initiated to extend the life of these assets. Grimsby Power Inc. is only one of a handful of leading Ontario utilities to invest in this type of technology. As with all Ontario LDC's Grimsby Power Inc. is updating and building its distribution system to meet the demands of new and existing customers in its service territory.

In the last few years and in the years to come Grimsby Power Inc. has identified the need to increase its spending on general assets as these assets age or become technically out of step with today's requirements.

Operating and Maintenance Costs

In the PEG report titled "Benchmarking the Costs of Ontario Power Distributors" – dated March 20, 2008 Grimsby Power Inc. was included in a cohort called "Small Southern Medium-High Undergrounding with Rapid Growth". Grimsby Power Inc. has created Table 1.3 below based on the LDCs designated as part of the cohort and their respective expenses and customer numbers reported in the 2009 OEB Yearbook of Electricity Distributors published on August 25, 2010. This information shows that Grimsby Power Inc.'s OM&A costs per customer were considerably lower than its cohorts. In fact the nearest comparator was 19.4% higher than Grimsby Power Inc. For the period from 2006 to 2009 OM&A costs remained steady even though there was significant pressure to increase costs in terms of increased wages and inflation. Cost cutting measures during this period were not conducive to the operation of a healthy organization.

Looking forward from the late 2008 to early in 2010 a number of changes were put in place to stabilize the organization including:

- A partnership with Fortis Ontario
- A new corporate governance model
- A new Director of Finance
- A new CEO

With these changes in organizational structure and executive staff a number of initiatives were identified which were necessary to focus the organization. Implementing these initiatives required an increase in costs going forward. As shown in Table 1.3 the increase in costs per customer from $177 (in 2009) to $250 (in 2012) is significant but still below the highest cohort even at 2009 costs. The increase in spending is necessary to:

- Provide a sufficient number of base staff to maintain distribution assets and respond to issues affecting customer reliability;
- Provide a sufficient number of staff with specific skill sets in the financial and regulatory areas of our business to meet the ongoing and dynamic needs of the regulatory process;
- Elevate the involvement of staff in a Health & Safety Management Program;
- Increase the level of training both in day to day business tools as well as professional development;

- Increase the level of exposure to utility forums which ultimately facilitates the transfer of job knowledge (from seasoned LDC staff to new staff) and supports the succession planning process.

Details of cost increases are described in Exhibit 4.

Table 1.3 Cohort Comparison

Small Southern Medium-High Undergrounding with Rapid Growth	Grimsby Power (2012)	Grimsby Power	Orangeville Hydro	Niagara-on-the-Lake Hydro	Cooperative Hydro Embrun	Centre Wellington Hydro
Residential Customers	9703	9222	9814	6507	1757	5603
General Service <50kw Customers	683	669	1148	1230	172	714
General Service >50kw Customers	100	101	129	121	12	63
Total Customers	**10486**	**9992**	**11091**	**7858**	**1941**	**6380**
Expenses						
Operating	$ 478,166	$ 197,350	$ 329,817	$ 399,162	$ 18,349	$ 294,136
Maintenance	$ 460,674	$ 380,246	$ 430,459	$ 439,868	$ 29,551	$ 300,079
Administration	$ 1,657,417	$ 1,162,564	$ 1,616,462	$ 978,864	$ 361,102	$ 1,084,009
Other	$ 27,540	$ 30,314	$ 5,196	$ 42,555	$ 1,650	$ 44,478
Total OM&A Expenses	**$ 2,623,797**	**$ 1,770,474**	**$ 2,381,934**	**$ 1,860,449**	**$ 410,652**	**$ 1,722,702**
OM&A Per Customer	**$ 250.22**	**$ 177.19**	**$ 214.76**	**$ 236.76**	**$ 211.57**	**$ 270.02**
Percent Difference from Grimsby Power			**21.2%**	**33.6%**	**19.4%**	**52.4%**

BUDGET OVERVIEW

Grimsby Power Inc. compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital forecast. This budget information is compiled for both the 2011 Bridge Year and the 2012 Test Year.

Revenue Forecast

Grimsby Power Inc.'s energy sales and revenue forecast model were updated to reflect more recent information. This model was then used to prepare the revenues, sales and throughput volume and revenue forecast at existing rates for fiscal 2011 and 2012. The forecast is weather normalized as outlined in Exhibit 3 and considers such factors as average weather conditions and growth conditions in the area serviced by Grimsby Power Inc.

Operating Maintenance and Administration ("OM&A") Expense Forecast

The OM&A expenses for the 2011 Bridge Year and the 2012 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience, year-to-date results and expected changes for the forecast periods. Each item is reviewed account by account for each of the forecast years. Costs that are part of the allocation process have been accommodated by using burdened wage rates within the context of the budget presentation.

Capital Budget

The capital budget forecast for 2011 and 2012 is influenced by, among other factors, the highest priority capital requirements and Grimsby Power Inc.'s capacity to finance capital projects. Costs that are part of the allocation process have been accommodated by using burdened wage rates within the context of the budget presentation. All proposed capital projects are consistent with Grimsby Power Inc.'s asset management strategy with its major priority to Convert 8kV lines and equipment to 27.6kV and are outlined in Exhibit 2.

CHANGES IN METHODOLOGY

Grimsby Power Inc. is not requesting any changes in methodology in the current proceeding.

REVENUE DEFICIENCY

Grimsby Power Inc. has provided detailed calculations supporting its 2012 revenue deficiency. Grimsby Power Inc.'s net revenue deficiency is $812,776. Table 1.4 below provides the revenue deficiency calculations for the 2012 Test Year at Existing 2011 Board-approved rates and the 2012 Test Year Revenue Requirement.

Table 1.4 Calculation of Revenue Deficiency

Description	2011 Bridge Actual	2012 Test Existing Rates	2012 Test - Required Revenue
Revenue			
Revenue Deficiency			**812,776**
Distribution Revenue	3,409,489	3,430,927	3,430,927
Other Operating Revenue (Net)	331,700	339,741	339,741
Total Revenue	**3,741,189**	**3,770,668**	**4,583,444**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,359,294	1,653,300	1,653,300
Operation & Maintenance	690,251	938,840	938,840
Depreciation & Amortization	1,025,789	709,099	709,099
Property Taxes	27,000	27,540	27,540
Other - LEAP program	3,974	4,117	4,117
Capital Taxes	0	0	0
Deemed Interest	525,337	562,216	562,216
Total Costs and Expenses	**3,631,644**	**3,895,113**	**3,895,113**
Less OCT Included Above	0	0	0
Total Costs and Expenses Net of OCT	**3,631,644**	**3,895,113**	**3,895,113**
Utility Income Before Income Taxes	**109,545**	**(124,444)**	**688,331**
Income Taxes:			
Corporate Income Taxes	43,786	(63,681)	62,299
Total Income Taxes	**43,786**	**(63,681)**	**62,299**
Utility Net Income	**65,759**	**(60,763)**	**626,032**
Capital Tax Expense Calculation:			
Total Rate Base	15,005,665	16,336,952	16,336,952
Exemption	0	0	0
Deemed Taxable Capital	**15,005,665**	**16,336,952**	**16,336,952**
Ontario Capital Tax	0	0	0
Income Tax Expense Calculation:			
Accounting Income	109,545	(124,444)	688,331
Tax Adjustments to Accounting Income	45,451	(286,400)	(286,400)
Taxable Income	**154,996**	**(410,844)**	**401,932**
Income Tax Expense	43,786	(63,681)	62,299
Tax Rate Refecting Tax Credits	28.25%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	15,005,665	16,336,952	16,336,952
Interest Expense	525,337	562,216	562,216
Net Income	65,759	(60,763)	626,032
Total Actual Return on Rate Base	**591,095**	**501,453**	**1,188,248**
Actual Return on Rate Base	3.94%	3.07%	7.27%
Required Return on Rate Base:			
Rate Base	15,005,665	16,336,952	16,336,952
Return Rates:			
Return on Debt (Weighted)	5.83%	5.74%	5.74%
Return on Equity	9.00%	9.58%	9.58%
Deemed Interest Expense	525,337	562,216	562,216
Return On Equity	540,204	626,032	626,032
Total Return	**1,065,541**	**1,188,248**	**1,188,248**
Expected Return on Rate Base	7.10%	7.27%	7.27%
Revenue Deficiency After Tax	**474,445**	**686,795**	**0**
Revenue Deficiency Before Tax	**661,248**	**812,776**	**0**

CAUSES OF REVENUE DEFICIENCY

Grimsby Power Inc.'s calculation of its 2012 revenue deficiency is provided in Exhibit 6.

The revenue deficiency is primarily the result of:

- Increases in OM&A costs including depreciation expense. Including the 2012 Test Year, Grimsby Power Inc. is forecasting OM&A expenses to have increased at a compounded annual growth rate of 9.66% (CGAAP) per year since 2006. Grimsby Power Inc. has provided a detailed explanation of changes in operating expenses in Exhibit 4.

  Depreciation expense (CGAAP) has increased as a direct result of an elevated level (above depreciation expense) of capital spending.

- Capital distribution expenditures (not including smart meters and including capital contributions) for the period from 2006 to 2012 average $1,424,435. The level of expenditure exceeds the annual depreciation levels resulting in an increased rate base on which the rate of return is calculated. Grimsby Power Inc. is committed to ensuring the reliability of the distribution system and will continue to invest in capital infrastructure in 2011 and 2012 at a level exceeding depreciation. Changes in the Rate Base are discussed further in Exhibit 2.

FINANCIAL STATEMENTS – 2009 AND 2010

Grimsby Power Inc.'s Audited Financial Statements accompany this Exhibit as Appendix 1.3.

PRO FORMA FINANCIAL STATEMENTS – 2011 AND 2012

The Pro Forma Statements for the 2011 Bridge Year and the 2012 Test Year accompany this Exhibit as Appendix 1.4.

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

No reconciliation is required between the 2012 Pro Forma statement and the revenue deficiency statement.

INFORMATION ON PARENT AND SUBSIDIARIES OF THE APPLICANT

Grimsby Power Inc. (GPI) is a subsidiary of Niagara Power Inc. (NPI). Grimsby Power Inc. does not have any subsidiaries. Niagara Power Inc. does not produce an annual report.

RATING AGENCY REPORT(S)

Grimsby Power Inc. does not have a rating agency report.

RECENT PLANNED ISSUANCES

Grimsby Power Inc. does not have any recent planned issuances.

MATERIALITY THRESHOLDS

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued by the Board June 28, 2011 states the relevant default materiality threshold is based on the level of distribution revenue requirement. Grimsby Power's revenue requirement as set by the 2006 EDR is $3,523,265 and the proposed revenue requirement for 2012 is $4,583,444. Chapter 2 of the Filing Requirements for Transmission and Distribution Applications states that the materiality threshold is "$50,000 for distributors with a distribution revenue requirement less than or equal to $10 million".

In an effort to provide a thorough and relevant analysis Grimsby Power Inc. has used a materiality threshold of $50,000 throughout this Application.

Appendix 1.1 Map of Grimsby Power Inc.'s Service Territory


GRIMSBY POWER INCORPORATED SERVICE AREA
LAKE ONTARIO
LAKE ONTARIO
CITY OF HAMILTON
TOWN OF LINCOLN
TOWNSHIP OF WEST LINCOLN
CON. I
CON. II
CON. III
CON. IV
CON. V
CON. VI
LOT 23
LOT 22
LOT 21
LOT 20
LOT 19
LOT 18
LOT 17
LOT 16
LOT 15
LOT 14
LOT 13
LOT 12
LOT 11
LOT 10
LOT 9
LOT 8
LOT 7
LOT 6
LOT 5
LOT 4
LOT 3
LOT 2
LOT 1

Appendix 1.2 Schematic of Grimsby Power Inc.'s Distribution System


Town of Grimsby
27.6/8.0 KV
OPERATING MAP
GRIMSBY POWER INCORPORATED
Lake Ontario
City of Stoney Creek
Town of Lincoln
KERMAN STATION
BAKER STATION
Legend
SWITCHING_CABINETS
SOURCE
UNDERGROUND_OPEN_POINT
STEP_TRANSFORMER
PWR_TRANSFORMER
RECLOSER
FUSE
Open
Closed
SWITCH
Open
Closed
SWCAB_GOS
Open
Closed
SWCAB_FUS
Open
Closed
OH_PRIMARY
<all other values>
B, 16000
B, 4800
R, 16000
R, 4800
RB, 27600
RWB, 27600
RWB, 8320
W, 16000
W, 4800
WB, 27600
UG_PRIMARY
<all other values>
B, 16000
B, 4800
R, 16000
R, 4800
RB, 27600
RWB, 27600
RWB, 8320
W, 16000
W, 4800
0 0.25 0.5 1
Kilometers

Appendix 1.3 Copy of Grimsby Power Inc.'s Audited Financial Statements for 2009

Financial statements of

Grimsby Power Incorporated

December 31, 2009

Grimsby Power Incorporated
December 31, 2009

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Auditors' Report

To the Shareholder of
Grimsby Power Incorporated

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

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

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

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
March 10, 2010

Grimsby Power Incorporated

Statement of earnings and retained earnings
year ended December 31, 2009

	2009	2008
	$	$
Sales	**16,765,862**	16,464,704
Cost of sales	**13,452,387**	13,141,129
Gross profit	**3,313,475**	3,323,575
Other income		
Interest income	**18,558**	117,564
Miscellaneous	**320,554**	256,750
	339,112	374,314
	3,652,587	3,697,889
Expenses		
Amortization	**967,541**	842,962
Administration	**687,171**	634,396
Billing and collecting	**447,268**	470,688
Interest	**440,872**	472,053
Maintenance	**380,246**	409,936
Operations	**197,350**	200,473
Property taxes	**30,314**	27,150
Marketing	**11,428**	33,426
	3,162,190	3,091,084
Earnings before payment in lieu of taxes	**490,397**	606,805
Payments in lieu of taxes (Note 9)		
Current	**(625)**	219,356
Future	**131,123**	(59,000)
	130,498	160,356
Net earnings	**359,899**	446,449
Retained earnings, beginning of year	**1,087,997**	2,741,548
Adjustment for change in accounting policy (Note 3)	**(210,206)**	-
Dividends	**(1,200,000)**	(2,100,000)
Retained earnings, end of year	**37,690**	1,087,997

Grimsby Power Incorporated

Balance sheet
as at December 31, 2009

	2009	2008
	$	$
Assets		
Current assets		
Cash	**1,142,965**	1,581,984
Accounts receivable		
Service revenue	**663,774**	605,755
Other	**313,376**	144,587
Due from related parties	**-**	10,424
Payment in lieu of taxes receivable	**177,053**	-
Unbilled revenue	**1,530,845**	1,669,759
Inventory	**181,884**	185,209
Prepaid expenses	**33,208**	90,722
	4,043,105	4,288,440
Capital assets and intangibles (Note 5)	**11,405,282**	11,019,011
Deposit on long term asset	**94,500**	-
Investment (Note 6)	**-**	1,200,000
Future payments in lieu of taxes	**1,119,859**	480,000
	16,662,746	16,987,451
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**2,597,321**	2,558,624
Due to related parties	**31,410**	-
Payment in lieu of taxes payable	**-**	21,641
	2,628,731	2,580,265
Long-term liabilities		
Customers' deposit	**341,239**	307,638
Developers' deposit	**12,659**	12,524
Promissory note (Note 7)	**5,782,746**	5,782,746
	6,136,644	6,102,908
Regulatory liabilities (Note 8)	**2,006,213**	1,362,813
Commitments and contingent liabilities (Note 14)		
Shareholders' equity		
Share capital		
Authorized		
Unlimited common shares		
Issued and outstanding		
1,001 common shares	**5,782,747**	5,782,747
Contributed capital	**70,721**	70,721
Retained earnings	**37,690**	1,087,997
	5,891,158	6,941,465
	16,662,746	16,987,451

Approved by the Board

________________________ Director

________________________ Director

Grimsby Power Incorporated

Statement of cash flows
year ended December 31, 2009

	2009	2008
	$	$
Operating activities		
Net earnings	**359,899**	446,449
Items not involving cash		
Amortization		
(including amounts charged to operating accounts)	**967,541**	875,310
Loss on disposal of capital assets	**2,281**	1,598
Future payments in lieu of taxes	**131,123**	(59,000)
Change in non-cash working capital (Note 10)	**(145,218)**	(45,704)
Increase (decrease) in customer and developer deposits	**33,736**	(13,047)
(Decrease) increase in regulatory liabilities	**(337,788)**	107,056
	1,011,574	1,312,662
Investing activities		
Proceeds on sale of investment	**1,200,000**	-
Additions to capital assets	**(1,446,911)**	(1,047,176)
Deposit on long-term asset	**(94,500)**	-
Proceeds on sale of capital assets	**3,010**	110
	(338,401)	(1,047,066)
Financing activities		
Capital contributions received	**87,808**	82,200
Dividends paid	**(1,200,000)**	(2,100,000)
	(1,112,192)	(2,017,800)
Net change in cash and cash equivalents	**(439,019)**	(1,752,204)
Cash and cash equivalents, beginning of year	**1,581,984**	3,334,188
Cash and cash equivalents, end of year	**1,142,965**	1,581,984
Supplemental disclosures		
Payments for interest	**440,872**	472,053
Payments for income taxes	**227,407**	(375,852)

1. Nature of operations

Grimsby Power Incorporated (the "Company"), is incorporated under the laws of Ontario and its principal business activity is to distribute power to consumers within the Town of Grimsby.

The Company is a regulated electricity distribution Company that owns and operates the electricity infrastructure, distributing a safe, reliable delivery of electricity to homes and businesses in the Town of Grimsby. The Company is regulated by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, and for ensuring that distribution companies fulfill their obligations to connect and service customers.

2. Significant accounting policies

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and policies as set forth in the Accounting Procedures Manual issued by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998.

Significant accounting policies are summarized below:

Regulation

The Company is regulated by the OEB and any power rates adjustments require OEB approval. The following accounting policies under the regulated environment differ from GAAP for companies operating under an unregulated environment:

<u>Regulatory assets and liabilities</u>

Regulatory assets and liabilities represent differences between amounts collected through rates (OEB approved) and actual costs incurred by the distributor. Regulatory assets and liabilities on the balance sheet at year-end consist of Settlement Variances on the Cost of Power, Deferred Charges, and the associated regulated interest. Account balances and current year activities are detailed in Note 8.

<u>Smart Meter Initiative</u>

The Province of Ontario has committed to have "Smart Meter" electricity meters installed in 800,000 homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

The Corporation has installed 235 Smart Meters as of the end of 2009 and anticipates having installed a total of 9,885 Smart Meters upon completion of its mass deployment.

Cash and cash equivalents

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

Unbilled revenue

Unbilled revenue is accrued from the last meter reading date to the end of the period.

Inventory

Inventory is valued at the lower of cost and net realizable value.

Capital assets

Capital assets are stated at cost. The cost and related accumulated amortization of the capital assets are removed from the accounts at the end of their estimated service lives except in those instances where specific identification permits their removal at retirement or disposition. Gains and losses at retirement or disposition are credited or charged to income. Contributions in aid of capital assets are recorded as deferred credits and amortized to income over the life of the related assets.

2. Significant accounting policies (continued)

Asset	Basis	Rate
Buildings	Straight-line	25 - 50 years
Distribution stations	Straight-line	25 years
Distribution plant	Straight-line	25 years
General equipment	Straight-line	3 - 10 years
Capital contribution	Straight-line	25 years

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing Company assets. Contributed capital has been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

Impairment of long-lived assets

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

Investment

The investment is recorded at cost.

Payments in lieu of taxes ("PILs")

The Company is currently exempt from taxes under the Income Tax Act (Canada) ("ITA") and the Ontario Corporations Tax Act ("OCTA"). Pursuant to the Electricity Act, 1998 (Ontario) (EA), the Company is required to compute taxes under the ITA and OCTA and remit such amounts thereunder computed to the Ministry of Finance (Ontario).

The Company provides for PILs using the asset and liability method. Under this method, future tax assets and liabilities are recognized, to the extent such are determined likely to be realized, for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases.

Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the Company at that time.

PILs recoverable from loss carryforwards are recorded in future payments in lieu of taxes on the balance sheet at the current enacted statutory tax rates expected to apply when recovery of the loss carryforwards are expected to be recovered.

Customer and developer deposits

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

2. Significant accounting policies (continued)

Asset retirement obligations

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

Use of estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements including changes as a result of future regulatory decisions.

Accounts receivable, unbilled revenue and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate valuation allowance. Inventory is recorded net of provisions for obsolescence. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

Revenue recognition

Revenue is recognized on the accrual basis, which includes an estimate of unbilled revenue. Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis on power used. Any discrepancies in the revenue collected and the associated cost of power to distribute are charged to regulatory assets.

Financial instruments

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

The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Unbilled revenue	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Promissory note	Other liabilities
Customers' and developers' deposits	Other liabilities

Held for trading

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

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

2. Significant accounting policies (continued)

Financial instruments (continued)

Loans and receivables

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

Other liabilities

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

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

Derivatives

The Company does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the presentation of these financial statements.

3. Changes in accounting policies

Effective January 1, 2009, the Company adopted the following new Canadian Institute of Chartered Accountants' (CICA) Handbook sections:

- 1100, Generally Accepted Accounting Principles
- 3064, Goodwill and Intangible Assets

Rate regulated accounting

CICA Handbook Section 1100 was amended to remove the temporary exemption that provided relief to entities subject to rate regulation from the requirement to apply Section 1100 to the recognition and measurement of assets and liabilities arising from rate regulation. In accordance with Section 1100, the Company determined all of its regulatory assets and liabilities qualified for recognition under Canadian GAAP.

The implementation of this standard did not have any impact on the Company's results of operations or financial position.

Goodwill and intangible assets

On January 1, 2009, the Company adopted CICA Section 3064, Goodwill and Intangible Assets, which replaced Section 3062, Goodwill and Other Intangible Assets, and which resulted in the withdrawal of Section 3450, Research and Development Costs and of Emerging Issues Committee ("EIC") Abstract 27, Revenues and Expenditures During the Pre-operating Period, and the amendment of Accounting Guideline ("AcG") 11, Enterprises in the Development Stage. The new Section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. In particular, the new standard sets out specific criteria for the recognition of intangible assets and clarifies the application of the concept of matching costs with revenues, so as to eliminate the practice of recognizing as assets items that do not meet the definition of an asset or satisfy the recognition criteria for an asset. The adoption of this section had no impact on the financial statements.

3. Changes in accounting policies (continued)

Regulatory liabilities

Effective January 1, 2009, the Company changed its accounting policy with respect to the recoverability of future payments in lieu of taxes from ratepayers. This change was made to conform with current year modification of industry standards with regards to the accounting treatment of future payments in lieu of taxes. This accounting policy was applied retrospectively without restatement of prior year balances. Consequently, opening retained earnings as at January 1, 2009 has been decreased by $210,206, with a corresponding decrease in the future payments in lieu of taxes asset by $210,206.

4. Future changes in accounting policies

International financial reporting standards (IFRS)

In February 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP effective January 1, 2011. The Company is currently evaluating the impact of the adoption of IFRS on its financial statements. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable or estimable.

5. Capital assets and intangibles

			2009	2008
	Cost	Accumulated amortization	Net book value	Net book value
	$	$	$	$
Land	111,556	-	111,556	111,556
Buildings	684,506	328,977	355,529	371,336
Distribution stations	143,555	143,555	-	-
Distribution plant	25,324,324	11,670,950	13,653,374	13,389,681
General equipment and intangibles	1,660,303	1,272,002	388,301	324,053
Capital contribution	(4,109,851)	(1,006,373)	(3,103,478)	(3,177,615)
	23,814,393	12,409,111	11,405,282	11,019,011

During the year, the Company received $130,482 (2008 – $162,610) of capital contributions in aid of construction.

6. Investment

The investment was comprised of 120 non-voting Class A special shares of Niagara West Transformation Corporation, a joint venture of the Company's parent. On June 30, 2009, this investment was sold to the Company's parent for carrying value of $1,200,000 resulting in $nil gain/loss.

7. Promissory note

The promissory note matures on February 1, 2020 and is payable to the Town of Grimsby. The note bears interest at the rate of 7.25% per annum.

8. Regulatory liabilities

	2009	2008
	$	$
Regulatory liabilities		
Settlement variances	**(2,140,038)**	(1,324,084)
Smart meters	**114,496**	(57,900)
Regulatory assets recovery amount	**19,329**	19,171
	(2,006,213)	(1,362,813)

Net regulatory liabilities represent amounts recovered from customers in excess of costs incurred at OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future settlement in electricity distribution rates. Management assesses the future uncertainty with respect to the recovery of those amounts, and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision concerning adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Regulatory liabilities incur interest at prescribed rates. In 2009, the rates ranged from 0.55% to 2.45% (2008 - 3.35% to 5.14%).

Settlement variances – represent amounts that have accumulated since Market Opening and comprise:

(a) Variances between amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the wholesale electricity market and grid, various wholesale market settlement charged and transmission charges, and the amounts billed to customers by the Company based on the OEB approved wholesale market service rate; and,

(b) Variances between the amounts charged by the IESO for energy commodity costs and the amounts billed to customers by the Company based on OEB approved rates.

Smart meters – The Province of Ontario has committed to have "Smart Meter" electricity meters installed in 800,000 homes and small businesses by the end of 2008 and throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals. Bill 21, Energy Conservation and Responsibility Act, provides the legislative framework and regulations to support this initiative.

Included in distribution rates, effective May 1, 2006, is a charge for smart meters of $0.27 (2008 - $0.27) per metered customer per month. Consistent with the OEB's direction and pending further guidance, all smart meter related expenditures and recoveries are currently being deferred in regulatory accounts.

Regulatory assets recovery amount – represents costs incurred by the Company as of December 31, 2004 which have been approved for recovery through rates net of amounts recovered from customers.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates that the Company may charge and the costs that the Company may recover, including the balance of its regulatory assets.

In the absence of rate regulation, Canadian generally accepted accounting principles would require the Company to record the costs and recoveries described above in the operating results of the year in which they are incurred and reported earnings before income taxes would be $528,270 lower (2008 - $107,056 higher) than reported.

8. Regulatory liabilities (continued)

Rate regulation

The Company is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the Ontario Energy Board Act (1998). The OEB has the power and responsibility to approve or fix rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

In January 2000, the OEB established that distribution rates would be subject to Performance Based Regulation ("PBR"), a method of regulation whereby distribution rates are reduced annually to reflect productivity improvements required on the Company. Under this rate methodology, rates also include regulated amounts for return on Company equity and debt, which were initially determined by the OEB to be 9.88% and 7.25%, respectively. While the initial PBR regulatory framework provided for those regulatory rates of return, subsequent regulation and Provincial Government initiatives prevented distribution companies from fully achieving the theoretical rate of return on equity.

In 2005, the Company filed rate applications to adjust its distribution charges to provide for the full theoretical regulatory rate of return of 9.88% and continued recovery of its regulatory assets. As mandated by the OEB, the rate increase is subject to a financial commitment by the Company to invest $221,745 in conservation and demand management activities over the period July 1, 2004 to April 30, 2008. Spending on this program was completed in 2008.

In 2006, the OEB approved the Company's 2006 distribution rates providing for a revised rate of return of 9.0% effective May 1, 2006.

9. Payments in lieu of taxes

The Company's income tax expense for the year ended December 31, 2009 consists of the following:

Temporary differences which give rise to future payments in lieu of tax assets and liabilities are as follows:

	2009	2008
	$	$
Allowance for doubtful accounts	**2,167**	1,885
Property, plant and equipment	**979,021**	208,321
Regulatory liabilities	**138,671**	269,794
Future payments in lieu of tax assets (liabilities)	**1,119,859**	480,000

The impact of differences between the Company's reported payments in lieu of corporate income taxes and the expense that would otherwise result from the application of the combined statutory income tax rate of 33% (2008 – 33.5%) is as follows:

9. Payments in lieu of taxes (continued)

	2009	2008
	$	$
Basic taxes applied to income before PILs	**161,831**	203,280
Increase (decrease) in PILs resulting from:		
Tax basis of depreciable capital assets and goodwill in excess of accounting basis	**(20,887)**	1,739
Change in future tax rate	**131,123**	(13,110)
Change in regulatory liabilities	**(111,470)**	-
Prior year adjustments	**(32,043)**	-
Other	**1,944**	(31,553)
	130,498	160,356

10. Change in non-cash working capital

	2009	2008
	$	$
Cash provided by (used in)		
Accounts receivable		
Service revenue	**(58,019)**	317,184
Other	**(168,789)**	(23,146)
Due to/from related parties	**41,834**	-
Unbilled revenue	**138,914**	(79,671)
Inventory	**3,325**	481
Prepaid expenses	**57,514**	12,987
Accounts payable and accrued liabilities	**38,697**	(853,180)
Payments in lieu of taxes payable/receivable	**(198,694)**	579,641
	(145,218)	(45,704)

The Company acquired property and equipment through non-cash capital contributions of $42,674 (2008 - $80,410).

During the year, the Company received (refunds)/made payments in lieu of taxes in the amount of $227,407 (2008 – ($375,852)).

11. Related party transactions

The following transactions have been made with the parent company, shareholder of the parent company and a subsidiary of the parent company:

	2009	2008
	$	$
Revenue		
Service Revenue	**348,991**	383,683
Other	**18,357**	3,220
Expenses		
Interest charges	**419,249**	419,249
Other expenses	**39,930**	49,161
Connection fees	**369,666**	377,552
Management fees	**186,525**	223,445

11. Related party transactions (continued)

These transactions have taken place in the ordinary course of business and are recorded at the exchange amount.

Included in accounts receivable are $9,440 (2008 - $43,384) owing from related parties and included in accounts payable are $459,962 (2008 – $419,249) owing to related parties. These balances are non-interest bearing with no fixed terms of repayment.

During the year, the Company migrated its billing system to a SAP platform. Migration services were provided by a shareholder of the parent company for nil consideration. No amount has been recognized in the accounts relating to this transaction measured at the exchange amount. The Company has a contractual commitment to pay $3,500 per month for system administration and non-system related support to this related party.

12. Pension agreements

The Company makes contributions to the Ontario Municipal Employees Retirement System ("OMERS"), which is a multi-employer plan, on behalf of its full-time staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by an employee based on the length of services and rate of pay.

Contributions during the year were 6.5% (2008 – 6.5%) for employee earnings below the year's maximum pensionable earnings and 9.6% (2008 – 9.6%) thereafter.

The amount contributed in 2009 is $63,503 (2008 – $59,991) and is included as an expenditure in the Statement of Earnings.

13. 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 should losses be experienced by MEARIE, for the years in which the company and its predecessor company was a member.

To December 31, 2009, the Company has not been made aware of any additional assessments. Participation in MEARIE covers a one year underwriting period which expires January 1, 2010. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next underwriting term.

14. Commitments and contingent liabilities

a) A letter of credit in the amount of $964,845 has been issued in favour of the Independent Electricity Market Operator ("IMO") as security for the Company's purchase of electricity through the IMO. No amounts were drawn down on the letter of guarantee at year-end.

b) The Company has entered into a contract to purchase computer software for $175,000 to be implemented in 2010.

c) The Company has guaranteed the indebtedness of Niagara West Transformation Corporation, a joint venture of the parent company. On June 30, 2009, the investment in Niagara West Transformation Corporation was transferred to the parent company.

d) A class action claiming $500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceeding brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas) ("Enbridge").

14. Commitments and contingent liabilities (continued)

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

In 2007, Enbridge filed an application to the Ontario Energy Board to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008, the OEB approved the 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.

At this time it is not possible to quantify the effect, if any, on the financial statements of Grimsby Power Incorporated.

15. Capital disclosures

The main objectives of the Corporation when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

As at December 31, 2009, the Company's definition of capital includes shareholder's equity and promissory note. This definition remains unchanged from prior years. As at December 31, 2009, shareholder's equity amounts to $5,891,158 (2008 - $6,941,465) and promissory note amounts to $5,782,746 (2008 - $5,782,746). The Company's capital structure as at December 31, 2009 is 50% debt and 50% equity (2008 – 45% debt and 55% equity). There have been no changes in the Company's approach to capital management during the year.

The Corporation has customary covenants typically associated with long-term debt. The Corporation is in compliance with all credit agreement covenants and limitations associated with its long-term debt.

16. Financial instruments and risk management

The Company, through its financial assets and liabilities, has exposure to liquidity and credit risks.

Liquidity risk

The Company's objective is to have sufficient liquidity to meets its liabilities when due. The Company monitors its cash balance and cash flows generated from operations to meet its requirements.

Credit risk

Financial instruments are exposed to credit risk as a result of the counter-party defaulting on its obligations. However, the Company has a large number of diverse customers minimizing concentration of credit risk. The Company requires customers to provide security deposits subject to OEB regulations.

Fair value

The carrying values of cash, accounts receivable, due to/from related parties, unbilled revenue, and accounts payable and accrued liabilities approximate their fair values due to the immediate or short-term maturity of these financial instruments.

Customer and developer deposits have a fair value that approximates carrying value. Interest is paid on deposits on a monthly basis at a market rate, as directed by the Ontario Energy Board.

The promissory note payable to the Town of Grimsby is valued at its face value. It is not practicable within constraints of timeliness or cost to reliably measure its fair value.

17. Comparative figures

Certain comparative figures have been reclassified to conform to the current year's presentation.

Copy of Grimsby Power Inc.'s Audited Financial Statements for 2010

Financial statements of

Grimsby Power Incorporated

December 31, 2010

Grimsby Power Incorporated
December 31, 2010

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Independent Auditor's Report

To the Shareholder of
Grimsby Power Incorporated

We have audited the accompanying financial statements of Grimsby Power Incorporated, which comprise the balance sheet as at December 31, 2010, and the statements of earnings and retained earnings and of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

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 comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Grimsby Power Incorporated as at December 31, 2010 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
April 26, 2011

Grimsby Power Incorporated

Statement of earnings and retained earnings
year ended December 31, 2010

	2010	2009
	$	$
Sales	**18,747,911**	16,765,862
Cost of sales	**15,370,110**	13,452,387
Gross profit	**3,377,801**	3,313,475
Other income		
Interest income	**29,695**	18,558
Miscellaneous	**265,931**	320,554
	295,626	339,112
	3,673,427	3,652,587
Expenses		
Amortization	**975,166**	967,541
Administration	**684,872**	687,171
Billing and collecting	**487,848**	447,268
Interest	**459,637**	440,872
Maintenance	**397,850**	380,246
Operations	**179,325**	197,350
Property taxes	**25,130**	30,314
Marketing	**11,749**	11,428
	3,221,577	3,162,190
Earnings before payment in lieu of taxes	**451,850**	490,397
Payments in lieu of taxes (Note 7)		
Current	**82,162**	(625)
Future	**98,229**	131,123
	180,391	130,498
Net earnings	**271,459**	359,899
Retained earnings, beginning of year	**37,690**	1,087,997
Adjustment for change in accounting policy	**-**	(210,206)
Dividends	**-**	(1,200,000)
Retained earnings, end of year	**309,149**	37,690

Grimsby Power Incorporated

Balance sheet
as at December 31, 2010

	2010	2009
	$	$
Assets		
Current assets		
Cash	**1,602,923**	1,142,965
Accounts receivable		
Service revenue	**753,211**	663,774
Other	**225,369**	313,376
Due from related parties	**12,333**	-
Payment in lieu of taxes receivable	**44,115**	177,053
Unbilled revenue	**1,633,329**	1,530,845
Inventory	**227,793**	181,884
Prepaid expenses	**85,788**	33,208
	4,584,861	4,043,105
Capital assets and intangibles (Note 3)	**11,307,295**	11,405,282
Deposit on long term asset	**94,500**	94,500
Regulatory assets (Note 6)	**854,127**	-
Future payments in lieu of taxes	**40,442**	138,671
Regulatory assets - future payments in lieu of taxes	**1,013,324**	981,188
	17,894,549	16,662,746
Liabilities		
Current liabilities		
Bank loan (Note 4)	**1,600,000**	-
Accounts payable and accrued liabilities	**2,554,080**	2,597,321
Due to related parties	**-**	31,410
Payment in lieu of taxes payable	**-**	-
	4,154,080 -	2,628,731
Long-term liabilities		
Customers' deposit	**290,304**	341,239
Developers' deposit	**491,478**	12,659
Promissory note (Note 5)	**5,782,746**	5,782,746
Regulatory liabilities (Note 6)	**-**	1,025,025
Regulatory liabilities - future payments in lieu of taxes	**1,013,324**	981,188
	7,577,852	8,142,857
Commitments and contingent liabilities (Note 12)		
Shareholder's equity		
Share capital		
Authorized		
Unlimited common shares		
Issued and outstanding		
1,001 common shares	**5,782,747**	5,782,747
Contributed capital	**70,721**	70,721
Retained earnings	**309,149**	37,690
	6,162,617	5,891,158
	17,894,549	16,662,746

Approved by the Board

______________________________ Director

______________________________ Director

Grimsby Power Incorporated

Statement of cash flows
year ended December 31, 2010

	2010	2009
	$	$
Operating activities		
Net earnings	**271,459**	359,899
Items not involving cash		
Amortization		
(including amounts charged to operating accounts)	**975,166**	967,541
Loss on disposal of capital assets	**464**	2,281
Loss on disposal of stranded meters	**391,841**	-
Future payments in lieu of taxes	**98,229**	131,123
Change in non-cash working capital (Note 8)	**(156,449)**	(145,218)
Increase in customer and developer deposits	**427,884**	33,736
Change in regulatory assets/liabilities	**(1,879,152)**	(337,788)
	129,442	1,011,574
Investing activities		
Proceeds on sale of investment	**-**	1,200,000
Additions to capital assets	**(2,137,126)**	(1,446,911)
Deposit on long-term asset	**-**	(94,500)
Proceeds on sale of capital assets	**300**	3,010
	(2,136,826)	(338,401)
Financing activities		
Capital contributions received	**867,342**	87,808
Proceeds on bank loan	**1,600,000**	-
Dividends paid	**-**	(1,200,000)
	2,467,342	(1,112,192)
Net change in cash and cash equivalents	**459,958**	(439,019)
Cash and cash equivalents, beginning of year	**1,142,965**	1,581,984
Cash and cash equivalents, end of year	**1,602,923**	1,142,965
Supplemental disclosures		
Payments for interest	**459,637**	440,872
Receipts in lieu of taxes	**51,045**	227,407

1. Nature of operations

Grimsby Power Incorporated (the "Company"), is incorporated under the laws of Ontario and its principal business activity is to distribute power to consumers within the Town of Grimsby.

The Company is a regulated electricity distribution Company that owns and operates the electricity infrastructure, distributing a safe, reliable delivery of electricity to homes and businesses in the Town of Grimsby. The Company is regulated by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, and for ensuring that distribution companies fulfill their obligations to connect and service customers.

2. Significant accounting policies

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and policies as set forth in the Accounting Procedures Manual issued by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998.

Significant accounting policies are summarized below:

Regulation

The Company is regulated by the OEB and any power rates adjustments require OEB approval. The following accounting policies under the regulated environment differ from GAAP for companies operating under an unregulated environment:

Regulatory assets and liabilities

Regulatory assets and liabilities represent differences between amounts collected through rates (OEB approved) and actual costs incurred by the distributor. Regulatory assets and liabilities on the balance sheet at year-end consist of Settlement Variances on the Cost of Power, Deferred Charges, and the associated regulated interest. Account balances and current year activities are detailed in Note 6.

Smart Meter Initiative

The Province of Ontario committed to having "Smart Meter" electricity meters installed in certain homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

The Corporation has installed 10,035 Smart Meters upon completion of its meter deployment.

Cash and cash equivalents

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

Unbilled revenue

Unbilled revenue is accrued from the last meter reading date to the end of the period.

Inventory

Inventory is valued at the lower of cost and net realizable value.

Capital assets and intangibles

Capital assets and intangibles are stated at cost. The cost and related accumulated amortization of the capital assets and finite lived intangibles are removed from the accounts at the end of their estimated service lives except in those instances where specific identification permits their removal at retirement or disposition. Gains and losses at retirement or disposition are credited or charged to income. Contributions in aid of capital assets and intangibles are recorded as deferred credits and amortized to income over the life of the related assets.

2. Significant accounting policies (continued)

Capital assets and intangibles (continued)

Asset	Basis	Rate
Buildings	Straight-line	25 - 50 years
Distribution stations	Straight-line	25 years
Distribution plant	Straight-line	25 years
General equipment and intangibles	Straight-line	3 - 10 years
Capital contribution	Straight-line	25 years

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing Company assets. Contributed capital has been charged to capital assets and recorded as an offset to capital assets. Amortization is on a straight-line basis over 25 years.

Impairment of long-lived assets

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

Payments in lieu of taxes ("PILs")

The Company is currently exempt from taxes under the Income Tax Act (Canada) ("ITA") and the *Taxation Act, 2007*. Pursuant to the Electricity Act, 1998 (Ontario) (EA), the Company is required to compute taxes under the ITA and *Taxation Act, 2007* and remit such amounts thereunder computed to the Ministry of Finance (Ontario).

The Company provides for PILs using the asset and liability method. Under this method, future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A future income tax asset recognized shall be limited to the amount that is more likely than not to be realized.

Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the Company at that time.

PILs recoverable from loss carry forwards are recorded in future payments in lieu of taxes on the balance sheet using the substantively enacted rates at the balance sheet date expected to apply when recovery of the loss carry forwards are expected to be recovered.

Customer and developer deposits

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

2. Significant accounting policies (continued)

Asset retirement obligations

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

Use of estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements including changes as a result of future regulatory decisions.

Accounts receivable, unbilled revenue and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate valuation allowance. Inventory is recorded net of provisions for obsolescence. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

Revenue recognition

Revenue is recognized on the accrual basis, which includes an estimate of unbilled revenue. Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis on power used. Any discrepancies in the revenue collected and the associated cost of power to distribute are charged to regulatory assets.

Financial instruments

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

The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Unbilled revenue	Loans and receivables
Bank loan	Other liabilities
Accounts payable and accrued liabilities	Other liabilities
Promissory note	Other liabilities
Customers’ and developers’ deposits	Other liabilities

<u>*Held for trading*</u>

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

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

2. Significant accounting policies (continued)

Financial instruments (continued)

Loans and receivables

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

Other liabilities

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

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

Derivatives

The Company does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the presentation of these financial statements.

Future changes in accounting policies

International financial reporting standards (IFRS)

On February 13, 2008 the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the Company will apply IFRS to its financial statements for the year ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The Company continues to assess the impact of conversion to IFRS on its results of operations.

3. Capital assets and intangibles

			2010	2009
	Cost	Accumulated amortization	Net book value	Net book value
	$	$	$	$
Land	**111,556**	**-**	**111,556**	111,556
Buildings	**755,680**	**343,794**	**411,886**	355,529
Distribution stations	**143,555**	**143,555**	**-**	-
Distribution plant	**26,220,748**	**12,014,907**	**14,205,841**	13,653,374
General equipment and intangibles	**1,753,443**	**1,403,691**	**349,752**	388,301
Capital contribution	**(4,977,193)**	**(1,205,453)**	**(3,771,740)**	(3,103,478)
	24,007,789	**12,700,494**	**11,307,295**	11,405,282

Intangible assets, representing computer software, is included in general equipment and intangibles and has an original cost of $467,221 (2009 - $434,101) and an accumulated amortization of $269,059 (2009 - $196,840). Amortization expense on intangible assets totaled $72,219 (2009 - $6,111).

During the year, the Company received $153,456 (2009 – $130,482) of capital contributions in aid of construction.

4. Bank loan

The Company has available the following credit facilities with the bank:

- $1,000,000 operating loan to finance working capital, bearing interest at prime rate plus 0%, due on demand
- $964,845 letter of credit to satisfy IESO Prudential requirement, bearing interest at 0.6%, due on demand
- $1,600,000 operating demand loan to assist with 2010 capital expenditures, bearing interest at prime rate plus 0%, due on demand
- $1,600,000 committed reducing term loan by way of fixed rate term loan and floating rate term loan, fixed rate loan bearing interest at market rate as determined by the bank, floating rate loan bearing interest at prime rate plus 0.5%, fixed rate loan term up to 5 years, floating rate loan term up to 1 year

The credit facilities are secured by a General Security Agreement, assignment of fire insurance on inventory and equipment, assignment of liability insurance, and Postponement Agreement executed by the bank, the Company and the Town of Grimsby.

At December 31, 2010, the amount drawn on the credit facilities totaled $1,600,000 (2009 – nil).

5. Promissory note

The promissory note matures on February 1, 2020 and is payable to the Town of Grimsby. The note bears interest at the rate of 7.25% per annum.

6. Regulatory assets/liabilities

	2010	2009
	$	$
Regulatory assets (liabilities)		
Settlement variances	**(701,049)**	(1,158,850)
Smart meters	**1,555,537**	114,496
Regulatory assets recovery amount	**(361)**	19,329
	854,127	(1,025,025)

Net regulatory assets (liabilities) represent amounts recovered from customers in excess of costs incurred at OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future settlement in electricity distribution rates. Management assesses the future uncertainty with respect to the recovery of those amounts, and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision concerning adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Regulatory assets (liabilities) incur interest at prescribed rates. In 2010, the rates ranged from 0.55% to 1.2% (2009 – 0.55% to 2.45%).

Settlement variances – represent amounts that have accumulated since Market Opening and comprise:

(a) Variances between amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the wholesale electricity market and grid, various wholesale market settlement charged and transmission charges, and the amounts billed to customers by the Company based on the OEB approved wholesale market service rate; and,

(b) Variances between the amounts charged by the IESO for energy commodity costs and the amounts billed to customers by the Company based on OEB approved rates.

Smart meters – The Province of Ontario has committed to have "Smart Meter" electricity meters installed in certain homes and small businesses by the end of 2008 and throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals. Bill 21, Energy Conservation and Responsibility Act, provides the legislative framework and regulations to support this initiative.

Included in distribution rates, effective May 1, 2006, is a charge for smart meters of $1.00 (2009 - $0.27) per metered customer per month. Consistent with the OEB's direction and pending further guidance, all smart meter related expenditures and recoveries are currently being deferred in regulatory accounts.

Regulatory assets recovery amount – represents costs incurred by the Company as of December 31, 2004 which have been approved for recovery through rates net of amounts recovered from customers.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates that the Company may charge and the costs that the Company may recover, including the balance of its regulatory assets.

In the absence of rate regulation, Canadian generally accepted accounting principles would require the Company to record the costs and recoveries described above in the operating results of the year in which they are incurred and reported earnings before income taxes would be $1,825,762 lower (2009 - $337,788 lower) than reported.

6. Regulatory assets/liabilities (continued)

Rate regulation

The Company is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the Ontario Energy Board Act (1998). The OEB has the power and responsibility to approve or fix rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

In January 2000, the OEB established that distribution rates would be subject to Performance Based Regulation ("PBR"), a method of regulation whereby distribution rates are reduced annually to reflect productivity improvements required on the Company. Under this rate methodology, rates also include regulated amounts for return on Company equity and debt, which were initially determined by the OEB to be 9.88% and 7.25%, respectively. While the initial PBR regulatory framework provided for those regulatory rates of return, subsequent regulation and Provincial Government initiatives prevented distribution companies from fully achieving the theoretical rate of return on equity.

In 2005, the Company filed rate applications to adjust its distribution charges to provide for the full theoretical regulatory rate of return of 9.88% and continued recovery of its regulatory assets. As mandated by the OEB, the rate increase is subject to a financial commitment by the Company to invest $221,745 in conservation and demand management activities over the period July 1, 2004 to April 30, 2008. Spending on this program was completed in 2008.

In 2006, the OEB approved the Company's 2006 distribution rates providing for a revised rate of return of 9% effective May 1, 2006.

7. Payments in lieu of taxes

The Company's income tax expense for the year ended December 31, 2010 consists of the following:

Temporary differences which give rise to future payments in lieu of tax assets and liabilities are as follows:

	2010	2009
	$	$
Allowance for doubtful accounts	**2,382**	2,167
Property, plant and equipment	**1,010,942**	979,021
Regulatory liabilities	**40,442**	138,671
Future payments in lieu of tax assets	**1,053,766**	1,119,859

7. Payments in lieu of taxes (continued)

The impact of differences between the Company's reported payments in lieu of corporate income taxes and the expense that would otherwise result from the application of the combined statutory income tax rate of 31% (2009 – 33%) is as follows:

	2010	2009
	$	$
Basic taxes applied to income before PILs	**140,074**	161,831
Increase (decrease) in PILs resulting from:		
Tax basis of depreciable capital assets and goodwill in excess of accounting basis	**-**	(20,887)
Change in future tax rate	**11,019**	131,123
Change in regulatory liabilities	**(32,136)**	(111,470)
Prior year adjustments	**58,563**	(32,043)
Other	**2,871**	1,944
	180,391	130,498

8. Change in non-cash working capital

	2010	2009
	$	$
Cash provided by (used in)		
Accounts receivable		
Service revenue	**89,437**	(58,019)
Other	**(88,007)**	(168,789)
Due to/from related parties	**43,743**	41,834
Unbilled revenue	**102,484**	138,914
Inventory	**45,909**	3,325
Prepaid expenses	**52,580**	57,514
Accounts payable and accrued liabilities	**43,241**	38,697
Payments in lieu of taxes payable/receivable	**(132,938)**	(198,694)
	156,449	(145,218)

The Company acquired property and equipment through non-cash capital contributions of $713,887 (2009 - $42,674).

During the year, the Company received (refunds)/made payments in lieu of taxes in the amount of $51,045 (2009 – $227,407).

9. Related party transactions

The following transactions have been made with the parent company, shareholder of the parent company and a subsidiary of the parent company:

	2010	2009
	$	$
Revenue		
Service Revenue	**389,702**	348,991
Other	**44,861**	18,357
Expenses		
Interest charges	**419,249**	419,249
Other expenses	**48,409**	39,930
Connection fees	**380,511**	369,666
Management fees	**11,000**	186,525

These transactions have taken place in the ordinary course of business and are recorded at the exchange amount.

Included in accounts receivable are $12,436 (2009 - $9,440) owing from related parties and included in accounts payable are $492,378 (2009 – $459,962) owing to related parties. These balances are non-interest bearing with no fixed terms of repayment.

During 2009, the Company migrated its billing system to a SAP platform. The Company has a contractual commitment to pay $3,500 per month for system administration and non-system related support to this related party.

10. Pension agreements

The Company makes contributions to the Ontario Municipal Employees Retirement System ("OMERS"), which is a multi-employer plan, on behalf of its full-time staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by an employee based on the length of services and rate of pay.

Contributions during the year were 6.4% (2009 – 6.5%) for employee earnings below the year's maximum pensionable earnings and 9.7% (2009 – 9.6%) thereafter.

The amount contributed in 2010 is $76,319 (2009 – $63,503) and is included as an expenditure in the Statement of Earnings.

11. 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 should losses be experienced by MEARIE, for the years in which the company and its predecessor company was a member.

To December 31, 2010, the Company has not been made aware of any additional assessments. Participation in MEARIE covers a one year underwriting period which expires January 1, 2011. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next underwriting term.

12. Commitments and contingent liabilities

A letter of credit in the amount of $1,464,704 has been issued in favour of the Independent Electricity System Operator ("IESO") as security for the Company's purchase of electricity through the IMO. No amounts were drawn down on the letter of guarantee at year-end.

13. Capital disclosures

The main objectives of the Company when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

As at December 31, 2010, the Company's definition of capital includes shareholder's equity and promissory note. This definition remains unchanged from prior years. As at December 31, 2010, shareholder's equity amounts to $6,220,385 (2009 - $5,891,158) and promissory note amounts to $5,782,746 (2009 - $5,782,746). The Company's capital structure as at December 31, 2010 is 48% debt and 52% equity (2009 – 50% debt and 50% equity). There have been no changes in the Company's approach to capital management during the year.

The Company has customary covenants typically associated with long-term debt. The Company is in compliance with all credit agreement covenants and limitations associated with its long-term debt.

14. Financial instruments and risk management

The Company, through its financial assets and liabilities, has exposure to liquidity and credit risks.

Liquidity risk

The Company's objective is to have sufficient liquidity to meets its liabilities when due. The Company monitors its cash balance and cash flows generated from operations to meet its requirements.

Credit risk

Financial instruments are exposed to credit risk as a result of the counter-party defaulting on its obligations. However, the Company has a large number of diverse customers minimizing concentration of credit risk. The Company requires customers to provide security deposits subject to OEB regulations.

Fair value

The carrying values of cash, accounts receivable, due to/from related parties, bank loan, and accounts payable and accrued liabilities approximate their fair values due to the immediate or short-term maturity of these financial instruments.

Customer and developer deposits have a fair value that approximates carrying value. Interest is paid on deposits on a monthly basis at a market rate, as directed by the Ontario Energy Board.

The promissory note payable to the Town of Grimsby is valued at its face value. It is not practicable within constraints of timeliness or cost to reliably measure its fair value.

15. Comparative figures

Certain of the comparative figures have been reclassified to conform to current year presentation.

Appendix 1.4 Copy of Grimsby Power Inc.'s 2011 Pro Forma Financial Statements

Grimsby Power Inc.

2011 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	2,181,886
1010-Cash Advances and Working Funds	150
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	681,500
1102-Accounts Receivable - Services	(25,000)
1104-Accounts Receivable - Recoverable Work	30,000
1105-Accounts Receivable - Merchandise, Jobbing, etc.	45,000
1110-Other Accounts Receivable	100,000
1120-Accrued Utility Revenues	1,650,000
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(6,500)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0

1170-Notes Receivable	0
1180-Prepayments	45,000
1190-Miscellaneous Current and Accrued Assets	9,000
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**4,711,036**

1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	300,000
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**300,000**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0

1460-Other Non-Current Assets	0
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**0**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	90,000
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	(35,000)
1521-Special Purpose Charges	500
1525-Miscellaneous Deferred Debits	1,245
1530-Deferred Losses from Disposition of Utility Plant	0
1532-Renewable Connections	41,191
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0

1548-RCVA - Service Transaction Request (STR)	30,000
1550-LV Charges - Variance	(110,000)
1555-Smart Meters Recovery	1,611,352
1556-Smart Meters OM & A	273,266
1562-Deferred PILs	(211,045)
1563-Deferred PILs - Contra	211,045
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(255,000)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	(50,000)
1586-RSVA - Connection Charges	(195,000)
1588-RSVA - Commodity (Power)	250,000
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	(1,081,188)
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	(188,000)
1200-Other Assets and Deferred Charges Total	**383,366**

1450-Distribution Plant	
1805-Land	0
1806-Land Rights	0
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	143,555
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	7,977,543
1835-Overhead Conductors and Devices	2,331,300
1840-Underground Conduit	5,125,882
1845-Underground Conductors and Devices	1,924,858
1850-Line Transformers	7,752,700
1855-Services	1,959,521
1860-Meters	1,868,477
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**29,083,836**

1500-General Plant	
1905-Land	111,556
1906-Land Rights	0
1908-Buildings and Fixtures	832,921

1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	137,239
1920-Computer Equipment - Hardware	140,678
1925-Computer Software	689,721
1930-Transportation Equipment	764,820
1935-Stores Equipment	47,086
1940-Tools, Shop and Garage Equipment	156,678
1945-Measurement and Testing Equipment	75,448
1950-Power Operated Equipment	0
1955-Communication Equipment	10,669
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(5,127,193)
1500-General Plant Total	**(2,160,375)**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0

2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**0**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(13,852,471)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(13,852,471)**

Total Assets	**18,465,391**

1650-Current Liabilities

2205-Accounts Payable	350,000
2208-Customer Credit Balances	0
2210-Current Portion of Customer Deposits	0
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	3,039,575
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	20,000
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	100,000
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	106,667
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	419,249
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	0
2292-Payroll Deductions / Expenses Payable	25,000
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	0

2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**4,060,491**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	0
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	300,000
2340-Collateral Funds Liability	350,000
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	(981,188)
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0
2435-Accrued Rate-Payer Benefit	0

1700-Non-Current Liabilities Total	**(331,188)**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	5,782,746
2525-Term Bank Loans - Long Term Portion	2,886,667
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**8,669,413**

1850-Shareholders' Equity	
3005-Common Shares Issued	5,782,747
3008-Preference Shares Issued	0
3010-Contributed Surplus	70,721
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0

3045-Unappropriated Retained Earnings	125,449
3046-Balance Transferred From Income	87,759
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**6,066,676**

Total Liabilities & Shareholder's Equity	**18,465,391**

Balance Sheet Total	0

Grimsby Power Inc.
2010 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(5,967,214)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	(5,882,989)
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(5,000)
4030-Sentinel Energy Sales	0
4035-General Energy Sales	(28,228)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	(1,500,000)
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,227,133)
4064-Billed WMS-One Time	0
4066-NS	(1,086,615)

4068-CS	(884,919)
4075-LV Charges	(130,000)
3000-Sales of Electricity Total	**(16,712,098)**
3050-Revenues From Services - Distribution	
4080-Distribution Services Revenue	(3,435,689)
4082-RS Rev	(21,300)
4084-Serv Tx Requests	(600)
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(3,457,589)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(65,000)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(55,000)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(55,000)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(175,000)**
3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	(100,000)
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(98,600)

4380-Expenses of Non-Utility Operations	95,000
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(2,000)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(105,600)**
3200-Investment Income	
4405-Interest and Dividend Income	(25,000)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(25,000)**
3350-Power Supply Expenses	
4705-Power Purchased	13,383,430
4708-WMS	1,227,133
4710-Cost of Power Adjustments	0
4712-	0
4714-NW	1,086,615
4715-System Control and Load Dispatching	0
4716-CN	884,919
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	0
4750-LV Charges	130,000
3350-Power Supply Expenses Total	**16,712,098**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	63,825
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	0
5020-Overhead Distribution Lines and Feeders - Operation Labour	28,427
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	9,650
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	0
5040-Underground Distribution Lines and Feeders - Operation Labour	32,874

5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	0
5070-Customer Premises - Operation Labour	4,687
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	106,903
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	25,500
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**271,866**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	55,325
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	800
5120-Maintenance of Poles, Towers and Fixtures	64,082
5125-Maintenance of Overhead Conductors and Devices	99,159
5130-Maintenance of Overhead Services	40,193
5135-Overhead Distribution Lines and Feeders - Right of Way	40,268
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	0
5155-Maintenance of Underground Services	11,162
5160-Maintenance of Line Transformers	93,164
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	14,232
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**418,385**
3650-Billing and Collecting	
5305-Supervision	4,660
5310-Meter Reading Expense	87,665
5315-Customer Billing	357,358
5320-Collecting	42,935
5325-Collecting - Cash Over and Short	0

5330-Collection Charges	5,906
5335-Bad Debt Expense	6,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**504,524**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	12,000
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
5515-Advertising Expense	4,500
3700-Community Relations Total	**16,500**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	145,260
5610-Management Salaries and Expenses	211,280
5615-General Administrative Salaries and Expenses	172,430
5620-Office Supplies and Expenses	32,325
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	47,920
5635-Property Insurance	22,000
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	5,880
5650-Franchise Requirements	0
5655-Regulatory Expenses	26,500
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses	88,790
5670-Rent	0
5675-Maintenance of General Plant	80,885
5680-Electrical Safety Authority Fees	5,000
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**838,270**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	1,025,789
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0

5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**1,025,789**
3900-Interest Expense	
6005-Interest on Long Term Debt	422,850
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	102,487
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**525,337**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	27,000
3950-Taxes Other Than Income Taxes Total	**27,000**
4000-Income Taxes	
6110-Income Taxes	43,786
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**43,786**
4100-Extraordinary & Other Items	
6205-Donations	3,974
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**3,974**
Net Income - (Gain)/Loss	**(87,759)**

Appendix 1.5 Copy of Grimsby Power Inc.'s 2012 Pro Forma Financial Statements

2012 BALANCE SHEET - IFRS

Account Description	Total
1050-Current Assets	
1005-Cash	361,878
1010-Cash Advances and Working Funds	150
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	666,500
1102-Accounts Receivable - Services	(30,000)
1104-Accounts Receivable - Recoverable Work	30,000
1105-Accounts Receivable - Merchandise, Jobbing, etc.	58,000
1110-Other Accounts Receivable	100,000
1120-Accrued Utility Revenues	2,000,000
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(6,500)
1140-Interest and Dividends Receivable	0

1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	85,000
1190-Miscellaneous Current and Accrued Assets	12,000
1200-Accounts Receivable from Associated Companies	0
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**3,277,028**

1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	250,000
1340-Merchandise	0
1350-Other Material and Supplies	0
1100-Inventory Total	**250,000**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0

1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	0
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**0**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	175,000
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	(45,000)
1521-Special Purpose Charges	500
1525-Miscellaneous Deferred Debits	1,245
1530-Deferred Losses from Disposition of Utility Plant	0
1532-Renewable Connections	68,388
1540-Deferred Losses from Disposition of Utility Plant	0

1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	35,000
1550-LV Charges - Variance	(135,000)
1555-Smart Meters Recovery	400,564
1556-Smart Meters OM & A	0
1562-Deferred PILs	(211,045)
1563-Deferred PILs - Contra	211,045
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(350,000)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	(75,000)
1586-RSVA - Connection Charges	(180,000)
1588-RSVA - Commodity (Power)	250,000
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	(1,081,188)
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	(188,000)
1200-Other Assets and Deferred Charges Total	**(1,123,492)**

1450-Distribution Plant	
1805-Land	0
1806-Land Rights	0
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	143,555
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	8,042,983
1835-Overhead Conductors and Devices	2,479,954
1840-Underground Conduit	4,305,456
1845-Underground Conductors and Devices	1,294,786
1850-Line Transformers	6,323,040
1855-Services	487,377
1860-Meters	1,736,662
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**24,813,813**

1500-General Plant	
1905-Land	111,556
1906-Land Rights	0

1908-Buildings and Fixtures	915,491
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	137,239
1920-Computer Equipment - Hardware	158,528
1925-Computer Software	714,671
1930-Transportation Equipment	1,063,820
1935-Stores Equipment	47,086
1940-Tools, Shop and Garage Equipment	158,278
1945-Measurement and Testing Equipment	75,448
1950-Power Operated Equipment	0
1955-Communication Equipment	34,369
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	0
1500-General Plant Total	**3,416,488**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0

2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**0**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(14,561,570)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(14,561,570)**

Total Assets	**16,072,267**

1650-Current Liabilities	
2205-Accounts Payable	350,000
2208-Customer Credit Balances	0
2210-Current Portion of Customer Deposits	0
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	810,503
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	15,000
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	100,000
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	206,667
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	419,249
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	0
2292-Payroll Deductions / Expenses Payable	25,000

2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	0
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**1,926,419**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	0
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	87,569
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	325,000
2340-Collateral Funds Liability	150,000
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	(981,188)
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	0

2435-Accrued Rate-Payer Benefit	0
1700-Non-Current Liabilities Total	**(418,619)**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	5,782,746
2525-Term Bank Loans - Long Term Portion	2,493,333
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**8,276,079**

1850-Shareholders' Equity	
3005-Common Shares Issued	5,782,747
3008-Preference Shares Issued	0
3010-Contributed Surplus	70,721
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0

3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	280,184
3046-Balance Transferred From Income	154,736
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**6,288,388**

Total Liabilities & Shareholder's Equity	**16,072,267**

Balance Sheet Total	0

2012 STATEMENT OF INCOME AND RETAINED EARNINGS - IFRS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(6,052,197)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	(5,974,712)
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(5,000)
4030-Sentinel Energy Sales	0
4035-General Energy Sales	(27,288)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	(1,500,000)
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,243,399)
4064-Billed WMS-One Time	0

4066-NS	(1,237,952)
4068-CS	(986,265)
4075-LV Charges	(130,000)
3000-Sales of Electricity Total	**(17,156,811)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(3,651,176)
4082-RS Rev	(25,591)
4084-Serv Tx Requests	(800)
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(3,677,567)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(65,000)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	0
4225-Late Payment Charges	(55,000)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(55,000)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(175,000)**
3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	(100,000)
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0

4375-Revenues from Non-Utility Operations	(98,600)
4380-Expenses of Non-Utility Operations	95,000
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(5,000)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(108,600)**
3200-Investment Income	
4405-Interest and Dividend Income	(25,000)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(25,000)**
3350-Power Supply Expenses	
4705-Power Purchased	13,559,196
4708-WMS	1,243,399
4710-Cost of Power Adjustments	0
4712-	0
4714-NW	1,237,952
4715-System Control and Load Dispatching	0
4716-CN	986,265
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	0
4750-LV Charges	130,000
3350-Power Supply Expenses Total	**17,156,811**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	60,649
5010-Load Dispatching	0
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	0
5020-Overhead Distribution Lines and Feeders - Operation Labour	37,599
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	12,010
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	0

5040-Underground Distribution Lines and Feeders - Operation Labour	31,158
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	0
5070-Customer Premises - Operation Labour	4,701
5075-Customer Premises - Materials and Expenses	0
5085-Miscellaneous Distribution Expense	306,291
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	25,758
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**478,166**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	51,441
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	816
5120-Maintenance of Poles, Towers and Fixtures	40,114
5125-Maintenance of Overhead Conductors and Devices	82,836
5130-Maintenance of Overhead Services	67,233
5135-Overhead Distribution Lines and Feeders - Right of Way	77,653
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	0
5155-Maintenance of Underground Services	13,817
5160-Maintenance of Line Transformers	78,586
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	48,178
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**460,674**
3650-Billing and Collecting	
5305-Supervision	4,284
5310-Meter Reading Expense	166,644
5315-Customer Billing	360,711

5320-Collecting	43,983
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	6,630
5335-Bad Debt Expense	6,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**588,252**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	9,000
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
5515-Advertising Expense	3,500
3700-Community Relations Total	**12,500**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	159,420
5610-Management Salaries and Expenses	228,940
5615-General Administrative Salaries and Expenses	226,219
5620-Office Supplies and Expenses	44,694
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	86,856
5635-Property Insurance	23,307
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	5,998
5650-Franchise Requirements	0
5655-Regulatory Expenses	59,520
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses	99,401
5670-Rent	0
5675-Maintenance of General Plant	113,093
5680-Electrical Safety Authority Fees	5,100
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**1,052,548**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	709,099
5710-Amortization of Limited Term Electric Plant	0

5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**709,099**
3900-Interest Expense	
6005-Interest on Long Term Debt	443,322
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	118,894
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**562,216**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	27,540
3950-Taxes Other Than Income Taxes Total	**27,540**
4000-Income Taxes	
6110-Income Taxes	(63,681)
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**(63,681)**
4100-Extraordinary & Other Items	
6205-Donations	4,117
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**4,117**
Net Income - (Gain)/Loss	**(154,736)**

Exhibit 2 Rate Base

OVERVIEW

The rate base used for the purpose of calculating the revenue requirement used in this Application follows the definition used in the 2006 EDR Handbook as an average of the balances at the beginning and the end of the 2012 Test Year (MIFRS), plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses.

Modified IFRS refers to IFRS accounting as modified for regulatory purposes consistent with the Report of the Board, Transition to IFRS dated July 28, 2009 (EB-2008-0408) and the Addendum to Report of the Board issued on June 13, 2011.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. Grimsby Power Inc. does not have any non-distribution assets in rate base. Controllable expenses include operations and maintenance, billing & collecting and administration expenses. Grimsby Power Inc. has calculated its 2012 Test Year Rate Base as $16,336,952.

Grimsby Power Inc. has provided a summary of its rate base calculations for the years Actual, 2006 Board Approved, 2007 to 2010 Actual, 2011 Bridge Year, 2012 Test Year (CGAAP) and 2012 Test Year (MIFRS) in Table 2.1 below.

Table 2.1 Summary of Rate Base

Description	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 CGAAP Test Year	2012 IFRS Test Year
Gross Fixed Assets	18,469,627	20,923,713	21,816,540	22,752,308	23,814,394	24,003,049	26,923,461	28,241,110	28,230,301
Accumulated Depreciation	8,227,766	10,190,021	10,951,970	11,823,433	12,409,113	12,700,493	13,852,471	14,988,455	14,561,570
Net Book Value	10,241,861	10,733,692	10,864,570	10,928,875	11,405,281	11,302,556	13,070,990	13,252,655	13,668,731
Average Net Book Value	10,241,861	10,719,193	10,799,131	10,896,722	11,167,078	11,353,918	12,186,773	13,161,823	13,369,860
Working Capital	12,584,317	14,326,168	15,218,415	14,917,198	15,206,163	17,156,886	18,792,616	19,616,788	19,780,608
Working Capital Allowance	1,887,647	2,148,925	2,282,762	2,237,580	2,280,924	2,573,533	2,818,892	2,942,518	2,967,091
Rate Base	12,129,508	12,868,118	13,081,893	13,134,302	13,448,002	13,927,451	15,005,665	16,104,341	16,336,952

Grimsby Power Inc.'s capital investment in distribution plant has averaged $1.40 million per year (2004-2010) and $1.42 million per year (2006-2010) (averages do not include investments in smart meters) which accounts for the year over year variance in Average Net Book Value. As discussed throughout this application and Grimsby Power Inc's Distribution Asset Management Plan (DAMP), filed as Appendix 2.1 to this Exhibit, the most significant drivers for capital investment are the retirement of 4.16kV and 8.32kV distribution stations and customer driven investments. Drivers are discussed in more detail throughout this Exhibit.

Grimsby Power Inc. has provided a summary of its cost of power and controllable expenses used in calculating working capital for the period 2004- 2005 Actual, 2006 Board Approved, 2006 Actual to 2010 Actual, 2011 Bridge Year, 2012 Test Year (CGAAP), and 2012 Test Year (MIFRS) in Table 2.2 below. Details of Grimsby Power Inc.'s calculation of working capital allowance are provided further in this Exhibit.

ALLOWANCE FOR WORKING CAPITAL

Table 2.2 Summary of Working Capital Calculation

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 CGAAP Test Year	2012 IFRS Test Year
Cost of Power	11,033,351	12,816,602	13,500,381	13,124,063	13,435,689	15,351,169	16,712,098	17,156,811	17,156,811
Operations	207,528	187,438	187,089	200,472	197,350	179,324	271,866	283,721	478,166
Maintenance	219,107	225,316	271,420	409,935	380,246	397,852	418,385	489,114	460,674
Billing & Collecting	399,757	407,642	483,317	487,755	463,965	506,789	504,524	590,270	588,252
Community Relations	5,388	53,288	80,754	33,426	11,428	11,749	16,500	12,500	12,500
Administrative & General Expenses	690,965	599,394	663,462	634,397	687,172	684,872	838,270	1,052,715	1,052,548
Other - LEAP program							3,974	4,117	4,117
Taxes Other than Income Taxes	28,221	36,488	31,990	27,150	30,314	25,130	27,000	27,540	27,540
Working Capital	12,584,317	14,326,168	15,218,415	14,917,198	15,206,163	17,156,886	18,792,616	19,616,788	19,780,608
Working Capital Allowance - 15%	1,887,648	2,148,925	2,282,762	2,237,580	2,280,924	2,573,533	2,818,892	2,942,518	2,967,091

The changes in working capital are primarily attributed to the annual changes in Cost of Power resulting from growth, weather and changes in the market price of electricity and increases in OM&A expenditures as detailed in Exhibit 4. Grimsby Power Inc. has not completed a lead-lag study for this application as per OEB direction. The working capital allowance is based on 15% of cost of power and controllable expenses in accordance with the Filing Requirements and consistent with OEB Decisions on other distribution rate applications where a utility specific lead-lag study had not been completed.

In support of its rate base calculation, Grimsby Power Inc. has included details of its Gross Assets, Accumulated Depreciation, Working Capital and Fixed Asset Continuity Schedules for 2006 Actual to 2012 Test Year as required in the Filing Requirements.

TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

The bulk of Grimsby Power Inc.'s deployment of smart meters occurred in 2010 with a mass deployment using a third party service provider. The remaining meters are scheduled to be completed by the end of 2011 to coincide with the transition to time of use rates as of December 31, 2011. The stranded meters costs were recorded in the smart meter variance subaccount 1555. The stranded meter costs were calculated as the pooled net book value cost of removed meters. The older meters were retired earlier than planned and the cost associated with the retired meters was not been fully depreciated. In accordance with the direction given in the Chapter 2 Filing Requirements Grimsby Power Inc. has decided to propose a recovery of its stranded meter assets over a one year period through the use of a Rate Rider specifically for this purpose.

CAPITAL EXPENDITURES

Overview

In managing its distribution system assets, Grimsby Power Inc.'s main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations. Grimsby Power Inc. is committed to providing our customers with an economical, safe, reliable supply of electricity and helping the Town of Grimsby become one of the most energy efficient communities in Ontario. Grimsby Power Inc.'s Distribution Asset Management Plan, which sets out Grimsby Power Inc.'s processes for determining the necessary distribution system investments to ensure safe, reliable delivery of electricity to its customers, accompanies this Exhibit as Appendix 2.1.

The Budget process at Grimsby Power Inc. is an integral planning tool and ensures that appropriate resources are available to maintain and grow its capital infrastructure. It is the responsibility of each department to contribute in the preparation of the Capital and OM&A Budget with the assistance of the Finance Department. The responsibility of the Finance department is to coordinate the budget process and produce financial statements which are reflective of the forecasted budget. Once the management team and CEO are comfortable with the budget it is presented to the Board of Directors - Budget and Audit Committee for approval. Once approved by committee it is presented to the Board of Directors for final approval.

Once the Board of Directors approve the annual budget the budget amounts do not change but rather provide a plan against which actual results may be evaluated.

Capital Budget – Distribution System Assets

Grimsby Power Inc's capital budget is divided into the following sub-categories:

- Conversion to 27.6kV
- Customer Driven
- Pole Replacement Program
- Pad-Mount Transformer Replacement Program
- Silicone Injection of Underground Primary Cables
- Regulatory Requirements

A detailed description of each of these categories is provided as follows:

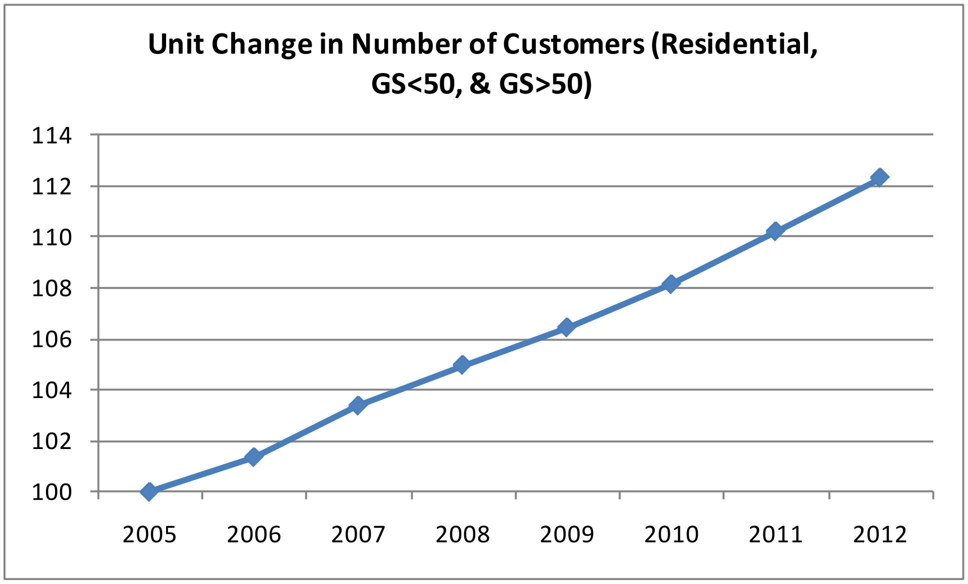
Conversion to 27.6kV

The largest portion of Grimsby Power Inc.'s capital expenditures has been on Conversion to 27.6kV. In 1989 the then Grimsby Hydro Electric Commission adopted an ambitious plan to rebuild the entire distribution system over a 25 year period. At the time, a policy was adopted to improve system reliability by converting 4.16kV and 8.32kV distribution systems to 27.6kV. The 4.16kV and 8.32kV was supplied through a number of distribution substations that were approaching end of life. The distribution system fed from the oldest stations in an area below the Niagara escarpment was converted first (Phase I). This work took place from 1990 to 2002. The next phase of the plan (Phase II) was to convert the area above the escarpment. This work was planned to take place from 2002 to approximately 2012. In the midst of Phase II, known capacity issues peaked at the Beamsville TS owned by Hydro One. The solution to this issue resulted in a new Transformer Station being built on the escarpment known as the Niagara West Transformer Station owned by an affiliate company Niagara West Transformer Corporation. Two feeders from the station supply Grimsby Power Inc. and the conversion work set in Phase II of the rebuild plan were focused on loading these two feeders and at the same time unloading the constrained feeders at Beamsville TS.

Customer Driven

The Town of Grimsby has grown steadily over the last several years. This growth requires significant investment in distribution plant in order to service the new customers. Grimsby Power Inc. had 9350 metered customers in 2005 which has increased to 10,061 metered customers by the end of 2010 and forecasted to reach 10,486 by the end of the 2012 Test Year. This represents a growth rate in the 2% per year range and it is expected this will continue into the test year. This growth is shown in Chart 2.1 below with the base year set in 2005 at 100% (unit value of 1).

Chart 2.1 Unit Change in Number of Customers



Customer driven projects are those projects that Grimsby Power Inc. undertakes to meet customer obligations in accordance with the OEB's Distribution System Code (the "DSC") and Grimsby Power Inc.'s Conditions of Service. Activities include connecting new residential & general service customers and constructing distribution plant to connect new subdivisions. Grimsby Power Inc. contributes to the cost of these projects using the economic evaluation methodology in accordance with the DSC and the provisions of its Conditions of Service for system expansions to determine the level of capital contribution.

Pole and Pad-Mount Transformer Replacement Program

Replacement projects are completed when it has been determined through proper condition assessment that assets have reached their end of useful life. Grimsby Power Inc. completes visual inspections of its plant and performs predictive testing on certain assets where such testing is warranted, and replaces assets based on inspection and testing results as asset conditions are determined. Generally, assets identified in one year are scheduled for replacement in the following year. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

Poles are replaced when the strength of the wood (usually at the ground level) is no longer capable of withstanding the extreme weather conditions for which they were designed or if any visible portion of the pole is compromised.

Pad-mounted transformers are subject to corrosion where the metal tank comes in contact with the concrete support foundation. Grimsby Power Inc. has noticed a trend in the cases, tanks, or both corroding to the point where the case is penetrable or the tank is seeping oil. When such a condition is identified the pad-mount transformer is scheduled for replacement.

Silicone Injection of Underground Primary Cables

Underground primary cable is subject to an aging process which depending on the age of the cable may lead to premature failure. Much of this degradation is caused by a process called water treeing. Silicone injection of underground primary cables has been performed for utilities since the mid 1980's and has proven successful in increasing the life expectancy of cable by 20 years or more. Grimsby Power Inc. adopted this life extension technology in 2004. Grimsby Power Inc. is one of only a few Ontario LDC's utilizing this life extension technology. Each year a section of the distribution system is targeted for this cable restorative process.

Regulatory Requirements

These projects are capital investments which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy (and its predecessors) or the Ministry of Environment. In 2006, The Government of Ontario established targets for the installation of 800,000 smart electricity meters by December 31, 2008 and the installation of smart meters for all Ontario customers by December 31, 2010. In keeping with this directive Grimsby Power Inc. began installing smart meter communications infrastructure in 2009 and performed a mass deployment of meters in 2010.

Grimsby Power Inc. is scheduled to complete 100% of the deployment of Smart Meters as approved by Ontario Regulation 427/06 by the end of 2011. To date as of March 31, 2011 Grimsby Power Inc. is 98% complete. Smart Meter capital is currently recorded in the smart meter variance account 1555. Grimsby Power Inc. is proposing the disposition on its smart meter variance accounts in this Application through the use of a Rate Rider.

The Distribution System Code specifies the elimination of long term load transfers (LTLT). Currently the distribution system code specifies that such arrangements be finalized by June 30, 2014. Grimsby Power Inc. began the process of building the distribution system to connect all customers within Grimsby Power Inc.'s service territory to its distribution system in approximately 2002. This process was completed in 2010. Grimsby Power Inc.'s "Elimination of Long Term Load Transfer Plan" was updated with the OEB in December 2010. A permanent exchange of customers with Niagara Peninsula Energy Inc. will finalize all LTLT situations. There are 10 customers who will be transferred to Niagara Peninsula Energy Inc. and 6 customers who will be transferred to Grimsby Power Inc. The application process is scheduled to take place in 2011.

Capital Budget-General Plant Assets

Other Capital Expenditures are general assets relating to Office Furniture and Equipment, Communications Equipment, Computer Hardware and Software, Vehicles and Miscellaneous Tools and Equipment.

General plant capital projects are as follows:

- Buildings and Fixtures - USoA 1908
- Office Furniture & Equipment - USoA 1915

- Computer Equipment Hardware - USoA 1920
- Computer Software - USoA 1925
- Transportation Equipment - USoA 1930
- Tools, Shop, and Garage Equipment - USoA 1940
- Measurement and Test Equipment – UsoA 1945
- Communication Equipment - USoA 1955

Capitalization Policy

Grimsby Power Inc. does not have a formal written capitalization policy. Grimsby Power Inc. follows Generally Accepted Accounting Principles, in particular the CICA Handbook Section 3060, Capital Assets as well as the guidelines as set out in the OEB Accounting Procedure Handbook. Existing business processes are as follows:

- The amount to be capitalized is the cost to acquire or construct a capital asset, including ancillary costs incurred to place a capital asset into its intended use. Grimsby Power Inc. does not capitalize interest on funds used during construction as capital projects are budgeted for and completed generally within six months.

- Assets that are intended to be used on an ongoing basis and are expected to provide future economic benefit (generally considered to be greater than one year) will be capitalized.

- Individual items with an estimated useful life greater than one year and valued at greater than $500 will be capitalized.

- Expenditures that create a physical betterment or improvement of the asset will be capitalized.

- With respect to transportation equipment all costs associated with placing the equipment into service are capitalized.

- Spare transformers and meters are accounted for as capital assets since they form an integral part of the reliability program for the distribution system. They are not intended for resale and cannot be classified as inventory in accordance with CICA Handbook Section 3030.

- Amortization is provided on a straight line basis for capital assets available for use over their estimated service lives. In the changeover from CGAAP to MIFRS an evaluation was completed on all Grimsby Power Inc.'s assets to determine if the useful lives required restatement. Grimsby Power Inc. utilized the expert services and advice of KPMG to determine useful lives under MIFRS. More information on Grimsby Power Inc.'s transition to IFRS is detailed in Exhibit 4. The useful lives determined for all assets in conjunction with MIFRS is shown in Table 2.3 as follows:

Table 2.3 Useful Life of Assets

Component (MIFRS)	Component (CGAAP)	Useful Life (MIFRS)	Useful Life (CGAAP)
Land	Land	N/A	N/A
Buildings	Buildings – Robert Road	50	50
Buildings – Paving/Fencing	Buildings – Robert Road	40	40
Buildings – Other Fixtures	Buildings – Robert Road & Other	25	25
Overhead Poles		60	25
Overhead Line Switches and	Overhead Conductors &	60	25

Conductors	Devices		
Overhead Secondary Cables	Overhead Services	60	25
Underground Primary Cable & Switchgear	Underground Conductor & Devices	35	25
Underground Secondary Cables	Underground Services	40	25
Underground Ducts	Underground Conduit	70	25
Underground Concrete Encased Duct Banks	Underground Conduit	70	25
Overhead Transformers		35	25
Underground Transformers		30	25
Residential Meters (Stranded Meters)	Meters – Single & 3 Phase	25	25
Smart Meters			15
Industrial/Commercial Energy Meters	Interval Meters – 1 Phase, 3 Phase, & Meters YE Adj.	15	25
Wholesale Energy Meters	Meters	15	25
Other Meters – PT's & CT's	Meters	35	25
Office Furniture & Equipment		10	10
Computer Equipment Hardware		5	5
Computer Software		5	5

Vehicles	Transportation Equipment	15	15
Tools, Shop, Garage Equipment		10	10
Measurement & Testing Equipment		5	5
Wireless Communication	Communication Equipment	5	10

Amortization for 2012 has been recorded utilizing the half year rule. For years prior to this full amortization was recorded. For assets which are readily identified, the amortization occurs on a monthly basis.

- Disposals and Write Downs

The disposition of fixed assets is handled differently between Distribution Plant Assets and General Plant Assets.

The Distribution Plant Assets write downs are expensed as incurred or if they are subject to recovery in future rates they are deferred.

The General Plant Assets are removed from the books when the assets are retired. Gains or losses from the retirement or disposal of the asset are not being treated as an extraordinary item and are recorded in USoA accounts 4355 & 4360.

Grimsby Power Inc.'s Distribution System

Grimsby Power Inc. owns and operates the electricity distribution system in the Town of Grimsby serving more than 10,100 residential and business customers. Grimsby Power Inc. is supplied power from two transformer stations at 27.6kV, one transformer station (Beamsville TS) owned and operated by Hydro One Networks

Inc. and one transformer station owned by Niagara West Transformation Corporation (NWTC). Grimsby Power Inc. distributes electricity to the Town of Grimsby at the primary voltage of 27.6kV and also through two distribution substations which step down voltage to 8.32kV. These distribution substations are known as Kerman DS and Baker DS.

Grimsby Power Inc.'s licensed service area is 69 square kilometres consisting of 50 square kilometres of rural service area and 19 square kilometres of urban service area. Grimsby Power Inc.'s distribution system is made up of approximately 139.6 kilometres of overhead lines, 33.2 kilometres of underground lines, 3841 poles, 871 pole mount distribution transformers, 503 1 phase pad mount distribution transformers, 104 3 phase pad mount transformers and 10,186 meters of which 10,064 are Smart Meters installed on Residential and General Service <50 kW customers.

ASSET MANAGEMENT PLAN

Grimsby Power Inc. has developed a Distribution Asset Management Plan (DAMP) which outlines the capital and operating expenditures necessary to ensure that Grimsby Power Inc. continues to provide the highest standards for the safe, reliable supply of electricity at the lowest cost. A copy of the DAMP is attached to this Exhibit as Appendix 2.1.

The DAMP provides for:

- Replacement and voltage conversion of plant which has been fully depreciated and which is generally older than 50 years of age.
- Inspection and testing of existing plant
- Maintenance & inspection of distribution assets

Grimsby Power Inc.'s DAMP has been developed with due regard to the different Acts, Regulations, Codes and Guidelines and the continual updating of good utility practice to ensure the needs of the Town of Grimsby and Grimsby Power Inc.'s customers are met. The DAMP has been prepared for submission with Grimsby Power Inc.'s Cost of Service Rate Application and is a first generation document which centralizes a number of asset management processes and the knowledge of those administrating the asset management system. The DAMP includes well defined and executed asset processes as well as newly developed systems. These newly developed systems are either under development or in the implementation stages.

HARMONIZED SALES TAX ("HST")

Grimsby Power Inc. has adjusted its 2012 budget to account for calculated savings from the implementation of the HST. A study was undertaken to ascertain the impact to both capital and OM&A accounts as a result of the changes in tax. Grimsby Power Inc.'s calculation is as follows in Table 2.4 below:

In order to calculate the PST embedded in the costs, starting July 01, 2010 the amounts that would have the PST component were recorded in a separate "HST Saving Account". Based on the inventory amount issued in 2010, a calculation of the split percentage between capital and OM&A costs was completed. These percentages serve as a proxy on the inventory purchased. The expenses subject to PST were added to the inventory purchased for capital assets and expenses.

Table 2.4 HST Calculation

HST Calculation

Inventory Issued off:			2010	2011	Total
474,219.92	Capital Job Cost	88%	43,697.53	25,661.49	69,359.02
61,785.08	OM&A Job Cost	12%	5,693.26	3,343.38	9,036.64
536,005.00	Total Amount 2010 Job Cost	100%	**49,390.79**	**29,004.87**	**78,395.66**

	Inventory	Expenses	13%	8%	
OM&A	9,036.64	20,232.70	29,269.34	18,011.90	18,011.90
Capital	69,359.02		69,359.02	42,682.48	711.37
			98,628.36	**60,694.38**	**18,723.27**
50%	returnable to ratepayers		**9,361.64**		

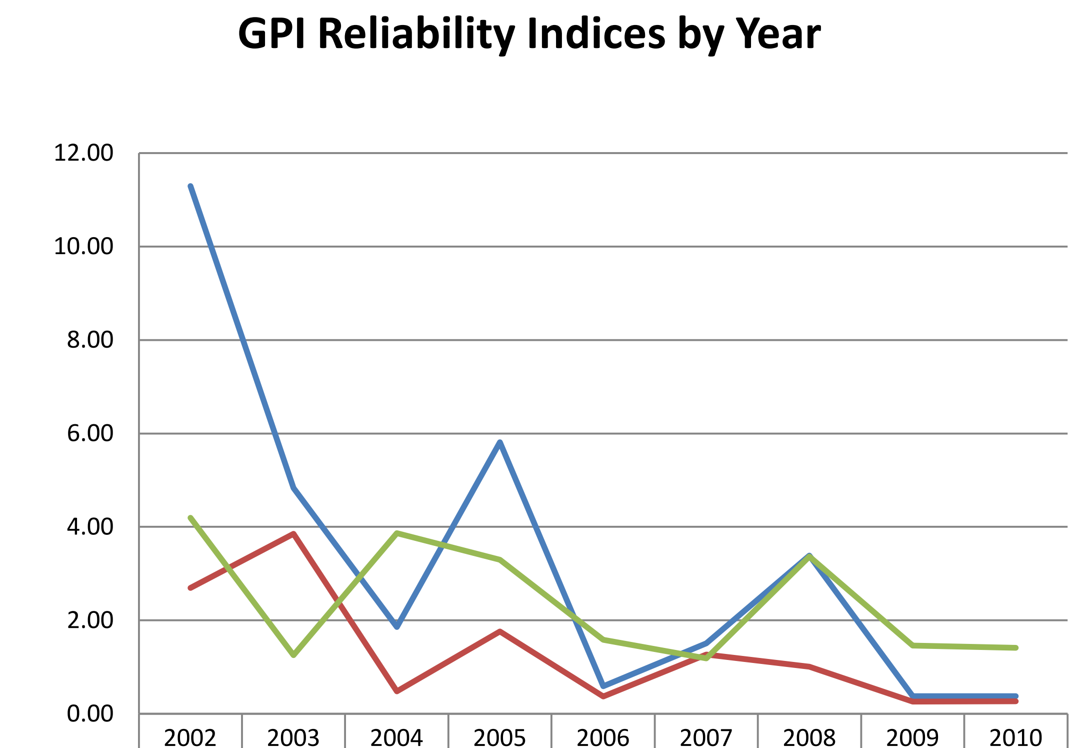
The savings in tax has been accounted for by subtracting the dollar values indicated in Table 2.4 above from GL #1830 ($ 42,682.48) and GL #5160 ($ 18,011.90).

SERVICE QUALITY AND RELIABILITY PERFORMANCE

Grimsby Power Inc. monitors and relies on its service quality and reliability indices (SQIs) as a means of measuring system performance. Grimsby Power Inc.'s commitment to stakeholders is to ensure the "highest standards of performance and business excellence for the safe, reliable provision of service". Reliability issues outside of the average or normal are brought to the attention of the Board of Directors in regular Board meetings within the CEO's Report to the Board.

Chart 2.2 below provides Grimsby Power Inc.'s reliability performance indices for each of the measures over the period 2002-2010. Year over year fluctuations may result from variations in weather such as extreme lightning, excessive snowfalls, ice storms, foreign interference such as animal contacts and motor vehicle accidents. Grimsby Power Inc.'s system performance indices are trending positively in a downward direction. In 2008 both duration indices increased due to a summer storm which affected a large number of customers at the same time. The downward trend is attributed to the addition of two feeders from the Niagara West Transformer Station in 2004 and the continued rebuilding of distribution equipment above the escarpment.

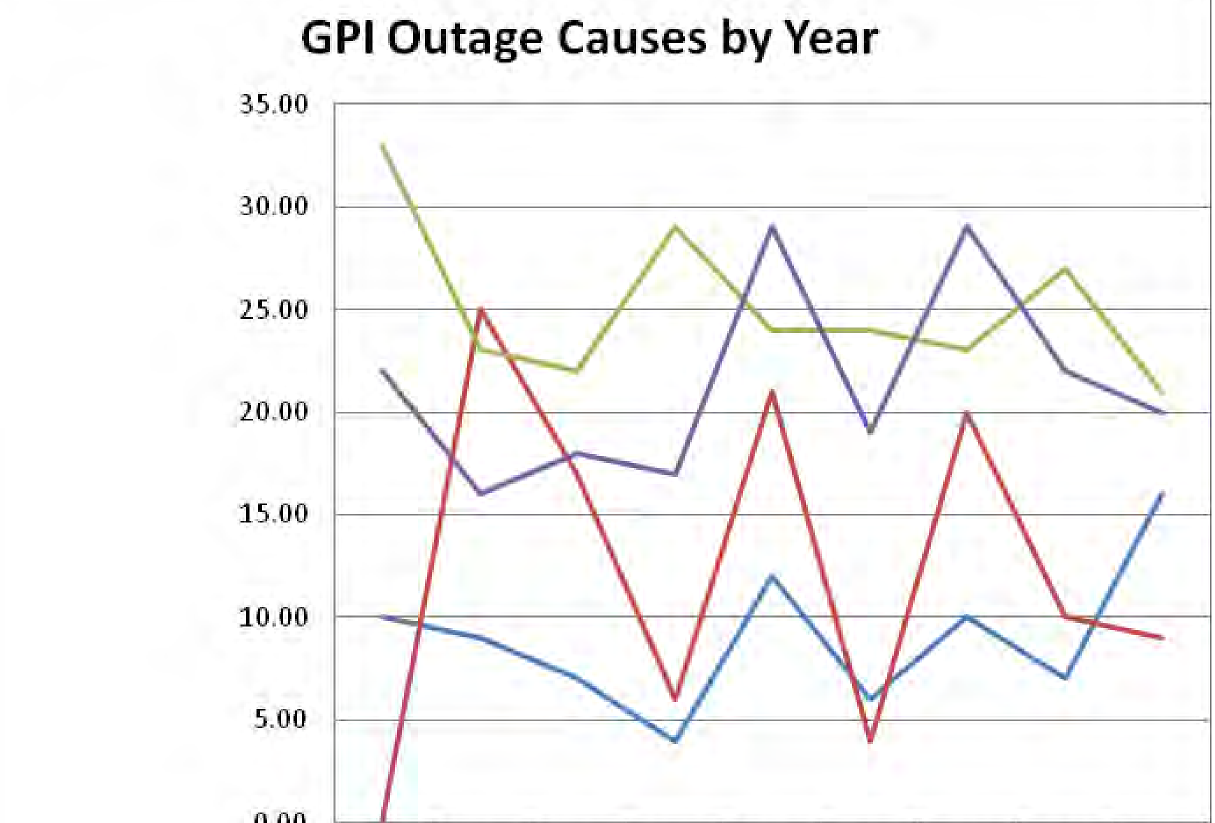
Chart 2.2 GPI Reliability Indices by Year



	2002	2003	2004	2005	2006	2007	2008	2009	2010
SAIDI	11.2903	4.8321	1.8603	5.8143	0.5896	1.5095	3.3876	0.3797	0.38
SAIFI	2.6926	3.854	0.4811	1.7624	0.3716	1.2715	1.0072	0.2594	0.27
CAIDI	4.1931	1.2538	3.8668	3.299	1.5868	1.1872	3.3633	1.4636	1.41

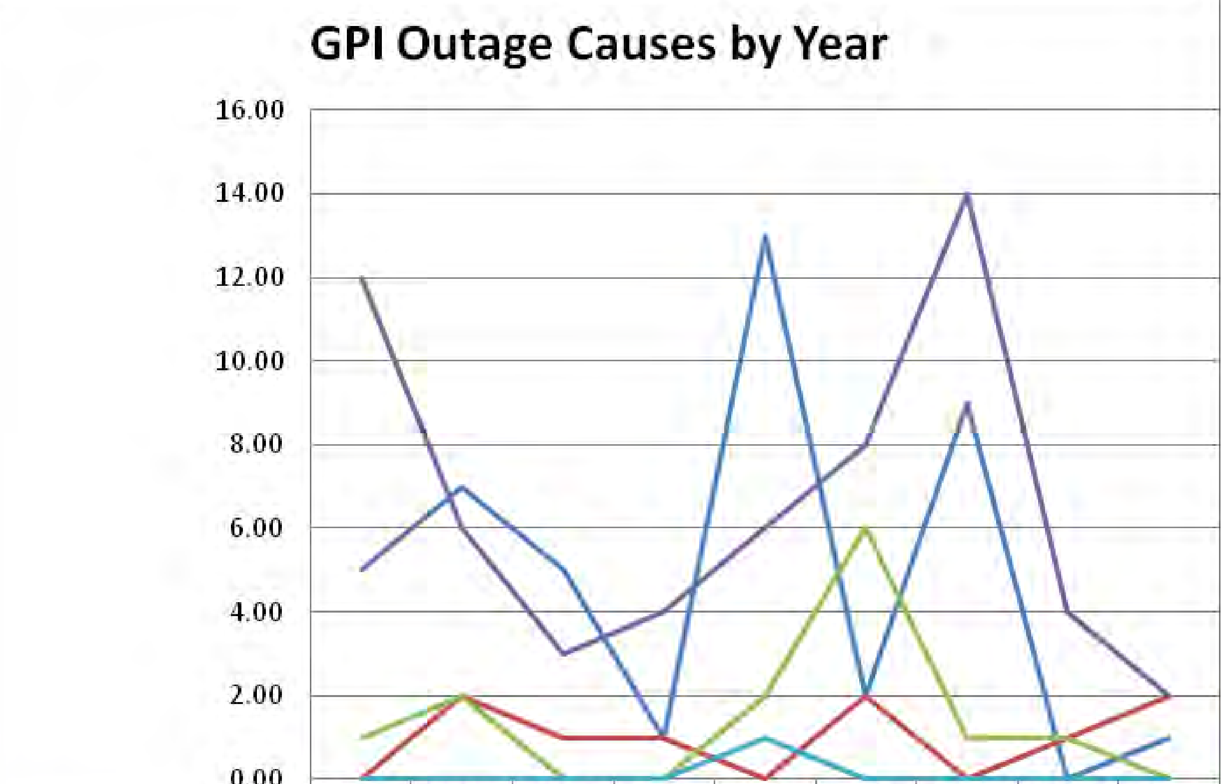
Grimsby Power Inc. also tracks the cause of outages (Service Interruptions by Code), from which Grimsby Power Inc. is able to determine whether corrective action is required to prevent or reduce similar occurrences. This information is provided in Chart 2.3 and 2.4 below. The causes have been split into two charts for clarity. The two most significant factors are defective equipment and foreign interference.

Chart 2.3 GPI Outage Causes by Year



	2002	2003	2004	2005	2006	2007	2008	2009	2010
Tree Contacts	10	9	7	4	12	6	10	7	16
Lightning	0	25	17	6	21	4	20	10	9
Defective Equipment	33	23	22	29	24	24	23	27	21
Foreign Interference	22	16	18	17	29	19	29	22	20

Chart 2.4 GPI Outage Causes by Year Part Two



	2002	2003	2004	2005	2006	2007	2008	2009	2010
Unknown	5	7	5	1	13	2	9	0	1
Scheduled Outage	0	2	1	1	0	2	0	1	2
Loss of Supply	1	2	0	0	2	6	1	1	0
Adverse Weather	12	6	3	4	6	8	14	4	2
Human Element	0	0	0	0	1	0	0	0	0

RATE BASE VARIANCE ANALYSIS

The following Table 2.5 sets out Grimsby Power Inc.'s year over year rate base variances for 2006 Board Approved, 2006 - 2010 Actual, 2011 Bridge Year and 2012 Test Year. Grimsby Power Inc. notes that the 2006 OEB Approved rate base was determined through the 2006 EDR process and is based on the 2004 year end rate base adjusted for Tier 1 Adjustments. Accordingly, the variance between 2006 Actual and 2006 OEB Approved spans a two-year period.

Table 2.5 Rate Base Variances

Description	2006 Actual Variance from 2006 OEB Approved	2007 Actual Variance from 2006 Actual	2008 Actual Variance from 2007 Actual	2009 Actual Variance from 2008 Actual	2010 Actual Variance from 2009 Actual	2011 Bridge Year Variance from 2010 Actual	2012 CGAAP Test Year Variance from 2011 Bridge Year	2012 IFRS Test Year Variance from 2011 Bridge Year
Gross Fixed Assets	2,454,086	892,828	935,768	1,062,086	188,655	2,920,412	1,317,649	1,306,840
Accumulated Depreciation	1,962,255	761,950	871,463	585,680	291,380	1,151,978	1,135,984	709,099
Net Book Value	491,832	130,878	64,305	476,406	(102,725)	1,768,434	181,665	597,741
Average Net Book Value	477,332	79,938	97,591	270,356	186,840	832,855	975,050	1,183,087
Working Capital	1,741,851	892,247	(301,217)	288,964	1,950,723	1,635,731	824,172	987,992
Working Capital Allowance	261,279	133,837	(45,182)	43,345	292,608	245,360	123,626	148,199
Rate Base	738,611	213,775	52,409	313,701	479,448	1,078,215	1,098,676	1,331,286

Gross Fixed Asset Variance Analysis

As shown in Chart 2.1, the Town of Grimsby has experienced modest growth since 2005 which has required Grimsby Power Inc. to invest in the expansion of its distribution system to service this growth. In addition to this growth Grimsby Power Inc.'s asset strategy to eliminate its aging distribution stations has required Grimsby Power Inc. to invest at an average level in excess of its annual accumulated depreciation.

For the purposes of this Application, Grimsby Power Inc. has provided information for the period 2004 and forward. Grimsby Power Inc.'s investment in capital has increased in each year from 2006 to 2010 as set out in Table 2.6 below – Percentage Change in Gross Fixed Assets. Grimsby Power would note that the percentage increase in gross fixed assets for the 2004 Actual over the 2006 OEB Approved is over a two year period as compared to the percent change in the 2007 Actual over the 2006 Actual gross fixed assets. Grimsby Power Inc.'s capital additions by USoA for the years 2006 to the 2012 Test Year, is provided in Table 2.7 and discussed in further detail in this Exhibit.

Table 2.6 Percentage Change in Gross Fixed Assets

Description	2006 Actual Variance from 2006 OEB Approved	2007 Actual Variance from 2006 Actual	2008 Actual Variance from 2007 Actual	2009 Actual Variance from 2008 Actual	2010 Actual Variance from 2009 Actual	2011 Bridge Year Variance from 2010 Actual	2012 CGAAP Test Year Variance from 2011 Bridge Year	2012 IFRS Test Year Variance from 2011 Bridge Year
Gross Fixed Assets	13.29%	4.27%	4.29%	4.67%	0.79%	12.17%	4.89%	4.63%
Accumulated Depreciation	23.85%	7.48%	7.96%	4.95%	2.35%	9.07%	8.20%	4.73%
Net Book Value	4.80%	1.22%	0.59%	4.36%	-0.90%	15.65%	1.39%	4.51%
Average Net Book Value	4.66%	0.75%	0.90%	2.48%	1.67%	7.34%	8.00%	8.99%
Working Capital	13.84%	6.23%	-1.98%	1.94%	12.83%	9.53%	4.39%	5.04%
Working Capital Allowance	13.84%	6.23%	-1.98%	1.94%	12.83%	9.53%	4.39%	5.04%
Rate Base	6.09%	1.66%	0.40%	2.39%	3.57%	7.74%	7.32%	8.27%

Table 2.7 Capital Additions 2006 actual to 2012 Test Year

USoA	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 CGAAP Test Year	2012 IFRS Test Year
1830	Poles, Towers and Fixtures	87,439	307,783	252,040	267,602	345,562	505,277	246,699	204,352
1835	Overhead Conductors and Devices	12,401	234,282	173,651	270,594	319,085	215,534	289,322	242,816
1840	Underground Conduit	30,476	257,246		22,598	292,541	15,000		
1845	Underground Conductors and Devic	176,600	246,900	112,392	144,476	275,188	121,408	154,611	148,446
1850	Line Transformers	356,872	437,436	289,202	278,085	543,894	333,391	242,292	184,446
1855	Services	86,946	320,307	110,419	138,613	298,045	54,140	50,225	43,671
1860	Meters	45,710	46,935	54,644	209,248	76,855	3,803	34,830	33,439
1908	Buildings and Fixtures			3,799	1,149	71,174	77,240	82,570	82,570
1915	Office Furniture and Equipment	22,134		7,870		7,053			
1920	Computer Equipment - Hardware	15,738	(3,138)	8,656	31,946	14,365	11,500	17,850	17,850
1925	Computer Software	129,534	21,649	75,681	142,796	33,120	222,500	24,950	24,950
1930	Transportation Equipment	26,409	22,173	10,009	21,795	926	30,000	299,000	299,000
1940	Tools, Shop and Garage Equipment		11,025	5,570	5,130	38,148		1,600	1,600
1945	Measurement and Testing Equipment		16,186		3,014	5,648	5,000		
1955	Communication Equipment							23,700	23,700
1995	Contributions and Grants	(106,169)	(931,914)	(162,610)	(87,808)	(867,342)	(150,000)	(150,000)	
	Total before Work in Process	**884,091**	**986,871**	**941,323**	**1,449,238**	**1,454,262**	**1,444,793**	**1,317,649**	**1,306,840**
	Work in Process		66,483	23,653	(90,136)	4,740	(4,740)		
	Total after Work in Process	**884,091**	**1,053,354**	**964,976**	**1,359,103**	**1,459,002**	**1,440,053**	**1,317,649**	**1,306,840**

Grimsby Power Inc. has two key drivers of its capital investment. The first driver is Grimsby Power Inc.'s own capital investment required to meet its commitment to provide a safe and reliable supply of electricity to its customers. Details are provided in Grimsby Power Inc.'s Distribution Asset Management Plan attached as Appendix 2.1 to this Exhibit but in summary includes the rebuilding and conversion of deteriorating 8.32kV distribution plant, pole replacement, silicone injection, and other capital works required as a result of inspection and testing of existing distribution plant. Other Asset investments include building/facilities, computer hardware, software, vehicles and communication equipment.

The second driver of Grimsby Power Inc.'s capital investment is its obligation to connect a customer in accordance with Section 28 of the *Electricity Act, 1998*, Section 7 of Grimsby Power Inc.'s Electricity Distribution License and the Distribution System Code. Residential subdivision developments make up the bulk of this driver. Grimsby Power Inc. contributes to the subdivision based on an economic evaluation in accordance with the DSC. All subdivision developers use the alternative bid provisions in the DSC to build the subdivision based on Grimsby Power's subdivision agreement which outlines specifications and Grimsby Power Inc. contributes based on actual connections and load over a 5 year horizon.

Capital Projects Exceeding Materiality Threshold

The following section sets out the year over year variances in Grimsby Power Inc's capital expenditures by the OEB's USoA classification. Also provided are the annual fixed asset continuity schedules, capital projects by USoA and explanations for the capital projects exceeding the materiality threshold of $50,000. This information has been presented for the years 2006 to 2010 Actuals, the 2011 Bridge Year, the 2012 Test Year (CGAAP), and the 2012 Test Year (MIFRS).

Table 2.8 below sets out the year over year gross asset variances by the OEB's USoA classification. Grimsby Power Inc. has prepared the year over year analysis in a consistent format for comparison purposes.

Table 2.8 Gross Asset Variances by Year

Description	2006 Actual Variance from 2006 OEB Approved	2007 Actual Variance from 2006 Actual	2008 Actual Variance from 2007 Actual	2009 Actual Variance from 2008 Actual	2010 Actual Variance from 2009 Actual	2011 Bridge Year Variance from 2010 Actual	2012 CGAAP Test Year Variance from 2011 Bridge Year	2012 IFRS Test Year Variance from 2011 Bridge Year
Gross Fixed Assets	2,454,086	892,828	935,768	1,062,086	188,655	2,920,412	1,317,649	1,306,840
Accumulated Depreciation	1,962,255	761,950	871,463	585,680	291,380	1,151,978	1,135,984	709,099
Net Book Value	491,832	130,878	64,305	476,406	(102,725)	1,768,434	181,665	597,741
Average Net Book Value	477,332	79,938	97,591	270,356	186,840	832,855	975,050	1,183,087
Working Capital	1,741,851	892,247	(301,217)	288,964	1,950,723	1,635,731	824,172	987,992
Working Capital Allowance	261,279	133,837	(45,182)	43,345	292,608	245,360	123,626	148,199
Rate Base	738,611	213,775	52,409	313,701	479,448	1,078,215	1,098,676	1,331,286

Grimsby Power Inc. has prepared and presented the year over year analysis for each year in a consistent format for comparison purposes. The Fixed Asset Continuity Schedules shown below are the Boards Appendix 2-B Tables for each year. The project Tables shown below are the Boards Appendix 2-A Tables for each year.

2006 Actual Capital Additions

The 2006 Fixed Asset Continuity Schedule, Table 2.9 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in Grimsby Power Inc.'s Revenue Requirement Model filed with this Application.

Table 2.9 2006 Fixed Asset Continuity Schedule

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] 2006

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land					$ -				$ -	$ -
47	1808	Buildings					$ -				$ -	$ -
13	1810	Leasehold Improvements					$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV					$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 143,555			$ 143,555	$ (143,555)			$ (143,555)	$ -
47	1825	Storage Battery Equipment					$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	4%	$ 6,211,841	$ 87,439		$ 6,299,280	$ (2,959,940)	$ (249,535)		$ (3,209,475)	$ 3,089,805
47	1835	Overhead Conductors & Devices	4%	$ 1,105,752	$ 12,401		$ 1,118,153	$ (128,075)	$ (44,726)		$ (172,801)	$ 945,352
47	1840	Underground Conduit	4%	$ 4,508,023	$ 30,476		$ 4,538,499	$ (1,921,850)	$ (173,141)		$ (2,094,992)	$ 2,443,507
47	1845	Underground Conductors & Devices	4%	$ 847,894	$ 176,600		$ 1,024,494	$ (104,641)	$ (40,980)		$ (145,621)	$ 878,873
47	1850	Line Transformers	4%	$ 5,513,820	$ 356,872		$ 5,870,692	$ (2,329,238)	$ (219,874)		$ (2,549,112)	$ 3,321,580
47	1855	Services (Overhead & Underground)	4%	$ 951,051	$ 86,946		$ 1,037,996	$ (91,594)	$ (41,540)		$ (133,134)	$ 904,863
47	1860	Meters	4%	$ 1,215,046	$ 45,710		$ 1,260,756	$ (538,776)	$ (42,323)		$ (581,098)	$ 679,657
47	1860	Meters (Smart Meters)					$ -				$ -	$ -
N/A	1905	Land		$ 111,556			$ 111,556				$ -	$ 111,556
CEC	1906	Land Rights					$ -				$ -	$ -
47	1908	Buildings & Fixtures	2%	$ 679,559			$ 679,559	$ (270,709)	$ (13,749)		$ (284,459)	$ 395,100
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10%	$ 120,271	$ 22,134	$ (9,532)	$ 132,873	$ (105,775)	$ (6,142)	$ 9,532	$ (102,385)	$ 30,488
8	1915	Office Furniture & Equipment (5 years)					$ -				$ -	$ -
45	1920	Computer Equipment - Hardware	33%	$ 282,395	$ 15,738		$ 298,133	$ (244,192)	$ (21,257)		$ (265,449)	$ 32,684
12	1925	Computer Software	20%	$ 239,207	$ 129,534		$ 368,742	$ (159,362)	$ (73,549)		$ (232,911)	$ 135,831
10	1930	Transportation Equipment	20%	$ 724,424	$ 26,409	$ (19,015)	$ 731,819	$ (605,104)	$ (32,033)	$ 19,015	$ (618,123)	$ 113,696
8	1935	Stores Equipment		$ 47,652			$ 47,652	$ (47,652)			$ (47,652)	$ -
8	1940	Tools, Shop & Garage Equipment	10%	$ 134,139			$ 134,139	$ (95,966)	$ (7,248)		$ (103,214)	$ 30,925
8	1945	Measurement & Testing Equipment	20%	$ 53,333			$ 53,333	$ (31,002)	$ (3,662)		$ (34,664)	$ 18,669
8	1950	Power Operated Equipment					$ -				$ -	$ -
8	1955	Communications Equipment		$ 9,002		$ (9,002)	$ -	$ (6,302)		$ 6,302	$ -	$ -
8	1955	Communication Equipment (Smart Meters)					$ -				$ -	$ -
8	1960	Miscellaneous Equipment					$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises					$ -				$ -	$ -
47	1980	System Supervisor Equipment					$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets					$ -				$ -	$ -
47	1995	Contributions & Grants	4%	$ (2,821,350)	$ (106,169)		$ (2,927,518)	$ 411,258	$ 117,367		$ 528,625	$ (2,398,893)
WIP	2055	Construciton Work in Progress					$ -				$ -	$ -
		Total		**$ 20,077,171**	**$ 884,091**	**$ (37,548)**	**$ 20,923,713**	**$ (9,372,477)**	**$ (852,392)**	**$ 34,849**	**$ (10,190,021)**	**$ 10,733,692**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	$ (32,033)
Stores Equipment	$ (10,910)
Net Depreciation	$ (809,449)

2006 Actual Capital Projects (Exceeding Threshold)

The following Table 2.10 provides Grimsby Power Inc.'s capital additions, exceeding the materiality threshold of $50,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold. In the category "Distribution Plant Under Threshold" are approximately 80 different projects which fall under one of the general categories described earlier in this Exhibit.

Table 2.10 2006 Actual Capital Projects

Appendix 2-A
Capital Projects Table

Year: 2006

USoA #	Description	CCA Class	Foran's Marine - 3 Phase Service	Christian Church - Woolverton	Underground Cable Injection - Woodlands	Subdivision Development - Assumed Plant	Accounting Software - APPX	General Plant Under Threshold	Distribution Plant Under Threshold	Contributions and Grants	Total
1830	Poles, Towers, & Fixtures	47							$ 87,439		$ 87,439
1835	Overhead Conductors & Devices	47							$ 12,401		$ 12,401
1840	Underground Conduit	47				$ 30,476					$ 30,476
1845	Underground Conductors & Devices	47	$ 7,752		$ 104,714	$ 11,892			$ 52,241		$ 176,600
1850	Line Transformers	47	$ 43,971	$ 54,899	$ 3,497	$ 4,875			$ 249,630		$ 356,872
1855	Services	47				$ 67,896			$ 19,050		$ 86,946
1860	Metering	47	$ 8,823	$ 9,053					$ 27,834		$ 45,710
1908	Buildings & Fixtures	47									$ -
1915	Office Furniture & Equipment	8						$ 22,135			$ 22,135
1920	Computer Equipment Hardware	45						$ 15,738			$ 15,738
1925	Computer Software	12					$ 103,538	$ 25,997			$ 129,534
1930	Transportation Equipment	10						$ 26,409			$ 26,409
1940	Tools, Shop, & Garage Equipment	8									$ -
1945	Measurement & Test Equipment	8									$ -
1955	Communication Equipment	8									$ -
1995	Contributions & Grants	47								$ (106,169)	$ (106,169)
Total			**$ 60,547**	**$ 63,952**	**$ 108,212**	**$ 115,139**	**$ 103,538**	**$ 90,279**	**$ 448,594**	**$ (106,169)**	**$ 884,091**

Project 2006: Customer – *Total Cost - $124,498*

Distribution work associated with connecting new customers to the distribution system or upgrading the distribution system to meet customer upgrades to their electrical services.

- Foran's Marine – 3 Phase Service $60,547
- Christian Church – Woolverton Road $63,952

Project 2006:* Silicone Injection of Underground Primary Cables - *Total Cost – $108,212

Injecting silicon into existing underground primary cables has proven to extend the life of the cables considerably. This is a continuation of an existing program which began in 2004. This year's program was in the Woodlands Subdivision.

Projects 2006: Subdivision Development – Assumed Plant - Total Cost – $115,139

The distribution infrastructure in residential subdivisions is installed by the developer under the alternative bid provisions in the Distribution System Code. The assets assumed by Grimsby Power Inc. are included in this category and reflect activity in any given year.

Projects 2006: Accounting Software - Total Cost – $103,538

In 2006, business application software was purchased and implemented. This product called APPX was implemented with modules including payroll, inventory control, accounts payable, and accounts receivable. The goal of this software was to integrate financial business processes and it replaced a "dos" based product called T&W which was not adequate.

2007 Actual Capital Additions

The 2007 Fixed Asset Continuity Schedule, Table 2.11 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in Grimsby Power Inc.'s Revenue Requirement Model filed with this Application.

Table 2.11 2007 Fixed Asset Continuity Schedule

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2007**

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1805	Land		$ -			$ -				$ -	$ -
47	1808	Buildings		$ -			$ -				$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 143,555			$ 143,555	$ (143,555)			$ (143,555)	$ -
47	1825	Storage Battery Equipment		$ -			$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	4%	$ 6,299,280	$ 307,783		$ 6,607,063	$ (3,209,475)	$ (261,206)		$ (3,470,681)	$ 3,136,382
47	1835	Overhead Conductors & Devices	4%	$ 1,118,153	$ 234,282		$ 1,352,435	$ (172,801)	$ (54,104)		$ (226,905)	$ 1,125,530
47	1840	Underground Conduit	4%	$ 4,538,499	$ 257,246		$ 4,795,744	$ (2,094,992)	$ (183,426)		$ (2,278,417)	$ 2,517,327
47	1845	Underground Conductors & Devices	4%	$ 1,024,494	$ 246,900		$ 1,271,395	$ (145,621)	$ (50,856)		$ (196,478)	$ 1,074,917
47	1850	Line Transformers	4%	$ 5,870,692	$ 437,436		$ 6,308,128	$ (2,549,112)	$ (238,448)		$ (2,787,561)	$ 3,520,567
47	1855	Services (Overhead & Underground)	4%	$ 1,037,996	$ 320,307		$ 1,358,304	$ (133,134)	$ (54,314)		$ (187,448)	$ 1,170,856
47	1860	Meters	4%	$ 1,260,756	$ 46,935		$ 1,307,691	$ (581,098)	$ (44,104)		$ (625,203)	$ 682,488
47	1860	Meters (Smart Meters)		$ -			$ -				$ -	$ -
N/A	1905	Land		$ 111,556			$ 111,556				$ -	$ 111,556
CEC	1906	Land Rights		$ -			$ -				$ -	$ -
47	1908	Buildings & Fixtures	2%	$ 679,559			$ 679,559	$ (284,459)	$ (13,749)		$ (298,208)	$ 381,351
13	1910	Leasehold Improvements		$ -			$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10%	$ 132,873		$ (2,770)	$ 130,103	$ (102,385)	$ (4,848)	$ 2,770	$ (104,463)	$ 25,640
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -				$ -	$ -
45	1920	Computer Equipment - Hardware	33%	$ 298,133	$ (3,138)	$ (28,718)	$ 266,277	$ (265,449)	$ (5,255)	$ 28,718	$ (241,986)	$ 24,291
12	1925	Computer Software	20%	$ 368,742	$ 21,649	$ (2,973)	$ 387,418	$ (232,911)	$ (51,899)	$ 2,973	$ (281,837)	$ 105,582
10	1930	Transportation Equipment	20%	$ 731,819	$ 22,173	$ (18,591)	$ 735,401	$ (618,123)	$ (36,467)	$ 18,591	$ (635,999)	$ 99,402
8	1935	Stores Equipment		$ 47,652		$ (566)	$ 47,086	$ (47,652)		$ 566	$ (47,086)	$ -
8	1940	Tools, Shop & Garage Equipment	10%	$ 134,139	$ 11,025	$ (32,692)	$ 112,473	$ (103,214)	$ (8,072)	$ 32,692	$ (78,594)	$ 33,879
8	1945	Measurement & Testing Equipment	20%	$ 53,333	$ 16,186	$ (7,734)	$ 61,786	$ (34,664)	$ (3,883)	$ 7,734	$ (30,814)	$ 30,972
8	1950	Power Operated Equipment		$ -			$ -				$ -	$ -
8	1955	Communications Equipment		$ -			$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -				$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -				$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -				$ -	$ -
47	1995	Contributions & Grants	4%	$ (2,927,518)	$ (931,914)		$ (3,859,433)	$ 528,625	$ 154,639		$ 683,264	$ (3,176,168)
WIP	2055	Construciton Work in Progress		$ -	$ 66,483		$ 66,483				$ -	$ 66,483
		Total		**$ 20,923,713**	**$ 1,053,354**	**$ (94,043)**	**$ 21,883,023**	**$ (10,190,021)**	**$ (855,993)**	**$ 94,043**	**$ (10,951,970)**	**$ 10,931,053**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	$ (36,467)
Stores Equipment	$ (11,955)
Net Depreciation	$ (807,571)

2007 Actual Capital Projects (Exceeding Threshold)

The following Table 2.12 provides Grimsby Power Inc.'s capital additions, exceeding the materiality threshold of $50,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold. In the category "Distribution Plant Under Threshold" are approximately 65 different projects which fall under one of the general categories described earlier in this Exhibit.

Table 2.12 2007 Actual Capital Projects

Appendix 2-A
Capital Projects Table

Year: 2007

USoA #	Description	CCA Class	Mud Street - Mountain to Woolverton	Underground Tx replacement - Woodlands	Service Upgrade - 496 Inglehart	Mud Street Conversion - Woolverton to SC Border	Subdivision Development - Assumed Plant	General Plant Under Threshold	Distribution Plant Under Threshold	Contributions and Grants	Total
1830	Poles, Towers, & Fixtures	47	$ 113,074			$ 125,336			$ 69,372		$ 307,783
1835	Overhead Conductors & Devices	47	$ 207,143			$ 17,829			$ 9,309		$ 234,282
1840	Underground Conduit	47	$ 37,075				$ 216,323		$ 3,848		$ 257,246
1845	Underground Conductors & Devices	47	$ 77,448	$ 3,471	$ 7,807		$ 137,221		$ 20,954		$ 246,900
1850	Line Transformers	47	$ 61,921	$ 82,981	$ 39,695		$ 167,732		$ 85,108		$ 437,436
1855	Services	47	$ 20,293			$ 7,220	$ 246,671		$ 46,124		$ 320,307
1860	Metering	47			$ 3,261				$ 43,674		$ 46,935
1908	Buildings & Fixtures	47									$ -
1915	Office Furniture & Equipment	8									$ -
1920	Computer Equipment Hardware	45						-$ 3,138			-$ 3,138
1925	Computer Software	12						$ 21,649			$ 21,649
1930	Transportation Equipment	10						$ 22,173			$ 22,173
1940	Tools, Shop, & Garage Equipment	8						$ 11,025			$ 11,025
1945	Measurement & Test Equipment	8						$ 16,186			$ 16,186
1955	Communication Equipment	8									$ -
1995	Contributions & Grants	47								-$ 931,914	-$ 931,914
2055	Construction Work in Progress		$ 66,483								$ 66,483
Total			**$ 583,437**	**$ 86,452**	**$ 50,763**	**$ 150,385**	**$ 767,945**	**$ 67,896**	**$ 278,389**	**-$ 931,914**	**$ 1,053,354**

Project 2007: Conversion to 27.6kV: Total cost $667,449

Two large projects were constructed in 2007 in support of Grimsby Power Inc.'s conversion program:

- Mud Street – Mountain Rd to Woolverton Rd $517,064
- Mud Street – Woolverton Rd to West Boundary $150,385

Project 2007: Customer Driven – Total Cost $50,763

Distribution work associated with connecting new customers to the distribution system:

- Service Upgrade – 496 Inglehart $50,763

Project 2007: Pad-Mount Replacement Program - Total Cost $86,452

The annual inspection of underground distribution transformers has uncovered what appears to be an increasing trend in defective pad mount transformers. These transformers sit on a concrete pad and this concrete to metal interface is causing severe corrosion of the transformer cases and tanks. These transformers cannot be repaired in the field and as such need to be replaced.

Projects 2007: Subdivision Development – Assumed Plant - Total Cost – $767,945

The distribution infrastructure in residential subdivisions is installed by the developer under the alternative bid provisions in the Distribution System Code. The assets assumed by Grimsby Power Inc. are included in this category and reflects activity in any given year.

2008 Actual Capital Additions

The 2008 Fixed Asset Continuity Schedule, Table 2.13 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in Grimsby Power Inc.'s Revenue Requirement Model filed with this Application.

Table 2.13 2008 Fixed Asset Continuity Schedule

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2008**

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land		$ -			$ -				$ -	$ -
47	1808	Buildings		$ -			$ -				$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 143,555			$ 143,555	$ (143,555)			$ (143,555)	$ -
47	1825	Storage Battery Equipment		$ -			$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 6,607,063	$ 252,040		$ 6,859,102	$ (3,470,681)	$ (269,006)		$ (3,739,686)	$ 3,119,416
47	1835	Overhead Conductors & Devices	4.00%	$ 1,352,435	$ 173,651		$ 1,526,087	$ (226,905)	$ (61,044)		$ (287,950)	$ 1,238,137
47	1840	Underground Conduit	4.00%	$ 4,795,744			$ 4,795,744	$ (2,278,417)	$ (183,430)		$ (2,461,847)	$ 2,333,897
47	1845	Underground Conductors & Devices	4.00%	$ 1,271,395	$ 112,392		$ 1,383,787	$ (196,478)	$ (55,344)		$ (251,822)	$ 1,131,965
47	1850	Line Transformers	4.00%	$ 6,308,128	$ 289,202		$ 6,597,330	$ (2,787,561)	$ (247,136)		$ (3,034,697)	$ 3,562,633
47	1855	Services (Overhead & Underground)	4.00%	$ 1,358,304	$ 110,419		$ 1,468,723	$ (187,448)	$ (58,743)		$ (246,191)	$ 1,222,532
47	1860	Meters	4.00%	$ 1,307,691	$ 54,644		$ 1,362,335	$ (625,203)	$ (46,168)		$ (671,370)	$ 690,965
47	1860	Meters (Smart Meters)		$ -			$ -				$ -	$ -
N/A	1905	Land		$ 111,556			$ 111,556				$ -	$ 111,556
CEC	1906	Land Rights		$ -			$ -				$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 679,559	$ 3,799		$ 683,357	$ (298,208)	$ (13,813)		$ (312,020)	$ 371,337
13	1910	Leasehold Improvements		$ -			$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 130,103	$ 7,870		$ 137,973	$ (104,463)	$ (4,580)		$ (109,043)	$ 28,930
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -				$ -	$ -
45	1920	Computer Equipment - Hardware	33.33%	$ 266,277	$ 8,656	$ (5,556)	$ 269,378	$ (241,986)	$ (10,963)	$ 3,848	$ (249,101)	$ 20,277
12	1925	Computer Software	20.00%	$ 387,418	$ 75,681		$ 463,099	$ (281,837)	$ (39,945)		$ (321,781)	$ 141,318
10	1930	Transportation Equipment	20.00%	$ 735,401	$ 10,009		$ 745,411	$ (635,999)	$ (33,306)		$ (669,306)	$ 76,105
8	1935	Stores Equipment		$ 47,086			$ 47,086	$ (47,086)			$ (47,086)	$ -
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 112,473	$ 5,570		$ 118,043	$ (78,594)	$ (7,138)		$ (85,732)	$ 32,310
8	1945	Measurement & Testing Equipment	20.00%	$ 61,786			$ 61,786	$ (30,814)	$ (5,860)		$ (36,674)	$ 25,112
8	1950	Power Operated Equipment		$ -			$ -				$ -	$ -
8	1955	Communications Equipment		$ -			$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -				$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -				$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -				$ -	$ -
47	1995	Contributions & Grants	4.00%	$ (3,859,433)	$(162,610)		$ (4,022,043)	$ 683,264	$ 161,164		$ 844,428	$ (3,177,614)
WIP	2055	Construciton Work in Progress		$ 66,483	$ 23,653		$ 90,136				$ -	$ 90,136
				$ -								
		Total		**$ 21,883,023**	**$ 964,976**	**$ (5,556)**	**$ 22,842,444**	**$ (10,951,970)**	**$ (875,311)**	**$ 3,848**	**$ (11,823,433)**	**$ 11,019,010**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	$ (33,306)
Stores Equipment	$ (957)
Net Depreciation	$(842,962)

2008 Actual Capital Projects (Exceeding Threshold)

The following Table 2.14 provides Grimsby Power Inc.'s capital additions, exceeding the materiality threshold of $50,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold. In the category "Distribution Plant under Threshold" are approximately 65 different projects which fall under one of the general categories described earlier in this Exhibit

Table 2.14 2008 Actual Capital Projects

Appendix 2-A
Capital Projects Table

Year: 2008

USoA #	Description	CCA Class	New Service - RONA	Mud Street Conv. - Woolverton to SC Border	South Service Road Extension 50% recoverable	Fairbrother from Sobie Load Transfer	Cable Injection - Driftwood	Kemp Road West Rebuild	Subdivision Development - Assumed Plant	Customer Information System Software - SAP	General Plant Under Threshold	Distribution Plant Under Threshold	Contributions and Grants	Total
1830	Poles, Towers, & Fixtures	47		$ 33,545	$ 31,685	$ 26,012		$ 66,638				$ 94,160		$ 252,040
1835	Overhead Conductors & Devices	47		$ 101,376	$ 15,309	$ 22,619		-$ 2,946				$ 37,294		$ 173,651
1840	Underground Conduit	47												$ -
1845	Underground Conductors & Devices	47	$ 5,748	$ 794			$ 81,633					$ 24,216		$ 112,392
1850	Line Transformers	47	$ 62,105	-$ 2,539	$ 15,610	$ 5,755	$ 2	$ 50,581				$ 157,688		$ 289,202
1855	Services	47		$ 473	$ 469	$ 1,775		$ 3,725	$ 82,200			$ 21,777		$ 110,419
1860	Metering	47	$ 4,974									$ 49,671		$ 54,644
1908	Buildings & Fixtures	47									$ 3,799			$ 3,799
1915	Office Furniture & Equipment	8									$ 7,870			$ 7,870
1920	Computer Equipment Hardware	45									$ 8,656			$ 8,656
1925	Computer Software	12								$ 70,200	$ 5,481			$ 75,681
1930	Transportation Equipment	10									$ 10,009			$ 10,009
1940	Tools, Shop, & Garage Equipment	8									$ 5,570			$ 5,570
1945	Measurement & Test Equipment	8												$ -
1955	Communication Equipment	8												$ -
1995	Contributions & Grants	47											-$ 162,610	-$ 162,610
2055	Construction Work in Progress							$ 90,136				-$ 66,483		$ 23,653
Total			**$ 72,827**	**$ 133,649**	**$ 63,073**	**$ 56,161**	**$ 81,635**	**$ 208,133**	**$ 82,200**	**$ 70,200**	**$ 41,385**	**$ 318,323**	**-$ 162,610**	**$ 964,976**

Project 2008: Conversion to 27.6kV: Total cost $251,647

GPI's remaining distribution stations (Kerman and Baker) have been in place for many years and are approaching end of life. GPI's distribution planning strategy has been to eliminate these stations by upgrading the 8kV distribution system to 27kV. Continuing with past efforts the following project was completed (or partially completed) in 2008:

- Kemp Rd West $177,625
- Mud Street – Woolverton Road to West Boundary $133,649

Project 2008: Customer Driven – Total Cost $72,827

Distribution work associated with connecting new customers to the distribution system:

- New Service – 359 South Service Road $72,827

Project 2008:* Silicone Injection of Underground Primary Cables - *Total Cost – $81,635

Injecting silicon into existing underground primary cables has proven to extend the life of the cables considerably. This is a continuation of an existing program which began in 2004. This year's program was in the Driftwood Subdivision.

Project 2008: Regulatory Requirements (Load Transfers) - Total Cost – $56,161

Infrastructure was installed to supply customers who were geographically in Grimsby Power Inc.'s service territory but fed from Niagara Peninsula Energy Inc. (Formerly Penn West). The particular location was on Fairbrother Road in the vicinity of Sobie Road.

Projects 2008: Computer Software - Total Cost – $70,200

In 2008 Grimsby Power Inc. entered into a service agreement with Canadian Niagara Power a FortisOntario company to provide software as a service (SAAS) Customer Information System (CIS) to replace the existing CIS system which was no longer supported by the Vendor – Advanced. The CIS platform utilizes SAP software which required Grimsby Power Inc. to purchase SAP licenses.

- SAP Software - $70,200

Projects 2008: Subdivision Development – Assumed Plant - Total Cost – $82,200

The distribution infrastructure in residential subdivisions is installed by the developer under the alternative bid provisions in the Distribution System Code. The assets assumed by Grimsby Power Inc. are included in this category and reflects activity in any given year.

2009 Actual Capital Additions

The 2009 Fixed Asset Continuity Schedule, Table 2.15 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in Grimsby Power Inc.'s Revenue Requirement Model filed with this Application.

Table 2.15 2009 Fixed Asset Continuity Schedule

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2009**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land		$ -			$ -				$ -	$ -
47	1808	Buildings		$ -			$ -				$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 143,555			$ 143,555	$ (143,555)			$ (143,555)	$ -
47	1825	Storage Battery Equipment		$ -			$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 6,859,102	$ 267,602		$ 7,126,704	$ (3,739,686)	$ (295,397)		$ (4,035,083)	$ 3,091,621
47	1835	Overhead Conductors & Devices	4.00%	$ 1,526,087	$ 270,594		$ 1,796,681	$ (287,950)	$ (71,861)		$ (359,810)	$ 1,436,870
47	1840	Underground Conduit	4.00%	$ 4,795,744	$ 22,598		$ 4,818,342	$ (2,461,847)	$ (165,590)		$ (2,627,438)	$ 2,190,904
47	1845	Underground Conductors & Devices	4.00%	$ 1,383,787	$ 144,476		$ 1,528,262	$ (251,822)	$ (55,591)		$ (307,413)	$ 1,220,850
47	1850	Line Transformers	4.00%	$ 6,597,330	$ 278,085		$ 6,875,415	$ (3,034,697)	$ (259,090)		$ (3,293,787)	$ 3,581,628
47	1855	Services (Overhead & Underground)	4.00%	$ 1,468,723	$ 138,613		$ 1,607,336	$ (246,191)	$ (74,743)		$ (320,934)	$ 1,286,402
47	1860	Meters	4.00%	$ 1,362,335	$ 209,248		$ 1,571,583	$ (671,370)	$ (55,114)		$ (726,484)	$ 845,099
47	1860	Meters (Smart Meters)		$ -			$ -				$ -	$ -
N/A	1905	Land		$ 111,556			$ 111,556				$ -	$ 111,556
CEC	1906	Land Rights		$ -			$ -				$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 683,357	$ 1,149		$ 684,507	$ (312,020)	$ (16,957)		$ (328,977)	$ 355,529
13	1910	Leasehold Improvements		$ -			$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 137,973		$ (6,851)	$ 131,122	$ (109,043)	$ (5,116)	$ 6,851	$ (107,308)	$ 23,814
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -				$ -	$ -
45	1920	Computer Equipment - Hardware	33.33%	$ 269,378	$ 31,946	$(181,326)	$ 119,997	$ (249,101)	$ (17,115)	$ 180,543	$ (85,672)	$ 34,325
12	1925	Computer Software	20.00%	$ 463,099	$ 142,796	$(171,794)	$ 434,101	$ (321,782)	$ (46,854)	$ 171,794	$ (196,841)	$ 237,261
10	1930	Transportation Equipment	20.00%	$ 745,411	$ 21,795	$ (22,539)	$ 744,667	$ (669,306)	$ (48,050)	$ 18,032	$ (699,324)	$ 45,343
8	1935	Stores Equipment		$ 47,086			$ 47,086	$ (47,086)			$ (47,086)	$ 0
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 118,043	$ 5,130	$ (4,643)	$ 118,530	$ (85,732)	$ (8,544)	$ 4,643	$ (89,634)	$ 28,896
8	1945	Measurement & Testing Equipment	20.00%	$ 61,786	$ 3,014		$ 64,800	$ (36,674)	$ (9,464)		$ (46,138)	$ 18,662
8	1950	Power Operated Equipment		$ -			$ -				$ -	$ -
8	1955	Communications Equipment		$ -			$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)		$ -			$ -				$ -	$ -
8	1960	Miscellaneous Equipment		$ -			$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -				$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -				$ -	$ -
47	1995	Contributions & Grants	4.00%	$ (4,022,043)	$ (87,808)		$ (4,109,851)	$ 844,428	$ 161,945		$ 1,006,373	$ (3,103,478)
WIP	2055	Construciton Work in Progress		$ 90,136	$ (90,136)		$ -				$ -	$ -
				$ -								
		Total		**$22,842,444**	**$1,359,103**	**$(387,152)**	**$23,814,394**	**$ (11,823,433)**	**$ (967,542)**	**$ 381,862**	**$(12,409,113)**	**$ 11,405,281**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	
Stores Equipment	
Net Depreciation	$(967,542)

2009 Actual Capital Projects (Exceeding Threshold)

The following Table 2.16 provides Grimsby Power Inc.'s capital additions, exceeding the materiality threshold of $50,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold. In the category "Distribution Plant under Threshold" are approximately 58 different projects which fall under one of the general categories described in earlier in this Exhibit.

Table 2.16 2009 Actual Capital Projects

Appendix 2-A
Capital Projects Table

Year: 2009

USoA #	Description	CCA Class	18 M3 Wholesale Meter Upgrade	Kemp Road West rebuild	Hysert Road rebuild	Cable Injection - Central	New Service - Clarke Street - Police Station	Ridge Rd W Rebuild Part 2	Ridge Rd W Rebuild Part 3	Ridge Rd W Rebuild Part 1	125 Livingston - refurbish	Subdivision Development - Assumed Plant	Graphical Information System Software Implementation	Customer Information System Software - SAP	General Plant Under Threshold	Distribution Plant Under Threshold	Contributions and Grants	Total
1830	Poles, Towers, & Fixtures	47		$ 33,480	$ 45,353		$ 3,583	$ 21,976	$ 45,358	$ 35,527						$ 82,324		$ 267,602
1835	Overhead Conductors & Devices	47		$ 38,821	$ 54,993		$ 1,598	$ 27,249	$ 39,086	$ 34,904	$ 1,468					$ 72,474		$ 270,594
1840	Underground Conduit	47									$ 20,738					$ 1,860		$ 22,598
1845	Underground Conductors & Devices	47				$ 82,961	$ 5,295				$ 22,428					$ 33,792		$ 144,476
1850	Line Transformers	47		$ 23,425	$ 38,893	$ 506	$ 19,892	$ 22,907	$ 36,769	$ 14,284	$ 24,599					$ 96,810		$ 278,085
1855	Services	47		$ 4,848	$ 13,089			$ 2,128	$ 2,547	$ 4,419	$ 11,029	$ 79,800				$ 20,755		$ 138,613
1860	Metering	47	$ 67,190		$ 17,064		$ 38,197									$ 86,796		$ 209,248
1908	Buildings & Fixtures	47													$ 1,149			$ 1,149
1915	Office Furniture & Equipment	8																$ -
1920	Computer Equipment Hardware	45													$ 31,946			$ 31,946
1925	Computer Software	12											$ 49,160	$ 60,383	$ 33,253			$ 142,796
1930	Transportation Equipment	10													$ 21,795			$ 21,795
1940	Tools, Shop, & Garage Equipment	8													$ 5,130			$ 5,130
1945	Measurement & Test Equipment	8													$ 3,014			$ 3,014
1955	Communication Equipment	8																$ -
1995	Contributions & Grants	47															-$ 87,808	-$ 87,808
2055	Construction Work in Progress			-$ 90,136														-$ 90,136
Total			**$ 67,190**	**$ 10,438**	**$ 169,393**	**$ 83,467**	**$ 68,566**	**$ 74,259**	**$ 123,760**	**$ 89,135**	**$ 80,261**	**$ 79,800**	**$ 49,160**	**$ 60,383**	**$ 96,288**	**$ 394,811**	**-$ 87,808**	**$ 1,359,103**

Project 2009: Conversion to 27.6kV: Total Cost $557,120

GPI's remaining distribution stations (Kerman and Baker) have been in place for many years and are approaching end of life. GPI's distribution planning strategy has been to eliminate these stations by upgrading the 8kV distribution system to 27kV. Continuing with past efforts the following projects were completed (or partially completed) in 2009:

• Hysert Rd	$169,393
• Kemp Rd West	$100,573
• Ridge Rd West – Part 1	$89,135
• Ridge Rd West – Part 2	$74,259
• Ridge Rd West – Part 3	$123,760

Project 2009: Customer Driven – Total Cost $68,566

Distribution work associated with connecting new customers to the distribution system:

• Clarke Street – Police Station	$68,566

Project 2009: Pad-Mount Replacement Program - Total Cost $80,261

The annual inspection of underground distribution transformers has uncovered what appears to be an increasing trend in defective pad mount transformers. These transformers sit on a concrete pad and this concrete to metal interface is causing severe corrosion of the transformer cases and tanks. These transformers cannot be repaired in the field and as such need to be replaced. This particular project was at 125 Livingston St.

Project 2009: Silicone Injection of Underground Primary Cables - _Total Cost – $83,467_

Injecting silicon into existing underground primary cables has proven to extend the life of the cables considerably. This is a continuation of an existing program which began in 2004. This year's program was in the Central Subdivision

Projects 2009: Smart Meter Communications Infrastructure - Total Cost – $181,194

The Smart Meter project began to materialize in 2009 with the installation of the infrastructure to support the meter data communications. The investments in smart meter communications infrastructure is not part of the project capital list – the communication devices were recorded in the 1555 capital variance account and include costs in relation to smart meter minimum functionality.

Projects 2009: Metering - Total Cost – $67,190

The wholesale metering on the 18M3 feeder out of Beamsville TS was out of compliance. The current and potential transformers were replaced as well as the meter.

Projects 2009: Subdivision Development – Assumed Plant - Total Cost – $79,800

The distribution infrastructure in residential subdivisions is installed by the developer under the alternative bid provisions in the Distribution System Code. The assets assumed by Grimsby Power Inc. are included in this category and reflects activity in any given year.

Projects 2009: Computer Software - Total Cost – $109,543

Grimsby Power Inc.'s GIS platform had been in place since the early days of digital mapping. A market study determined that the ESRI GIS platform was the best fit for Grimsby Power Inc.'s needs.

In 2008 Advanced (CIS service provider) informed all LDC’s in Ontario that it would no longer support its product beyond January 2009. To this end Grimsby Power Inc. partnered with Canadian Niagara Power Inc. (CNPI) a FortisOntario company to provide a Customer Information System for its use. The CIS is provided by CNPI on a software as a service (SAAS) model under a service level agreement. Costs in 2009 relate to the implementation of SAP.

- ESRI Cost - $49,160
- SAP Implementation Cost - $60,383

2010 Actual Capital Additions

The 2010 Fixed Asset Continuity Schedule, Table 2.17 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in Grimsby Power Inc.’s Revenue Requirement Model filed with this Application.

Table 2.17 2010 Fixed Asset Continuity Schedule

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2010**

			Cost				Accumulated Depreciation				
OEB	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
1805	Land		$ -			$ -				$ -	$ -
1808	Buildings		$ -			$ -				$ -	$ -
1810	Leasehold Improvements		$ -			$ -				$ -	$ -
1815	Transformer Station Equipment >50 kV		$ -			$ -				$ -	$ -
1820	Distribution Station Equipment <50 kV		$ 143,555			$ 143,555	$ (143,555)			$ (143,555)	$ -
1825	Storage Battery Equipment		$ -			$ -				$ -	$ -
1830	Poles, Towers & Fixtures	4.00%	$ 7,126,704	$ 345,562		$ 7,472,266	$ (4,035,083)	$ (283,241)		$ (4,318,324)	$ 3,153,942
1835	Overhead Conductors & Devices	4.00%	$ 1,796,681	$ 319,085		$ 2,115,766	$ (359,810)	$ (84,640)		$ (444,451)	$ 1,671,315
1840	Underground Conduit	4.00%	$ 4,818,342	$ 292,541		$ 5,110,882	$ (2,627,438)	$ (195,455)		$ (2,822,893)	$ 2,287,990
1845	Underground Conductors & Devices	4.00%	$ 1,528,262	$ 275,188		$ 1,803,450	$ (307,413)	$ (72,127)		$ (379,539)	$ 1,423,911
1850	Line Transformers	4.00%	$ 6,875,415	$ 543,894		$ 7,419,309	$ (3,293,787)	$ (290,483)		$ (3,584,270)	$ 3,835,039
1855	Services (Overhead & Underground)	4.00%	$ 1,607,336	$ 298,045		$ 1,905,381	$ (320,934)	$ (76,211)		$ (397,145)	$ 1,508,236
1860	Meters	4.00%	$ 1,571,583	$ 76,855	$(1,259,487)	$ 388,952	$ (726,484)	$ (20,231)	$ 678,430	$ (68,285)	$ 320,667
1860	Meters (Smart Meters)		$ -			$ -				$ -	$ -
1905	Land		$ 111,556			$ 111,556				$ -	$ 111,556
1906	Land Rights		$ -			$ -				$ -	$ -
1908	Buildings & Fixtures	2.00%	$ 684,507	$ 71,174		$ 755,681	$ (328,977)	$ (14,817)		$ (343,794)	$ 411,887
1910	Leasehold Improvements		$ -			$ -				$ -	$ -
1915	Office Furniture & Equipment (10 years)	10.00%	$ 131,122	$ 7,053	$ (936)	$ 137,239	$ (107,308)	$ (5,028)	$ 172	$ (112,165)	$ 25,074
1915	Office Furniture & Equipment (5 years)		$ -			$ -				$ -	$ -
1920	Computer Equipment - Hardware	33.33%	$ 119,997	$ 14,365	$ (5,184)	$ 129,178	$ (85,672)	$ (18,161)	$ 5,184	$ (98,650)	$ 30,528
1925	Computer Software	20.00%	$ 434,101	$ 33,120		$ 467,221	$ (196,840)	$ (72,219)		$ (269,059)	$ 198,162
1930	Transportation Equipment	20.00%	$ 744,667	$ 926		$ 745,593	$ (699,324)	$ (22,806)		$ (722,130)	$ 23,463
1935	Stores Equipment		$ 47,086			$ 47,086	$ (47,086)			$ (47,086)	$ -
1940	Tools, Shop & Garage Equipment	10.00%	$ 118,530	$ 38,148		$ 156,678	$ (89,634)	$ (9,790)		$ (99,425)	$ 57,254
1945	Measurement & Testing Equipment	20.00%	$ 64,800	$ 5,648		$ 70,448	$ (46,138)	$ (9,038)		$ (55,176)	$ 15,273
1950	Power Operated Equipment		$ -			$ -				$ -	$ -
1955	Communications Equipment		$ -			$ -				$ -	$ -
1955	Communication Equipment (Smart Meters)		$ -			$ -				$ -	$ -
1960	Miscellaneous Equipment		$ -			$ -				$ -	$ -
1975	Load Management Controls Utility Premises		$ -			$ -				$ -	$ -
1980	System Supervisor Equipment		$ -			$ -				$ -	$ -
1985	Miscellaneous Fixed Assets		$ -			$ -				$ -	$ -
1995	Contributions & Grants	4.00%	$ (4,109,851)	$ (867,342)		$ (4,977,193)	$ 1,006,373	$ 199,080		$ 1,205,453	$ (3,771,740)
2055	Construciton Work in Progress		$ -	$ 4,740		$ 4,740				$ -	$ 4,740
			$ -								
	Total		**$23,814,394**	**$1,459,002**	**$(1,265,607)**	**$24,007,789**	**$ (12,409,113)**	**$ (975,166)**	**$ 683,786**	**$(12,700,493)**	**$ 11,307,296**

	Transportation
	Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	
Stores Equipment	
Net Depreciation	$(975,166)

2010 Actual Capital Projects (Exceeding Threshold)

The following Table 2.18 provides Grimsby Power Inc.'s capital additions, exceeding the materiality threshold of $50,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold. In the category "Distribution Plant under Threshold" are approximately 80 different projects which fall under one of the general categories described earlier in this Exhibit.

Table 2.18 2010 Actual Capital Projects

Appendix 2-A
Capital Projects Table

Year: 2010

USoA #	Description	CCA Class	Ridge Road - 2010 rebuild - Part 2	Tx & primary replacment - 4 Rossmore	Cable Injection - 2010	Kemp Road West Rebuild - Part 1	Subdivision Development - Assumed Plant	Resurface Asphalt Parking Lot	Renovate Lunchroom	General Plant Under Threshold	Distribution Plant Under Threshold	Contributions and Grants	Total
1830	Poles, Towers, & Fixtures	47	$ 93,733			$ 76,923					$ 174,906		$ 345,562
1835	Overhead Conductors & Devices	47	$ 73,521	$ 1,519		$ 134,302					$ 109,744		$ 319,085
1840	Underground Conduit	47		$ 24,127		$ 4,407	$ 237,853				$ 26,153		$ 292,541
1845	Underground Conductors & Devices	47		$ 14,411	$ 96,343		$ 114,152				$ 50,283		$ 275,188
1850	Line Transformers	47	$ 68,504	$ 20,274		$ 51,408	$ 222,631				$ 181,077		$ 543,894
1855	Services	47	$ 6,956	$ 936		$ 5,786	$ 248,338				$ 36,029		$ 298,045
1860	Metering	47									$ 76,855		$ 76,855
1908	Buildings & Fixtures	47						$ 26,400	$ 27,981	$ 16,793			$ 71,174
1915	Office Furniture & Equipment	8								$ 7,053			$ 7,053
1920	Computer Equipment Hardware	45								$ 14,365			$ 14,365
1925	Computer Software	12								$ 33,120			$ 33,120
1930	Transportation Equipment	10								$ 926			$ 926
1940	Tools, Shop, & Garage Equipment	8								$ 38,148			$ 38,148
1945	Measurement & Test Equipment	8								$ 5,648			$ 5,648
1955	Communication Equipment	8											$ -
1995	Contributions & Grants	47										-$ 867,342	-$ 867,342
2055	Construction Work in Progress									$ 4,740			$ 4,740
Total			**$ 242,713**	**$ 61,267**	**$ 96,343**	**$ 272,825**	**$ 822,973**	**$ 26,400**	**$ 27,981**	**$ 120,794**	**$ 655,048**	**-$ 867,342**	**$ 1,459,002**

Project 2010: Conversion to 27.6kV: Total cost $515,538

GPI's remaining distribution stations (Kerman and Baker) have been in place for many years and are approaching end of life. GPI's distribution planning strategy has been to eliminate these stations by upgrading the 8kv distribution system to 27kv. Continuing with past efforts the following projects were completed (or partially completed) in 2010:

- Kemp Rd West – Mountain Rd to Woolverton Rd $272,825
- Ridge Rd West – Mountain Rd to Woolverton Rd $242,713

Project 2010: Pad-Mount Replacement Program - Total Cost $61,267

The annual inspection of underground distribution transformers has uncovered what appears to be an increasing trend in defective pad mount transformers. These transformers sit on a concrete pad and this concrete to metal interface is causing severe corrosion of the transformer cases and tanks. These transformers cannot be repaired in the field and as such need to be replaced. This particular project was at 4 Rossmore Street.

Project 2010:* Silicone Injection of Underground Primary Cables - *Total Cost – $96,343

Injecting silicon into existing underground primary cables has proven to extend the life of the cables considerably. This is a continuation of an existing program which began in 2004. This year’s program was in the Peach Tree Estates, Stonegate Manor, and Tindaro Lakeview Subdivisions.

Projects 2010: Building Renovation - Total Cost – $54,381

The office and service centre was designed and built in 1985/86. In 2010 it was determined that repairs, upgrades to building equipment, and general renovating needed to be initiated over a number of years to lessen the impact to the capital budget and maintain the building in a suitable condition for continued use. Projects in 2010 were as follows:

- Renovate the Lunchroom with new ceiling, kitchen, floor, paint, and furniture $27,981
- Re-pave asphalt parking area $26,400

Projects 2010: Smart Meter Mass Deployment - Total Cost – $1,078,520

The mass deployment of Smart Meters to residential and GS<50 customers occurred in 2010. The investment in smart meters was recorded in the capital variance account 1555 and sub-accounts were used to segregate the costs by type for future fixed asset expenditures.

2011 Bridge Year Capital Additions

The 2011 Fixed Asset Continuity Schedule, Table 2.19 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in Grimsby Power Inc.'s Revenue Requirement Model filed with this application.

Table 2.19 2011 Bridge Year Fixed Asset Continuity Schedule

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2011**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land		$ -			$ -				$ -	$ -
47	1808	Buildings		$ -			$ -				$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 143,555			$ 143,555	$ (143,555)			$ (143,555)	$ -
47	1825	Storage Battery Equipment		$ -			$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 7,472,266	$ 505,277		$ 7,977,543	$ (4,318,324)	$ (298,305)		$ (4,616,629)	$ 3,360,914
47	1835	Overhead Conductors & Devices	4.00%	$ 2,115,766	$ 215,534		$ 2,331,300	$ (444,451)	$ (93,260)		$ (537,711)	$ 1,793,589
47	1840	Underground Conduit	4.00%	$ 5,110,882	$ 15,000		$ 5,125,882	$ (2,822,893)	$ (189,268)		$ (3,012,160)	$ 2,113,722
47	1845	Underground Conductors & Devices	4.00%	$ 1,803,450	$ 121,408		$ 1,924,858	$ (379,539)	$ (77,003)		$ (456,542)	$ 1,468,316
47	1850	Line Transformers	4.00%	$ 7,419,309	$ 333,391		$ 7,752,700	$ (3,584,270)	$ (298,740)		$ (3,883,010)	$ 3,869,689
47	1855	Services (Overhead & Underground)	4.00%	$ 1,905,381	$ 54,140		$ 1,959,521	$ (397,145)	$ (78,372)		$ (475,517)	$ 1,484,004
47	1860	Meters	4.00%	$ 388,952	$ 3,803	$(23,834)	$ 368,921	$ (68,285)	$ (14,752)	$ 15,109	$ (67,928)	$ 300,993
47	1860	Meters (Smart Meters)	6.67%	$ -			$ 1,499,556				$ (148,870)	$ 1,350,686
N/A	1905	Land		$ 111,556			$ 111,556				$ -	$ 111,556
CEC	1906	Land Rights		$ -			$ -				$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 755,681	$ 77,240		$ 832,921	$ (343,794)	$ (19,827)		$ (363,621)	$ 469,301
13	1910	Leasehold Improvements		$ -			$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 137,239			$ 137,239	$ (112,165)	$ (4,995)		$ (117,160)	$ 20,079
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -				$ -	$ -
45	1920	Computer Equipment - Hardware	33.33%	$ 129,178	$ 11,500		$ 140,678	$ (98,650)	$ (21,102)		$ (119,752)	$ 20,926
12	1925	Computer Software	20.00%	$ 467,221	$ 222,500		$ 689,721	$ (269,059)	$ (102,154)		$ (371,213)	$ 318,508
10	1930	Transportation Equipment	20.00%	$ 745,593	$ 30,000	$(10,773)	$ 764,820	$ (722,130)	$ (16,982)	$ 10,773	$ (728,339)	$ 36,481
8	1935	Stores Equipment		$ 47,086			$ 47,086	$ (47,086)			$ (47,086)	$ -
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 156,678			$ 156,678	$ (99,425)	$ (8,272)		$ (107,697)	$ 48,981
8	1945	Measurement & Testing Equipment	20.00%	$ 70,448	$ 5,000		$ 75,448	$ (55,176)	$ (7,845)		$ (63,021)	$ 12,428
8	1950	Power Operated Equipment		$ -			$ -				$ -	$ -
8	1955	Communications Equipment		$ -			$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)	20.00%	$ -			$ 10,669				$ (3,201)	$ 7,468
8	1960	Miscellaneous Equipment		$ -			$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -				$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -				$ -	$ -
47	1995	Contributions & Grants	4.00%	$ (4,977,193)	$ (150,000)		$ (5,127,193)	$ 1,205,453	$ 205,088		$ 1,410,541	$ (3,716,652)
WIP	2055	Construciton Work in Progress		$ 4,740	$ (4,740)		$ -				$ -	$ -
				$ -								
		Total		**$24,007,789**	**$1,440,053**	**$(34,607)**	**$ 26,923,461**	**$ (12,700,493)**	**$ (1,025,789)**	**$ 25,882**	**$ (13,852,471)**	**$ 13,070,990**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	
Stores Equipment	
Net Depreciation	$(1,025,789)

2011 Bridge Year Capital Projects

The following Table 2.20 provides Grimsby Power Inc.'s capital additions, exceeding the materiality threshold of $50,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold.

Table 2.20 2011 Bridge Year Capital Projects

Appendix 2-A
Capital Projects Table

Year: 2011

USoA #	Description	CCA Class	Elmtree East Rabbit - C229W to C237R	Padmount Transformers	Primary Cable Silicone Injection	Ridge Road East - Rabbit - to C237R	Service Work	Elmtree - Mountain to Allen	ERP Implementation - Back Office	Replace Existing HVAC Equipment	General Plant Under Threshold	Distribution Plant Under Threshold	Contributions and Grants	Total
1830	Poles, Towers, & Fixtures	47	$ 191,739			$ 94,455		$ 57,973				$ 161,110		$ 505,277
1835	Overhead Conductors & Devices	47	$ 114,084			$ 43,000		$ 43,703				$ 14,747		$ 215,534
1840	Underground Conduit	47										$ 15,000		$ 15,000
1845	Underground Conductors & Devices	47		$ 3,532	$ 112,776							$ 5,100		$ 121,408
1850	Line Transformers	47	$ 114,595	$ 96,390	$ 2,247	$ 77,534		$ 24,912				$ 17,713		$ 333,391
1855	Services	47					$ 54,140							$ 54,140
1860	Metering	47										$ 3,803		$ 3,803
1908	Buildings & Fixtures	47								$ 40,000	$ 32,500			$ 72,500
1915	Office Furniture & Equipment	8												$ -
1920	Computer Equipment Hardware	45									$ 11,500			$ 11,500
1925	Computer Software	12							$ 220,000		$ 2,500			$ 222,500
1930	Transportation Equipment	10									$ 30,000			$ 30,000
1940	Tools, Shop, & Garage Equipment	8												$ -
1945	Measurement & Test Equipment	8									$ 5,000			$ 5,000
1955	Communication Equipment	8												$ -
1995	Contributions & Grants	47											-$ 150,000	-$ 150,000
2055	Construction Work in Progress										-$ 4,740			-$ 4,740
Total			**$ 420,418**	**$ 99,922**	**$ 115,023**	**$ 214,989**	**$ 54,140**	**$ 126,588**	**$ 220,000**	**$ 40,000**	**$ 81,500**	**$ 217,473**	**-$ 150,000**	**$ 1,440,053**

Project 2011: Silicone Injection of Underground Primary Cables - _Total Cost – $115,023_

Injecting silicon into existing underground primary cables has proven to extend the life of the cables considerably. This is a continuation of an existing program.

Projects 2011: Computer Software – ERP Software Solution: Total Cost – $220,000

Currently Grimsby Power Inc. utilizes different software platforms to track and produce financial information. A software called APPX is currently used for accounting purposes including but not limited to payroll, inventory, job costing, etc. All other financial data is kept in various MS Excel Spreadsheets. These financial business processes are very inefficient because they require a manual transfer of data through keying information from one system into the other. This manual transfer creates the potential of error and thus, resources are required to continually check for accuracy. In 2011 Grimsby Power will solve this issue by sourcing and implementing an integrated financial package which will, as best as possible, streamline the entry, manipulation, and reporting of financial data. The end result will increase productivity by shifting resources from transacting the process to evaluating the results of the financial reports produced by the system.

Projects 2011: Building Renovation - Total Cost – $40,000

The office and service centre was designed and built in 1985/86. The existing heating and air conditioning equipment is original and is approaching 25 years old. The system is currently working fine but Grimsby Power Inc. has been advised by its service provider that the equipment is approaching its end of life and that a planned replacement should be initiated.

A major failure would result in a considerable outage with respect to heating and air conditioning. Under this scenario and especially in the winter, working conditions would inhibit normal day to day business activity. A planned approach to the equipments replacement would allow Grimsby Power Inc. to optimize the timing to be least disruptive to staff and ensure business continuity – a proactive approach.

Projects 2011: Smart Meter Deployment - Total Cost – $197,475

The mass deployment of Smart Meters occurred in 2010. However, there were a small number of customers where the meter change could not be completed in the mass deployment. Specifically:

- Residential customers which were difficult to capture due to a number of factors including inside meters, refused to allow meter change, and meters which required modifications to the service in order to install a new meter.
- GS<50 – Most of these meters did not arrive in inventory until 2011.

The smart meters investment will continue in 2011 and smart meters will be installed for the remaining 24 Residential customers or 0.30% and for 195 GS<50 customers or 29.50%. Grimsby Power Inc. is forecasting that these remaining meters will be installed by the end of 2011. The costs estimated at $ 197,475 will be recorded in the capital variance account 1555.

2012 Test Year Capital Additions

The 2012 Fixed Asset Continuity Schedules, Table 2.21 & 2.22 provides a summary of the additions and disposals based on the OEB USoA classification. This schedule may also be found in Grimsby Power Inc.'s Revenue Requirement Model filed with this Application.

Table 2.21 2012 Test Year Fixed Asset Continuity Schedule CGAAP

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2012 CGAAP**

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land		$ -			$ -	$ -			$ -	$ -
47	1808	Buildings		$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 143,555			$ 143,555	$ (143,555)			$ (143,555)	$ -
47	1825	Storage Battery Equipment		$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 7,977,543	$ 246,699		$ 8,224,242	$ (4,616,629)	$ (287,068)		$ (4,903,697)	$ 3,320,545
47	1835	Overhead Conductors & Devices	4.00%	$ 2,331,300	$ 289,322		$ 2,620,622	$ (537,711)	$ (96,144)		$ (633,854)	$ 1,986,768
47	1840	Underground Conduit	4.00%	$ 5,125,882			$ 5,125,882	$ (3,012,160)	$ (186,983)		$ (3,199,143)	$ 1,926,739
47	1845	Underground Conductors & Devices	4.00%	$ 1,924,858	$ 154,611		$ 2,079,469	$ (456,542)	$ (78,544)		$ (535,086)	$ 1,544,383
47	1850	Line Transformers	4.00%	$ 7,752,700	$ 242,292		$ 7,994,992	$ (3,883,010)	$ (299,422)		$ (4,182,433)	$ 3,812,559
47	1855	Services (Overhead & Underground)	4.00%	$ 1,959,521	$ 50,225		$ 2,009,746	$ (475,517)	$ (78,881)		$ (554,398)	$ 1,455,348
47	1860	Meters	4.00%	$ 368,921	$ 13,910		$ 382,831	$ (67,928)	$ (14,897)		$ (82,825)	$ 300,005
47	1860	Meters (Smart Meters)	6.67%	$ 1,499,556	$ 20,920		$ 1,520,476	$ (148,870)	$ (100,668)		$ (249,538)	$ 1,270,938
N/A	1905	Land		$ 111,556			$ 111,556	$ -			$ -	$ 111,556
CEC	1906	Land Rights		$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 832,921	$ 82,570		$ 915,491	$ (363,621)	$ (21,478)		$ (385,099)	$ 530,392
13	1910	Leasehold Improvements		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 137,239			$ 137,239	$ (117,160)	$ (3,925)		$ (121,085)	$ 16,154
8	1915	Office Furniture & Equipment (5 years)		$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equipment - Hardware	33.33%	$ 140,678	$ 17,850		$ 158,528	$ (119,752)	$ (17,131)		$ (136,883)	$ 21,646
12	1925	Computer Software	20.00%	$ 689,721	$ 24,950		$ 714,671	$ (371,213)	$ (100,237)		$ (471,450)	$ 243,222
10	1930	Transportation Equipment	20.00%	$ 764,820	$ 299,000		$ 1,063,820	$ (728,339)	$ (42,446)		$ (770,785)	$ 293,035
8	1935	Stores Equipment		$ 47,086			$ 47,086	$ (47,086)			$ (47,086)	$ -
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 156,678	$ 1,600		$ 158,278	$ (107,697)	$ (6,959)		$ (114,656)	$ 43,622
8	1945	Measurement & Testing Equipment	20.00%	$ 75,448			$ 75,448	$ (63,021)	$ (5,970)		$ (68,990)	$ 6,458
8	1950	Power Operated Equipment		$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	20.00%	$ -	$ 23,700		$ 23,700	$ -	$ (1,185)		$ (1,185)	$ 22,515
8	1955	Communication Equipment (Smart Meters)	20.00%	$ 10,669			$ 10,669	$ (3,201)	$ (2,134)		$ (5,335)	$ 5,335
8	1960	Miscellaneous Equipment		$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment		$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	4.00%	$ (5,127,193)	$ (150,000)		$ (5,277,193)	$ 1,410,541	$ 208,088		$ 1,618,629	$ (3,658,564)
WIP	2055	Construciton Work in Progress		$ -			$ -	$ -			$ -	$ -
				$ -				$ -				
		Total		**$26,923,461**	**$1,317,649**	**$ -**	**$28,241,110**	**$ (13,852,471)**	**$ (1,135,984)**	**$ -**	**$(14,988,455)**	**$ 13,252,655**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	
Stores Equipment	
Net Depreciation	$(1,135,984)

Table 2.22 Test Year Fixed Asset Continuity Schedule MIFRS

Appendix 2-B
Fixed Asset Continuity Schedule

Year: 2012 MIFRS

Cost

OEB	Description	Depreciation Rate	2011 Closing Balance	Capital Contrib Alloc	2012 Opening Balance	Additions	Disposal	Closing Balance
1805	Land		$ -		$ -			$ -
1808	Buildings		$ -		$ -			$ -
1810	Leasehold Improvements		$ -		$ -			$ -
1815	Transformer Station Equipment >50 kV		$ -		$ -			$ -
1820	Distribution Station Equipment <50 kV		$ 143,555		$ 143,555			$ 143,555
1825	Storage Battery Equipment		$ -		$ -			$ -
1830	Poles, Towers & Fixtures	2%	$ 7,977,543	$ (138,912)	$ 7,838,631	$ 204,352		$ 8,042,983
1835	Overhead Conductors & Devices	2%	$ 2,331,300	$ (94,162)	$ 2,237,138	$ 242,816		$ 2,479,954
1840	Underground Conduit	1%	$ 5,125,882	$ (820,427)	$ 4,305,456			$ 4,305,456
1845	Underground Conductors & Devices	3%	$ 1,924,858	$ (778,518)	$ 1,146,340	$ 148,446		$ 1,294,786
1850	OH Line Transformers	3%	$ 5,531,203	$ (1,614,105)	$ 3,917,098	$ 184,446		$ 4,101,544
1850	UG Line Transformers	3%	$ 2,221,496		$ 2,221,496			$ 2,221,496
1855	Services Overhead	2%	$ 178,739		$ 178,739	$ 14,770		$ 193,509
1855	Services Underground	3%	$ 1,780,782	$ (1,515,815)	$ 264,967	$ 28,901		$ 293,868
1860	Meters (Stranded)	4%	$ 19,340	$ (165,254)	$ (145,914)	$ 13,910		$ (132,004)
1860	Meters (Industrial/Commercial)	7%	$ 255,478		$ 255,478			$ 255,478
1860	Meters (Other CT's & PT's	3%	$ 94,103		$ 94,103			$ 94,103
1860	Meters (Smart Meters)	7%	$ 1,499,556		$ 1,499,556	$ 19,529		$ 1,519,085
1905	Land		$ 111,556		$ 111,556			$ 111,556
1906	Land Rights		$ -		$ -			$ -
1908	Buildings	2%	$ 622,852		$ 622,852	$ 82,570		$ 705,422
1908	Paving/Fencing	3%	$ 56,223		$ 56,223			$ 56,223
1908	Other Fixtures	4%	$ 153,846		$ 153,846			$ 153,846
1910	Leasehold Improvements		$ -		$ -			$ -
1915	Office Furniture & Equipment (10 years)	10%	$ 137,239		$ 137,239			$ 137,239
1915	Office Furniture & Equipment (5 years)		$ -		$ -			$ -
1920	Computer Equipment - Hardware	20%	$ 140,678		$ 140,678	$ 17,850		$ 158,528
1925	Computer Software	20%	$ 689,721		$ 689,721	$ 24,950		$ 714,671
1930	Transportation Equipment	7%	$ 764,820		$ 764,820	$ 299,000		$ 1,063,820
1935	Stores Equipment		$ 47,086		$ 47,086			$ 47,086
1940	Tools, Shop & Garage Equipment	10%	$ 156,678		$ 156,678	$ 1,600		$ 158,278
1945	Measurement & Testing Equipment	20%	$ 75,448		$ 75,448			$ 75,448
1950	Power Operated Equipment		$ -		$ -			$ -
1955	Communications Equipment	20%	$ -		$ -	$ 23,700		$ 23,700
1955	Communication Equipment (Smart Meters)	20%	$ 10,669		$ 10,669			$ 10,669
1960	Miscellaneous Equipment		$ -		$ -			$ -
1975	Load Management Controls Utility Premises		$ -		$ -			$ -
1980	System Supervisor Equipment		$ -		$ -			$ -
1985	Miscellaneous Fixed Assets		$ -		$ -			$ -
1995	Contributions & Grants		$ (5,127,193)	$ 5,127,193	$ -			$ -
2005	Property under Capital Lease		$ -		$ -			$ -
			$ -					$ -
	Total		**$ 26,923,461**	**$ -**	**$ 26,923,461**	**$1,306,840**	**$ -**	**$ 28,230,301**

Accumulated Depreciation

OEB	Description	2011 Closing Balance	Capital Contrib Alloc	2012 Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	$ -		$ -			$ -	$ -
1808	Buildings	$ -		$ -			$ -	$ -
1810	Leasehold Improvements	$ -		$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -			$ -	$ -
1820	Distribution Station Equipment <50 kV	$ (143,555)		$ (143,555)			$ (143,555)	$ -
1825	Storage Battery Equipment	$ -		$ -			$ -	$ -
1830	Poles, Towers & Fixtures	$ (4,616,629)	$ 38,216	$ (4,578,413)	$(116,944)		$ (4,695,357)	$ 3,347,627
1835	Overhead Conductors & Devices	$ (537,711)	$ 25,905	$ (511,806)	$ (38,103)		$ (549,909)	$ 1,930,045
1840	Underground Conduit	$ (3,012,160)	$ 225,707	$ (2,786,453)	$ (55,059)		$ (2,841,512)	$ 1,463,944
1845	Underground Conductors & Devices	$ (456,542)	$ 214,178	$ (242,364)	$ (33,771)		$ (276,136)	$ 1,018,651
1850	OH Line Transformers	$ (3,883,010)	$ 444,056	$ (3,438,954)	$(103,458)		$ (3,542,412)	$ 559,132
1850	UG Line Transformers	$ -		$ -	$ (74,050)		$ (74,050)	$ 2,147,446
1855	Services Overhead	$ (475,517)	$ 417,015	$ (58,502)	$ (2,892)		$ (61,393)	$ 132,116
1855	Services Underground	$ -		$ -	$ (6,985)		$ (6,985)	$ 286,883
1860	Meters (Stranded)	$ (67,928)	$ 45,463	$ (22,465)	$ (1,052)		$ (23,517)	$ (155,521)
1860	Meters (Industrial/Commercial)	$ (148,870)		$ (148,870)	$ (5,786)		$ (154,656)	$ 100,822
1860	Meters (Other CT's & PT's	$ -		$ -	$ (2,689)		$ (2,689)	$ 91,414
1860	Meters (Smart Meters)	$ -		$ -	$(100,621)		$ (100,621)	$ 1,418,464
1905	Land	$ -		$ -			$ -	$ 111,556
1906	Land Rights	$ -		$ -			$ -	$ -
1908	Buildings	$ (323,883)		$ (323,883)	$ (12,457)		$ (336,340)	$ 369,082
1908	Paving/Fencing	$ (28,257)		$ (28,257)	$ (1,406)		$ (29,663)	$ 26,560
1908	Other Fixtures	$ (11,480)		$ (11,480)	$ (7,805)		$ (19,286)	$ 134,560
1910	Leasehold Improvements	$ -		$ -			$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ (117,160)		$ (117,160)	$ (3,925)		$ (121,085)	$ 16,154
1915	Office Furniture & Equipment (5 years)	$ -		$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ (119,752)		$ (119,752)	$ (10,278)		$ (130,031)	$ 28,498
1925	Computer Software	$ (371,213)		$ (371,213)	$(100,237)		$ (471,450)	$ 243,222
1930	Transportation Equipment	$ (728,339)		$ (728,339)	$ (14,149)		$ (742,488)	$ 321,333
1935	Stores Equipment	$ (47,086)		$ (47,086)			$ (47,086)	$ -
1940	Tools, Shop & Garage Equipment	$ (107,697)		$ (107,697)	$ (6,959)		$ (114,656)	$ 43,622
1945	Measurement & Testing Equipment	$ (63,021)		$ (63,021)	$ (5,970)		$ (68,990)	$ 6,458
1950	Power Operated Equipment	$ -		$ -			$ -	$ -
1955	Communications Equipment	$ -		$ -	$ (2,370)		$ (2,370)	$ 21,330
1955	Communication Equipment (Smart Meters)	$ (3,201)		$ (3,201)	$ (2,134)		$ (5,335)	$ 5,335
1960	Miscellaneous Equipment	$ -		$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -			$ -	$ -
1980	System Supervisor Equipment	$ -		$ -			$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -			$ -	$ -
1995	Contributions & Grants	$ 1,410,541	$ (1,410,541)	$ -			$ -	$ -
2005	Property under Capital Lease	$ -		$ -			$ -	$ -
		$ -		$ -			$ -	$ -
	Total	**$ (13,852,471)**	**$ 0**	**$ (13,852,471)**	**$(709,099)**	**$ -**	**$ (14,561,570)**	**$ 13,668,731**

	Transportation
	Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	
Stores Equipment	
Net Depreciation	$(709,099)

2012 Test Year Proposed Capital Projects

The following Table 2.23 & 2.24 provides Grimsby Power Inc.'s capital additions, exceeding the materiality threshold of $50,000, by project, project type and USoA as well as the total projects, by USoA that fall under the materiality threshold.

Table 2.23 2012 Test Year Proposed Capital Projects CGAAP

Appendix 2-A
Capital Projects Table

Year: 2012 CGAAP

USoA #	Description	CCA Class	Maple Avenue Conversion to 27.6kV	Padmount Transformer Replacement Program	Primary Cable Silicon Injection	Ridge Road East Between Mountain and Park - Part 1 - Mountain to Russ	Ridge Road East Between Mountain and Park - Part 2 - Russ to Park	Sobie Road Rebuild - Transformer 6352 to Fairbrother Road	Woolverton Road Rebuild - Ridge Road West to Main Street West	Bucket Truck - 55ft Aerial Device and Fiberglass Body	Renovate Engineering Office Area	General Plant Under Threshold	Distribution Plant Under Threshold	Contributions and Grants	Total
1830	Poles, Towers, & Fixtures	47	$ 10,673			$ 21,756	$ 13,482	$ 71,110	$ 86,656				$ 43,022		$ 246,699
1835	Overhead Conductors & Devices	47	$ 31,004			$ 28,013	$ 25,857	$ 65,194	$ 85,334				$ 53,920		$ 289,322
1840	Underground Conduit	47													$ -
1845	Underground Conductors & Devices	47	$ 4,464	$ 4,402	$ 117,731								$ 28,014		$ 154,611
1850	Line Transformers	47	$ 13,277	$ 103,379	$ 2,345	$ 10,544	$ 5,302	$ 56,074	$ 13,138				$ 38,233		$ 242,292
1855	Services	47				$ 1,886	$ 3,106						$ 45,233		$ 50,225
1860	Metering	47											$ 13,910		$ 13,910
1860	Metering (Smart Meters)												$ 20,920		$ 20,920
1908	Buildings & Fixtures	47									$ 82,570				$ 82,570
1915	Office Furniture & Equipment	8													$ -
1920	Computer Equipment Hardware	45										$ 17,850			$ 17,850
1925	Computer Software	12										$ 24,950			$ 24,950
1930	Transportation Equipment	10								$ 275,000		$ 24,000			$ 299,000
1940	Tools, Shop, & Garage Equipment	8										$ 1,600			$ 1,600
1945	Measurement & Test Equipment	8													$ -
1955	Communication Equipment	8										$ 23,700			$ 23,700
1995	Contributions & Grants	47												$ (150,000)	$ (150,000)
Total			**$ 59,418**	**$ 107,781**	**$ 120,076**	**$ 62,199**	**$ 47,747**	**$ 192,378**	**$ 185,128**	**$ 275,000**	**$ 82,570**	**$ 92,100**	**$ 243,252**	**-$ 150,000**	**$ 1,317,649**

Table 2.24 2012 Test Year Proposed Capital Projects MIFRS

Appendix 2-A
Capital Projects Table

Tables in the format outlined below covering all relevant accounts should be submitted for the Test Year, Bridge Year **and** the relevant historical years.

Year: 2012 IFRS

USoA #	Description	CCA Class	Maple Avenue Conversion to 27.6kV	Padmount Transformer Replacement Program	Primary Cable Silicon Injection	Ridge Road East Between Mountain and Park - Part 1 - Mountain to Russ	Ridge Road East Between Mountain and Park - Part 2 - Russ to Park	Sobie Road Rebuild - Transformer 6352 to Fairbrother Road	Woolverton Road Rebuild - Ridge Road West to Main Street West	Bucket Truck - 55ft Aerial Device and Fiberglass Body	Renovate Engineering Office Area	General Plant Under Threshold	Distribution Plant Under Threshold	Total
1830	Poles, Towers, & Fixtures	47	$ 8,301			$ 17,917	$ 10,283	$ 57,973	$ 76,912				$ 32,966	$ 204,352
1835	Overhead Conductors & Devices	47	$ 26,115			$ 24,414	$ 20,848	$ 55,396	$ 72,154				$ 43,889	$ 242,816
1840	Underground Conduit	47												$ -
1845	Underground Conductors & Devices	47	$ 3,593	$ 3,901	$ 114,886								$ 26,066	$ 148,446
1850	Line Transformers	47	$ 10,002	$ 79,758	$ 1,752	$ 8,149	$ 3,993	$ 41,859	$ 9,555				$ 29,378	$ 184,446
1855	Services	47				$ 1,703	$ 2,635						$ 39,333	$ 43,671
1860	Metering	47											$ 13,910	$ 13,910
1860	Metering (Smart Meters)	47											$ 19,529	$ 19,529
1908	Buildings & Fixtures	47									$ 82,570			$ 82,570
1915	Office Furniture & Equipment	8												$ -
1920	Computer Equipment Hardware	45										$ 17,850		$ 17,850
1925	Computer Software	12										$ 24,950		$ 24,950
1930	Transportation Equipment	10								$ 275,000		$ 24,000		$ 299,000
1940	Tools, Shop, & Garage Equipment	8										$ 1,600		$ 1,600
1945	Measurement & Test Equipment	8												$ -
1955	Communication Equipment	8										$ 23,700		$ 23,700
1995	Contributions & Grants	47												$ -
Total			**$ 48,011**	**$ 83,659**	**$ 116,638**	**$ 52,183**	**$ 37,759**	**$ 155,228**	**$ 158,621**	**$ 275,000**	**$ 82,570**	**$ 92,100**	**$ 205,071**	**$ 1,306,840**

For the purpose of project descriptions costs will be shown in MIFRS format only.

Project 2012: Conversion to 27.6kV: Total cost $451,802

GPI's remaining distribution stations (Kerman and Baker) have been in place for many years and are approaching end of life. GPI's distribution planning strategy has been to eliminate these stations by upgrading the 8kv distribution system to 27kv. Continuing with past efforts the following projects are slated for 2012:

- Sobie Road – Transformer 6352 to Fairbrother Road $155,228
- Woolverton Road – Ridge Road West to Main Street West $158,621
- Ridge Road East – Mountain to Park – Part 1 $52,183
- Ridge Road East – Mountain to Park – Part 2 $37,759
- Maple Avenue $48,011

Project 2012: Pad-Mount Replacement Program - Total Cost $83,659

The annual inspection of underground distribution transformers has uncovered what appears to be an increasing trend in defective pad mount transformers. These transformers sit on a concrete pad and this concrete to metal interface is causing severe corrosion of the transformer cases and tanks. These transformers cannot be repaired in the field and as such need to be replaced.

Project 2012:* Silicone Injection of Underground Primary Cables - *Total Cost – $116,638

Injecting silicon into existing underground primary cables has proven to extend the life of the cables considerably. This is a continuation of an existing program.

Projects 2012: Building Renovation - Total Cost – $82,570

The office and service centre was designed and built in 1985/86. The first floor of the office space has not been updated. A refurbishment program began in 2010 with the lunchroom renovation, in 2011 with the men's locker room and washroom renovation and in 2012 the main Engineering Department area is slated. The renovation includes new:

- Flooring
- Paint
- Suspended Ceiling
- Office Furniture

Projects 2012: Bucket Truck - Total Cost – $275,000

Grimsby Power Inc. manages the replacement of vehicles in accordance with the schedule provided in Table 2.26 below and subject to the continued operation of and the costs of maintenance, makes the final decision as to replacement the year prior to the scheduled replacement. Grimsby Power Inc.'s utilizes an evaluation matrix shown in Table 2.25 below to guide its decisions about truck replacement. This analysis shows that three trucks should be reviewed for a replacement decision. Of the three trucks, 2011's budget analysis shows that only Trucks # 15 and 16, originally purchased in 1988 and 1989, are in need of replacement. As the usage on these vehicles is low only one truck will be purchased and it will be a 55ft Material Handling Aerial Device.

Table 2.25 Fleet Evaluation Matrix

Factor	Fleet Evaluation Matrix for 2011 Budget Process					Fleet Evaluation Matrix for 2011 Budget Process									
	Description of Evaluation Criteria					Large Trucks					Small Trucks				
						9	10	15	16		1	12	19	20	
Age	One point for each year of service based on in service date					16	8	23	22		6	3	4	4	
Mileage	One point for each 16093 kilometers (10000miles) of use					3	6	3	6		6	2	2	3	
Type of Service	Light duty - Small Vehicles - Engineering or Administrator Use - Large vehicles - on road use only and lightly loaded.	n/a	Medium Duty - Small Vehicles - trucks used by trades which are commonly loaded - Large vehicles - mainly on road use and with average payload	n/a	Heavy Duty - Small & Large Vehicles - Trades use and commonly loaded for road and off road use	3	5	3	3		5	1	1	1	
Reliability	Repair once every 3 months or less	n/a	Repair two or three times in 3 month period	n/a	Repair two or more times per month on average	1	1	1	3		1	1	1	1	
Maintenance and Repair Costs	Accumulated cost as compared to original purchase cost - ≤ 20%	Accumulated cost as compared to original purchase cost - > 20% & ≤ 47%	Accumulated cost as compared to original purchase cost - > 47% & ≤ 74%	Accumulated cost as compared to original purchase cost - > 74% & < 100%	Accumulated cost as compared to original purchase cost - ≥ 100%	3	3	4	4		1	1	1	1	
	Take into consideration body condition, rust, interior condition, anticipated repairs, and accident history														
Condition	Excellent - Truck has no signs of deterioration and is close to like new condition	Very Good - Truck is no longer in new condition but is still in very good shape	Good - Truck has signs of regular use	Fair - Truck is showing signs of early deterioration with advanced signs of rust, & worn interior components.	Poor - Truck has signs of rust perforation, seat covers are worn thru, and repairs have been postponed due to age and cost benefit.	3	3	3	3		3	3	3	3	
					Total Score	**29**	**26**	**37**	**41**	**0**	**22**	**11**	**12**	**13**	**0**

Scoring Results	
Point Ranges	**Action**
Under 18	Excellent - Continue to Monitor
18-22	Good - Continue to Monitor
23-27	Qualifies for Replacement - Schedule Detailed Evaluation
over 27	Needs Immediate Consideration - Perform Detailed Evaluation

Table 2.26 Fleet Replacement Schedule

					Replacement Schedule																	
Unit #	Year	In Service Date	Original Book Value	Mounted Device		2010		2011		2012		2013		2014		2015		2016		2017		2018
Large Trucks (15 Year Cycle)																						
15	1988	Nov 23/88	$157,370	Altec AM-600 - MHAD Double Bucket	S																	
16	1989	Sep 15/89	$124,501	Altec AM-450 - MHAD - Double Bucket	S				X	$ 275,000												
9	1995	Jul 17/95	$205,925	Altec - RBD - Digger Derrick	S								X	$ 330,000								
Medium Trucks (12 Year Cycle)																						
10	2003	Apr 16/03	$134,551	Versalift SST - ML - Single Bucket											S		X	$ 175,000				
Small Trucks (8 Year Cycle)																						
1	2005	Dec xx/05	$27,128	Pickup							S	$ 35,000										
12	2008	Feb xx/09	$21,795	Van													S		X	$ 35,000		
19	2007	Mmm xx/07	$22,173	Mini Van											S				X	$ 30,000		
20	2007	Mmm xx/07	$26,409	SUV											S				X	$ 30,000		
Trailers (As Required based on Condition)																						
	1991	Jan 01/91	$10,773	T.J. Welding Ltd			X	$ 30,000														
21	1993	Apr xx/93		Hitchman					X	$ 20,000												
	2008	Aug 06/08	$10,009	Wheeler Reeler (Lightning Sales)																		
Forklifts & Equipment (As Required based on Condition)																						
	1997			Nissan																		
						$ -		$ 30,000		$ 295,000		$ 35,000		$ 330,000		$ -		$ 175,000		$ 95,000		$ -

ASSET MANAGEMENT PLAN SUMMARY & FUTURE CAPITAL PLANS

The purpose of the Distribution Asset Management Plan (DAMP) is to outline how Grimsby Power Inc. (GPI) will develop, manage, and maintain its distribution system equipment to provide a safe, reliable, efficient, and cost effective distribution system.

The DAMP identifies the major initiatives and projects to be undertaken over the planning period to meet customer and stakeholder requirements. The plan identifies the key components to be considered and outlines GPI's decision process with respect to its assets. Key areas of the plan are as follows:

- Planning Horizon
- Key Assumptions
- Identification of Assets
- Risk Management
- Asset Strategy
- Accountabilities
- Key Systems and Processes
- Inspection and Maintenance Program
- Service Quality
- Sustainment Strategies
- Forecasted Budgets
- Project Prioritization Methodology
- Future Plans

Future capital plans have been predicted by forecasting the replacement of assets in any given year utilizing a typical useful life and average cost per asset type. Detail about future capital plans are identified in Grimsby Power Inc.'s DAMP included as Appendix 2.1 of this exhibit.

ACCUMULATED DEPRECIATION

Grimsby Power Inc. uses the straight line method of amortization to determine the depreciation expense for all distribution assets on a pooled basis and identifiable assets individually. A full year's amortization is calculated on a straight line basis over estimated useful life of the asset. Grimsby Power Inc. follows the amortization schedule provided at Schedule B of the OEB's 2007 Electricity Distribution Rate Handbook.

For the purposes of this rate application, Grimsby Power Inc. used the half year rule for calculating depreciation expense for the 2012 Test Year. Details of Grimsby Power Inc.'s depreciation by account number are provided in the Fixed Asset Continuity Schedules as set out above beginning with Table 2.9.

Further information on Grimsby Power Inc.'s depreciation expenses and continuity schedules are provided in Exhibit 4.

WORKING CAPITAL CALCULATION

Overview

Grimsby Power Inc.'s working capital allowance is forecast to be $2,967,091 for the 2012 Test Year. Grimsby Power Inc. has not undertaken a Working Capital lead-lag study pending OEB direction and as such has calculated its working capital allowance using the 15% Allowance Approach as noted in the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, dated June 28, 2010 – Section 2.3.4. Grimsby Power Inc. submits that its working capital calculations are not only consistent with the Filing Guidelines but are also consistent with OEB Decisions in distributors' cost of service applications approved in 2009, 2010 and 2011, where a utility specific lead-lag study had not been undertaken. The working capital allowance is based on Grimsby Power Inc.'s proposed 2012 Test Year controllable expenses and cost of power. Grimsby Power Inc. has provided a summary of the calculations by the OEB's USoA classification for each of 2004 Actual to 2010 Actual, the 2011 Bridge Year, the 2012 Test Year (CGAAP), and the

2012 Test Year (MIFRS) in Table 2.26 below. The 2011 Bridge Year and 2012 Test Year Cost of Power calculations are provided in Tables 2.29 through 2.32 below.

Detail

Table 2.28 sets out Grimsby Power Inc.'s year over year working capital variances for the 2006 Board Approved, the five years 2006 to 2010 Actuals, 2011 Bridge Year, 2012 Test Year (CGAAP), and 2012 Test Year (MIFRS) (Table 2.27 below has been repeated here from Table 2.2 above for ease of comparison of the working capital variances). Grimsby Power Inc. notes that the 2006 Board Approved working capital was determined through the 2006 EDR process and is based on the 2004 year end OM&A and cost of power adjusted for Tier 1 Adjustments. Accordingly, the variance between 2006 Actual and 2006 Board Approved spans a two-year period. As apparent from Table 2.28, the major variances in the change in working capital is in the year over year cost of power and in the later years the increase in OM&A Expenses. The detailed working capital calculations by OEB USoA classification are provided in Table 2.29 below and the variances in the OM&A accounts is discussed in further detail in Exhibit 4.

Table 2.27 Summary of Working Capital Calculations

Description	2004 Actual	2005 Actual	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 CGAAP Test Year	2012 IFRS Test Year
Cost of Power	10,854,178	13,061,041	11,033,351	12,816,602	13,500,381	13,124,063	13,435,689	15,351,169	16,712,098	17,156,811	17,156,811
Operations	207,528	163,334	207,528	187,438	187,089	200,472	197,350	179,324	271,866	283,721	478,166
Maintenance	219,107	360,029	219,107	225,316	271,420	409,935	380,246	397,852	418,385	489,114	460,674
Billing & Collecting	401,581	427,302	399,757	407,642	483,317	487,755	463,965	506,789	504,524	590,270	588,252
Community Relations	12,525	26,551	5,388	53,288	80,754	33,426	11,428	11,749	16,500	12,500	12,500
Administrative & General Expenses	542,129	550,918	690,965	599,394	663,462	634,397	687,172	684,872	838,270	1,052,715	1,052,548
Other - LEAP program									3,974	4,117	4,117
Taxes Other than Income Taxes	25,001	17,008	28,221	36,488	31,990	27,150	30,314	25,130	27,000	27,540	27,540
Working Capital	12,262,050	14,606,183	12,584,317	14,326,168	15,218,415	14,917,198	15,206,163	17,156,886	18,792,616	19,616,788	19,780,608
Working Capital Allowance - 15%	1,839,308	2,190,927	1,887,648	2,148,925	2,282,762	2,237,580	2,280,924	2,573,533	2,818,892	2,942,518	2,967,091

Table 2.28 Working Capital Variances

Description	2006 Actual Variance from 2006 OEB Approved	2007 Actual Variance from 2006 Actual	2008 Actual Variance from 2007 Actual	2009 Actual Variance from 2008 Actual	2010 Actual Variance from 2009 Actual	2011 Bridge Year Variance from 2010 Actual	2012 CGAAP Test Year Variance from 2011 Bridge Year	2012 IFRS Test Year Variance from 2011 Bridge Year
Cost of Power	1,783,251	683,779	(376,319)	311,626	1,915,480	1,360,929	444,713	444,713
Operations	(20,090)	(349)	13,383	(3,122)	(18,026)	92,542	11,855	206,300
Maintenance	6,209	46,105	138,515	(29,689)	17,606	20,533	70,729	42,289
Billing & Collecting	7,885	75,676	4,438	(23,791)	42,825	(2,265)	85,746	83,728
Community Relations	47,900	27,466	(47,328)	(21,999)	322	4,751	(4,000)	(4,000)
Administrative & General Expenses	(91,571)	64,068	(29,065)	52,775	(2,300)	153,398	214,445	214,278
Other - LEAP program			-	-	-	3,974	143	143
Taxes Other than Income Taxes			(4,841)	3,164	(5,183)	1,870	540	540
Working Capital	1,741,851	892,247	(301,217)	288,964	1,950,723	1,635,731	824,172	987,992

Table 2.29 Detailed Working Capital Calculations

	Description	2006 Actual	Allowance for Working	2007 Actual	Allowance for Working	2008 Actual	Allowance for Working	2009 Actual	Allowance for Working	2010 Actual	Allowance for Working	2011 Bridge Year	Allowance for Working	2012 CGAAP Test Year	Allowance for Working	2012 IFRS Test Year	Allowance for Working
Rate Used for Working Capital Allowance			15%		15%		15%		15%		15%		15%		15%		15%
Operations																	
5005	Operation_Supervision_and_Engineering	13,468	2,020	22,491	3,374	25,442	3,816	22,962	3,444	24,379	3,657	63,825	9,574	60,649	9,097	60,649	9,097
5012	Station_Buildings_and_Fixtures_Expenses	1,784	268	2,680	402	4,244	637	340	51	775	116						
5020	Overhead_Distribution_Lines_and_Feeders_Operation_Labour	37,049	5,557	45,511	6,827	60,675	9,101	55,554	8,333	68,827	10,324	28,427	4,264	38,630	5,795	37,599	5,640
5025	Overhead_Distribution_Lines_and_Feeders_Operation_Supplies_and_Exper	19,265	2,890	20,809	3,121	22,106	3,316	19,133	2,870	16,330	2,450	9,650	1,448	12,928	1,939	12,010	1,802
5035	Overhead_Distribution_Transformers_Operation	5,045	757	1,132	170	4,437	666	712	107	2,031	305						
5040	Underground_Distribution_Lines_and_Feeders_Operation_Labour	39,275	5,891	37,010	5,551	30,904	4,636	37,269	5,590	29,597	4,440	32,874	4,931	35,403	5,310	31,158	4,674
5045	Underground_Distribution_Lines_and_Feeders_Operation_Supplies_and_Ex	36	5	1,334	200	729	109	210	31	62	9						
5055	Underground_Distribution_Transformers_Operation	1,294	194	2,659	399	1,115	167	57	9								
5065	Meter_Expenses	33,901	5,085	14,082	2,112	15,944	2,392	23,875	3,581	6,645	997						
5070	Customer_Premises_Operating_Labour	5,243	786	12,700	1,905	8,203	1,230	8,048	1,207	8,307	1,246	4,687	703	5,383	807	4,701	705
5075	Customer_Premises_Operating_Materials_and_Expenses	35	5	10	2					123	18						
5085	Miscellaneous_Distribution_Expenses	18,144	2,722			13,774	2,066	16,291	2,444	12,572	1,886	106,903	16,035	104,970	15,746	306,291	45,944
5095	Overhead_ Distribution_ Lines_and Feeders_ Rental_ Paid	12,900	1,935	26,672	4,001	12,900	1,935	12,900	1,935	9,675	1,451	25,500	3,825	25,758	3,864	25,758	3,864
	Operations - Sub -Total	**187,438**	**28,116**	**187,089**	**28,063**	**200,472**	**30,071**	**197,350**	**29,602**	**179,324**	**26,899**	**271,866**	**40,780**	**283,721**	**42,558**	**478,166**	**71,725**
Maintenance																	
5105	Maintenance_Supervision_and_Engineering	19,823	2,973	24,781	3,717	35,678	5,352	31,818	4,773	33,342	5,001	55,325	8,299	51,441	7,716	51,441	7,716
5114	Maintenance_of_Buildings_and_Stations_Distribution_Stations	2,951	443	5,882	882	3,697	555	1,575	236	2,027	304	800	120	816	122	816	122
5120	Maintenance_of_Poles_Towers_and_Fixtures	37,882	5,682	39,055	5,858	47,202	7,080	35,802	5,370	69,241	10,386	64,082	9,612	43,421	6,513	40,114	6,017
5125	Maintenance_of_Overhead_Conductors_and_Devices	58,353	8,753	41,876	6,281	72,404	10,861	72,129	10,819	79,075	11,861	99,159	14,874	90,730	13,610	82,836	12,425
5130	Maintenance_of_Overhead_Services	33,216	4,982	36,780	5,517	50,945	7,642	54,578	8,187	57,337	8,601	40,193	6,029	75,842	11,376	67,233	10,085
5135	Overhead_Distribution_Lines_and_Feeders_Right_of_Way	39,542	5,931	51,377	7,707	59,110	8,866	69,375	10,406	51,225	7,684	40,268	6,040	77,873	11,681	77,653	11,648
5145	Maintenance_of_Underground_Conduit	(623)	(93)	132	20	646	97	8,196	1,229	(76)	(11)						
5150	Maintenance_of_Underground_Conductors_and_Devices	402	60	16,997	2,550	15,241	2,286	3,003	450	24,137	3,621						
5155	Maintenance_of_Underground_Services	9,725	1,459	12,812	1,922	17,825	2,674	12,685	1,903	8,750	1,313	11,162	1,674	15,029	2,254	13,817	2,073
5160	Maintenance_of_Line_Transformers	23,619	3,543	40,516	6,077	101,294	15,194	83,405	12,511	63,243	9,487	93,164	13,975	85,784	12,868	78,586	11,788
5175	Maintenance_of_Meters	425	64	1,212	182	5,894	884	7,680	1,152	9,550	1,432	14,232	2,135	48,178	7,227	48,178	7,227
	Maintenance - Sub -Total	**225,316**	**33,797**	**271,420**	**40,713**	**409,935**	**61,490**	**380,246**	**57,037**	**397,852**	**59,678**	**418,385**	**62,758**	**489,114**	**73,367**	**460,674**	**69,101**

	Description	2006 Actual	Allowance for Working	2007 Actual	Allowance for Working	2008 Actual	Allowance for Working	2009 Actual	Allowance for Working	2010 Actual	Allowance for Working	2011 Bridge Year	Allowance for Working	2012 CGAAP Test Year	Allowance for Working	2012 IFRS Test Year	Allowance for Working
Rate Used for Working Capital Allowance			15%		15%		15%		15%		15%		15%		15%		15%
Billing and collecting																	
5305	Supervision	8,214	1,232	10,000	1,500	9,228	1,384	14,328	2,149	9,824	1,474	4,660	699	4,284	643	4,284	643
5310	Meter_Reading_Expense	111,485	16,723	106,073	15,911	113,978	17,097	100,061	15,009	130,653	19,598	87,665	13,150	168,662	25,299	166,644	24,997
5315	Customer_Billing	253,712	38,057	308,072	46,211	303,930	45,590	298,993	44,849	306,360	45,954	357,358	53,604	360,711	54,107	360,711	54,107
5320	Collecting	62,378	9,357	58,275	8,741	59,514	8,927	54,583	8,187	55,130	8,269	42,935	6,440	43,983	6,597	43,983	6,597
5325	Collecting_Cash_Over_and_Short			(243)	(36)	(63)	(9)	(70)	(10)	643	96	5,906	886	6,630	995	6,630	995
5335	Bad_Debt_Expense	(28,147)	(4,222)	1,140	171	1,167	175	(3,931)	(590)	4,180	627	6,000	900	6,000	900	6,000	900
	Billing and Collecting - Sub -Total	**407,642**	**61,146**	**483,317**	**72,498**	**487,755**	**73,163**	**463,965**	**69,595**	**506,789**	**76,018**	**504,524**	**75,679**	**590,270**	**88,541**	**588,252**	**88,238**
Community Relations																	
5410	Community_Relations_Sundry	10,846	1,627	11,670	1,750	11,836	1,775	11,428	1,714	11,649	1,747	12,000	1,800	9,000	1,350	9,000	1,350
5415	Energy_Conservation	41,058	6,159	67,080	10,062	19,894	2,984										
	Community Relations - Sub -Total	**51,904**	**7,786**	**78,750**	**11,813**	**31,730**	**4,760**	**11,428**	**1,714**	**11,649**	**1,747**	**12,000**	**1,800**	**9,000**	**1,350**	**9,000**	**1,350**
Sales Expenses																	
5515	Advertising Expenses	1,384	208	2,004	301	1,696	254			100	15	4,500	675	3,500	525	3,500	525
	Sales - Sub -Total	**1,384**	**208**	**2,004**	**301**	**1,696**	**254**			**100**	**15**	**4,500**	**675**	**3,500**	**525**	**3,500**	**525**
Administrative and General Expenses																	
5605	Executive_Salaries_and_Expenses	60,675	9,101	98,625	14,794	105,328	15,799	95,345	14,302	37,816	5,672	145,260	21,789	159,420	23,913	159,420	23,913
5610	Management_Salaries_and_Expenses	219,329	32,899	219,564	32,935	197,407	29,611	217,887	32,683	252,178	37,827	211,280	31,692	228,940	34,341	228,940	34,341
5615	General_Administrative_Salaries_and_Expenses	87,264	13,090	162,166	24,325	179,016	26,852	155,885	23,383	175,180	26,277	172,430	25,865	226,219	33,933	226,219	33,933
5620	Office_Supplies_and_Expenses	43,289	6,493	46,507	6,976	47,473	7,121	39,985	5,998	42,000	6,300	32,325	4,849	44,861	6,729	44,694	6,704
5630	Outside_Services_Employeed	86,805	13,021	44,396	6,659	12,131	1,820	52,577	7,887	43,503	6,525	47,920	7,188	86,856	13,028	86,856	13,028
5635	Property Insurance	4,139	621	4,323	648	4,107	616	8,373	1,256	8,642	1,296	22,000	3,300	23,307	3,496	23,307	3,496
5640	Injuries_and_Damages	16,732	2,510	18,121	2,718	18,631	2,795	16,794	2,519	13,144	1,972						
5645	Employee_Pensions_and_Benefits											5,880	882	5,998	900	5,998	900
5655	Regulatory_Expense	33,993	5,099	24,865	3,730	23,361	3,504	25,722	3,858	26,173	3,926	26,500	3,975	59,520	8,928	59,520	8,928
5665	Miscellaneous_General_Expenses							19,705	2,956	21,455	3,218	88,790	13,319	99,401	14,910	99,401	14,910
5675	Maintenance_of_General_Plant	42,818	6,423	40,438	6,066	42,334	6,350	50,172	7,526	60,004	9,001	80,885	12,133	113,093	16,964	113,093	16,964
5680	Electrical_Safety_Authority_Fees	4,351	653	4,458	669	4,609	691	4,726	709	4,777	717	5,000	750	5,100	765	5,100	765
	Administrative and General Expenses - Sub -Total	**599,394**	**89,909**	**663,462**	**99,519**	**634,397**	**95,160**	**687,172**	**103,076**	**684,872**	**102,731**	**838,270**	**125,741**	**1,052,715**	**157,907**	**1,052,548**	**157,882**

	Description	2006 Actual	Allowance for Working	2007 Actual	Allowance for Working	2008 Actual	Allowance for Working	2009 Actual	Allowance for Working	2010 Actual	Allowance for Working	2011 Bridge Year	Allowance for Working	2012 CGAAP Test Year	Allowance for Working	2012 IFRS Test Year	Allowance for Working
Property Tax																	
6105	Taxes_Other_than_Income Taxes	36,488	5,473	31,990	4,799	27,150	4,072	30,314	4,547	25,130	3,770	27,000	4,050	27,540	4,131	27,540	4,131
	Property Tax - Sub -Total	**36,488**	**5,473**	**31,990**	**4,799**	**27,150**	**4,072**	**30,314**	**4,547**	**25,130**	**3,770**	**27,000**	**4,050**	**27,540**	**4,131**	**27,540**	**4,131**
Other Deductions																	
6205	Donations -LEAP program		-		-		-		-		-	3,974	596	4,117	618	4,117	618
	Property Tax - Sub -Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**3,974**	**596**	**4,117**	**618**	**4,117**	**618**
	Total O M & A	**1,509,565**	**226,435**	**1,718,034**	**257,705**	**1,793,136**	**268,970**	**1,770,474**	**265,571**	**1,805,717**	**270,857**	**2,080,519**	**312,078**	**2,459,977**	**368,997**	**2,623,797**	**393,570**

	Description	**2006 Actual**	**Allowance for Working**	**2007 Actual**	**Allowance for Working**	**2008 Actual**	**Allowance for Working**	**2009 Actual**	**Allowance for Working**	**2010 Actual**	**Allowance for Working**	**2011 Bridge Year**	**Allowance for Working**	**2012 CGAAP Test Year**	**Allowance for Working**	**2012 IFRS Test Year**	**Allowance for Working**
Rate Used for Working Capital Allowance			0.15		0.15		0.15		0.15		0.15		0.15		0.15		15%
Cost of Power																	
4705	Power Purchased	9,962,641	1,494,396	10,412,871	1,561,931	10,245,258	1,536,789	10,503,206	1,575,481	12,257,256	1,838,588	13,383,430	2,007,515	13,559,196	2,033,879	13,559,196	2,033,879
4708	Charges - Whole Market Sale	894,089	134,113	916,710	137,507	1,040,793	156,119	1,104,948	165,742	1,040,587	156,088	1,227,133	184,070	1,243,399	186,510	1,243,399	186,510
4714	Charges - Network	1,005,460	150,819	1,059,557	158,934	848,610	127,292	878,588	131,788	1,092,905	163,936	1,086,615	162,992	1,237,952	185,693	1,237,952	185,693
4716	Charges - Connection	901,934	135,290	984,885	147,733	863,995	129,599	832,070	124,811	894,021	134,103	884,919	132,738	986,265	147,940	986,265	147,940
4750	Charges - Low Voltage	52,479	7,872	126,358	18,954	125,408	18,811	116,876	17,531	66,400	9,960	130,000	19,500	130,000	19,500	130,000	19,500
	Total Cost of Power	**12,816,602**	**1,922,490**	**13,500,381**	**2,025,057**	**13,124,063**	**1,968,609**	**13,435,689**	**2,015,353**	**15,351,169**	**2,302,675**	**16,712,098**	**2,506,815**	**17,156,811**	**2,573,522**	**17,156,811**	**2,573,522**
	Working Capital Allowance	**14,326,167**	**2,148,925**	**15,218,415**	**2,282,762**	**14,917,198**	**2,237,580**	**15,206,163**	**2,280,924**	**17,156,886**	**2,573,533**	**18,792,616**	**2,818,892**	**19,616,788**	**2,942,518**	**19,780,608**	**2,967,091**

COST OF POWER

Grimsby Power Inc has calculated cost of power for the 2011 Bridge year and 2012 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3. The electricity prices used in the calculation were the published prices in the OEB's Regulated Price Plan Price Report – May 1, 2011 to April 30, 2012, issued April 15, 2011. Grimsby Power Inc. will update the electricity prices should the OEB publish a revised Regulated Price Plan Report prior to a Decision.

The cost of power calculations for the 2011 Bridge Year and a cost of power summary are provided in the following Table 2.30 and Table 2.31 respectively. The cost of power calculations for the 2012 Test Year and a cost of power summary are provided in the following Table 2.32 and Table 2.33 respectively.

Table 2.30 2011 Cost of Power Summary

2011 Load Foreacst	kWh	kW	2010 %RPP
Residential	91,699,965		86.26%
General Service < 50 kW	18,440,477		80.09%
General Service 50 to 4,999 kW	67,681,139	185,444	5.99%
Street Lighting	1,575,556	4,396	0.00%
Unmetered Scattered Load	368,368		99.70%
TOTAL	**179,765,505**	**189,840**	

Electricity - Commodity RPP	Forecasted	2011 Loss	2011		
Class per Load Forecast RPP	**Metered**	**Factor**			
Residential	79,100,161	1.0502	83,070,989	$0.07298	$6,062,521
General Service < 50 kW	14,768,837	1.0502	15,510,233	$0.07298	$1,131,937
General Service 50 to 4,999 kW	4,056,418	1.0502	4,260,050	$0.07298	$310,898
Street Lighting	0	1.0502	0	$0.07298	$0
Unmetered Scattered Load	367,253	1.0502	385,689	$0.07298	$28,148
TOTAL	**98,292,669**		**103,226,961**		**$7,533,504**

Electricity - Commodity Non-RPP	Forecasted	2011 Loss	2011		
Class per Load Forecast	**Metered**	**Factor**			
Residential	12,599,804	1.0502	13,232,314	$0.06837	$904,693
General Service < 50 kW	3,671,640	1.0502	3,855,956	$0.06837	$263,632
General Service 50 to 4,999 kW	63,624,721	1.0502	66,818,682	$0.06837	$4,568,393
Street Lighting	1,575,556	1.0502	1,654,648	$0.06837	$113,128
Unmetered Scattered Load	1,115	1.0502	1,171	$0.06837	$80
TOTAL	**81,472,836**		**85,562,772**		**$5,849,927**

Transmission - Network		Volume	2011		
Class per Load Forecast		**Metric**			
Residential		kWh	96,303,303	$0.0059	$568,189
General Service < 50 kW		kWh	19,366,189	$0.0054	$104,577
General Service 50 to 4,999 kW		kW	185,444	$2.1814	$404,527
Street Lighting		kW	4,396	$1.6452	$7,232
Unmetered Scattered Load		kWh	386,860	$0.0054	$2,089
TOTAL					**$1,086,615**

Transmission - Connection		Volume	2011		
Class per Load Forecast		**Metric**			
Residential		kWh	96,303,303	$0.0049	$471,886
General Service < 50 kW		kWh	19,366,189	$0.0043	$83,275
General Service 50 to 4,999 kW		kW	185,444	$1.7374	$322,190
Street Lighting		kW	4,396	$1.3431	$5,904
Unmetered Scattered Load		kWh	386,860	$0.0043	$1,663
TOTAL					**$884,919**

Wholesale Market Service			2011		
Class per Load Forecast					
Residential		kWh	96,303,303	$0.0052	$500,777
General Service < 50 kW		kWh	19,366,189	$0.0052	$100,704
General Service 50 to 4,999 kW		kWh	71,078,732	$0.0052	$369,609
Street Lighting		kWh	1,654,648	$0.0052	$8,604
Unmetered Scattered Load		kWh	386,860	$0.0052	$2,012
TOTAL			**188,789,733**		**$981,707**

Rural Rate Assistance			2011		
Class per Load Forecast					
Residential		kWh	96,303,303	$0.0013	$125,194
General Service < 50 kW		kWh	19,366,189	$0.0013	$25,176
General Service 50 to 4,999 kW		kWh	71,078,732	$0.0013	$92,402
Street Lighting		kWh	1,654,648	$0.0013	$2,151
Unmetered Scattered Load		kWh	386,860	$0.0013	$503
TOTAL			**188,789,733**		**$245,427**

Table 2.31 2011 Bridge Year Cost of Power Forecast Calculation

	2011
4705-Power Purchased	$13,383,430
4708-Charges-WMS	$981,707
4714-Charges-NW	$1,086,615
4716-Charges-CN	$884,919
4730-Rural Rate Assistance	$245,427
4750-Low Voltage	$130,000
TOTAL	**16,712,098**

Table 2.32 2012 Test Year Cost of Power Forecast Calculation

2012 Load Foreacst	kWh	kW	2010 %RPP
Residential	92,606,843		86%
General Service < 50 kW	18,314,894		80%
General Service 50 to 4,999 kW	68,877,755	188,723	6%
Street Lighting	1,578,145	4,403	0%
Unmetered Scattered Load	355,293		100%
TOTAL	**181,732,931**	**193,126**	

Electricity - Commodity RPP	2012 Forecasted	2012 Loss	2012		
Class per Load Forecast RPP	**Metered**	**Factor**			
Residential	79,882,431	1.0526	84,084,247	$0.07298	$6,136,468
General Service < 50 kW	14,668,259	1.0526	15,439,809	$0.07298	$1,126,797
General Service 50 to 4,999 kW	4,128,136	1.0526	4,345,276	$0.07298	$317,118
Street Lighting	0	1.0526	0	$0.07298	$0
Unmetered Scattered Load	354,218	1.0526	372,850	$0.07298	$27,211
TOTAL	**99,033,044**		**104,242,182**		**$7,607,594**

Electricity - Commodity Non-RPP	2012 Forecasted	2012 Loss	2012		
Class per Load Forecast	**Metered**	**Factor**			
Residential	12,724,411	1.0526	13,393,715	$0.06837	$915,728
General Service < 50 kW	3,646,635	1.0526	3,838,448	$0.06837	$262,435
General Service 50 to 4,999 kW	64,749,619	1.0526	68,155,449	$0.06837	$4,659,788
Street Lighting	1,578,145	1.0526	1,661,156	$0.06837	$113,573
Unmetered Scattered Load	1,076	1.0526	1,132	$0.06837	$77
TOTAL	**82,699,887**		**87,049,901**		**$5,951,602**

Transmission - Network		Volume	2012		
Class per Load Forecast		**Metric**			
Residential		kWh	97,477,963	$0.0066	$647,149
General Service < 50 kW		kWh	19,278,258	$0.0061	$117,141
General Service 50 to 4,999 kW		kW	188,723	$2.4546	$463,239
Street Lighting		kW	4,403	$1.8512	$8,151
Unmetered Scattered Load		kWh	373,982	$0.0061	$2,272
TOTAL					**$1,237,952**

Transmission - Connection		Volume	2012		
Class per Load Forecast		**Metric**			
Residential		kWh	97,477,963	$0.0054	$525,792
General Service < 50 kW		kWh	19,278,258	$0.0047	$91,253
General Service 50 to 4,999 kW		kW	188,723	$1.9125	$360,940
Street Lighting		kW	4,403	$1.4785	$6,510
Unmetered Scattered Load		kWh	373,982	$0.0047	$1,770
TOTAL					**$986,265**

Wholesale Market Service			2012		
Class per Load Forecast					
Residential		kWh	97,477,963	$0.0052	$506,885
General Service < 50 kW		kWh	19,278,258	$0.0052	$100,247
General Service 50 to 4,999 kW		kWh	72,500,725	$0.0052	$377,004
Street Lighting		kWh	1,661,156	$0.0052	$8,638
Unmetered Scattered Load		kWh	373,982	$0.0052	$1,945
TOTAL			**191,292,083**		**$994,719**

Rural Rate Assistance			2012		
Class per Load Forecast					
Residential		kWh	97,477,963	$0.0013	$126,721
General Service < 50 kW		kWh	19,278,258	$0.0013	$25,062
General Service 50 to 4,999 kW		kWh	72,500,725	$0.0013	$94,251
Street Lighting		kWh	1,661,156	$0.0013	$2,160
Unmetered Scattered Load		kWh	373,982	$0.0013	$486
TOTAL			**191,292,083**		**$248,680**

Table 2.33 2012 Test Year Cost of Power Summary

	2012
4705-Power Purchased	$13,559,196
4708-Charges-WMS	$994,719
4714-Charges-NW	$1,237,952
4716-Charges-CN	$986,265
4730-Rural Rate Assistance	$248,680
4750-Low Voltage	$130,000
TOTAL	**17,156,811**

Summary

Grimsby Power Inc. has provided explanations to address its actual capital investments for year 2006 to 2010 and provided details in support of its 2011 Bridge Year and 2012 Test Year capital and working capital requirements as required in the Filing Requirements.

Grimsby Power Inc.'s historical capital investment in its distribution system has primarily been related to its strategy to eliminate distribution stations approaching end of life. This investment has been required to improve the efficiency and reliability of its distribution system to ensure the safe and reliable supply of electricity that Grimsby Power Inc's customers have come to expect.

Grimsby Power Inc. further submits that its forecasted capital investments for the 2011 Bridge Year and 2012 Test Year are consistent with the required investments of prior years and are prudent and just in supporting the continued growth in the Town of Grimsby and the continued safety and reliability of its distribution system.

Appendix 2.1 Grimsby Power Inc.'s Distribution Asset Management Plan (DAMP)

Grimsby Power Incorporated
Distribution Asset Management Plan
2011-2031

Grimsby Power Incorporated
Distribution Asset Management Plan
2011 – 2031
June 2011

GRIMSBY POWER INCORPORATED
Distribution Asset Management Plan
2011 – 2030

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FORWARD

This document is the first attempt by Grimsby Power Incorporated (GPI) to put its asset management strategy into words. GPI and its predecessors have been managing the distribution system assets since electrification occurred in the province of Ontario. Although the concept of asset management is not new, the formal documentation of a plan is new for this utility. The “Distribution Asset Management Plan” (DAMP) provides stakeholders an explanation of the framework within which GPI intends to operate and manage the distribution system assets to meet the required service levels while maintaining a safe and reliable distribution system for its consumers.

GPI is also planning for developmental projects during the life of this plan which may require significant investment. A formal prioritization method has not yet been established for this type of project but the development of a prioritization model will be a key deliverable in the next couple of years as GPI nears completion of its current capital strategy to eliminate all 8kV distribution substations.

This investment in both sustainment and discretionary projects must be approved by the Ontario Energy Board (OEB) through the rate application process.

GPI welcomes feedback from stakeholders on its DAMP and its approach to maintaining a cost effective, safe, and reliable electrical supply to the Town of Grimsby.

Liability Disclaimer

The information and statements made in this DAMP are prepared on the assumptions, projections, and forecasts made by Grimsby Power Incorporated and represents GPI's intentions and opinions at the date of preparation.

Circumstances will change, assumptions and forecasts may prove to be wrong, events may occur that were not predicted, and GPI may, at a later date, decide to take different actions from those it currently intends to take as expressed in this DAMP.

GPI cannot be held liable for any loss, injury, or damage arising directly or indirectly as a result of use or reliance on any information contained within this DAMP.

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1 SUMMARY

1.1 The Purpose of the Plan

The purpose of this Distribution Asset Management Plan (DAMP) is to outline how Grimsby Power Incorporated (GPI) will develop, manage, and maintain its distribution system equipment to provide a safe, reliable, efficient, and cost effective distribution system.

The DAMP identifies the major initiatives and projects to be undertaken over the planning period to meet customer and stakeholder requirements. Preparation of the DAMP in this format is intended to supplement GPI's rate application for 2012 distribution rates to the Ontario Energy Board (OEB).

1.2 Historical Perspective

In 1989 the then Grimsby Hydro Electric Commission adopted an ambitious asset management plan to rebuild the entire distribution system over a 25 year period. At the time a policy was adopted to improve system reliability by converting 4.16kV and 8.32kV distribution systems to 27.6kV. The 4.16kV and 8.32kV was supplied thru a number of distribution substations that were approaching end of life. In addition to the stations the 4.16kV and 8.32kV distribution lines were also approaching end of life. The conversion then had a double benefit – the distribution stations would be eliminated and at the same time the distribution lines would be upgraded or rebuilt giving new life to the distribution system.

The distribution system fed from the oldest stations in an area below the Niagara escarpment was converted first (Phase I). This work took place from 1990 to 2002. The next phase of the plan (Phase II) was to convert the area above the escarpment. This work was planned to take place from 2002 to approximately 2012. In the midst of Phase II capacity issues peaked at the Beamsville TS owned by Hydro One. The solution to this issue resulted in a new Transformer Station being built on the escarpment known as the Niagara West Transformer Station owned by an affiliate company Niagara West Transformer Corporation. Two feeders from the station supply Grimsby Power Inc. and the conversion work set in Phase II of the rebuild plan were focused on loading these two feeders.

1.3 Period Covered

The planning horizon of the DAMP is from 2011 to 2031. It is intended that the DAMP will be reviewed on a periodic basis.

The planning horizon extends for a twenty (20) year period. This period was selected to match Thunder Bay Hydro's benchmark, which was disclosed in an Electrical Distributors Association (EDA) Operations Council Forum on May 9, 2008 – "Asset Management for LDC's - Getting the Plan Right from Conception to Completion". The main focus of the plan concentrates on both 2011 and 2012 as budgets for these years has been developed. A high level plan has been established for 2013 and beyond and analysis tends to be more trend related and based on asset end of life rates as detailed in the Asset Condition Assessment. The Asset Condition Assessment is based on a planning horizon of twenty (20) years and predicts the sustainment of asset through to 2030.

It is very likely that new developments, that are not identified here, will arise at any given time even in the short term of five (5) years.

1.4 Key Assumptions

The development of this DAMP is based on a series of key assumptions that are made as a foundation for planning and forecasting predictions of future activities, whether to maintain, replace or develop new assets (discretionary capital projects).

The key assumptions for this DAMP are as follows:

- Electricity growth rates will continue to be slow in the next five (5) years due to a economy in recovery and the impact of the Conservation and Demand Management (CDM) Programs in lowering demand and electricity usage.
- Recognition that the economy of Town of Grimsby Power depends on a secure and reliable supply of electricity.
- In the next five (5) years regulatory activities by the Ontario Energy Board (OEB) will continue at the current pace putting a heavy strain on GPI's resources. Beyond this timeframe it is hoped that some stability with regulatory requirements will consume less resources.
- The Green Energy Act which received Royal Assent on May 15, 2009 will require significant investment in the distribution infrastructure in order to meet the "Smart Grid" characteristics alluded to in the legislation.
- The installation of smart meters in 2010 will require significant investment to harness the capability of the new metering devices and to promote the "Smart Grid".
- With reference to the "Smart Grid" new technologies will be developed within the planning horizon of this plan. However, at this time the specific nature of how these new technologies would be developed to benefit GPI's customers is not known.
- Present service levels will continue to be maintained and will remain a balance between customer needs, price-quality tradeoffs, and industry best practice(s). Service levels will not be changed significantly due to introduction of new regulatory requirements.
- GPI's DAMP is a strategic document to convey future distribution system development and maintenance plans to stakeholders.
- GPI's asset management systems will continue to be developed in order to process performance information to meet demand, capacity, security, and reliability levels in a timely manner.
- Use of outside line construction firms to perform distribution maintenance, replace, and install assets (as prescribed by work plans of projects) will continue.
- Compliance with relevant regulatory requirements as they pertain to electricity rates, filing requirements, health & safety, and environmental protection will be maintained.
- Meet the requirements of our Shareholder by achieving the objectives set down in GPI's mission statement.

- Asset management planning involves forecasts based on information collected from many sources. Distribution system development for the next two (2) years (2011/12) has been established. The following three (3) years (2013 thru 2014) are less certain and the remaining years of the plan are based solely on trending. As the years pass a regular review of this plan will ensure it is the best it can be.

Review of future achievement (apart from regulatory compliance) will be centred on the following areas:

- Health & Safety Performance
- Financial Performance
- Economic Efficiency Performance
- Reliability Consistency and Improvement
- Environmental Performance

1.5 Asset Management Systems

Asset management systems used by GPI include inspection and maintenance databases, paper records of inspection and maintenance activities, reliability database, asset attribute databases, a graphics information system (GIS – ESRI Platform), and distribution engineering simulation software (DESS Software).

GPI's strategy with respect to asset management is to build the information system for assets around the ESRI GIS platform. Connectivity to other systems such as the Customer Information System (CIS – SAP Platform), and databases enhance the sophistication of the entire asset management product. The first GIS platform (CableCad) was initiated in 1996 and is fully functional with land base representation, circuit representation, asset location, and connectivity to asset records. In 2009 GPI migrated to the ESRI platform for their GIS. The DESS software was purchased in 2007 and is fully operational. GPI does not have a SCADA system.

1.6 Distribution System & Asset Description

The GPI distribution system supplies approximately 10250 customers throughout the Town of Grimsby. These customers are supplied by one (1) Hydro One owned transformer station and by one (1) Niagara West Transformation Corporation owned transformer station (TS's) which deliver 19.77GWh of billed energy at a maximum demand of 42.51MW. (Figures from 2010).

The service area of GPI covers 69 square kilometers, and includes all geography within the borders of The Town of Grimsby, in the Regional Municipality of Niagara. Of the 69 square kilometers – 19 square kilometers is urban and 50 are rural.

A breakdown of the assets in terms of their original cost is shown in Appendix A and a map of the service territory shown in Appendix B.

1.7 Service Levels

GPI abides by the OEB prescribed levels of service and reliability standards dictated by the following:

- Chapter 15 of the 2006 Electricity Distribution Rate Handbook – Service Quality Regulation and,
- Amendments to the Distribution System Code - Board File No. EB-2008-0001.

There has been a customer survey performed by Utility Pulse in 2006 to ascertain what GPI customer's felt about the service it provides and if reliability expectations are being met. Ninety (90%) of the customers agreed 'strongly' + 'somewhat' that GPI provides consistent, reliable energy.

1.8 Network Development Plans

Asset enhancement and development projects have been identified and details are outlined in the capital budgets for 2011 and 2012. Trended capital budgets have been prepared for years 2013 thru 2014.

1.9 Life Cycle Asset Management

Information about GPI's asset attributes and condition data are held within databases, various paper records and files. Asset conditions are assessed by various inspection and maintenance activities. These activities are analyzed to determine what appropriate maintenance intervals best suit the asset. Detailed attribute condition information is presently being collected and with time the confidence level of this information will improve.

A comprehensive Distribution System Maintenance and Inspection Program (attached as Appendix C) has been developed to guide GPI's decisions with respect to maintenance & inspection intervals.

Operational and maintenance expenditures are outlined in the O&M budgets for 2011 and 2012.

1.10 Risk Management

GPI's Distribution System Maintenance and Inspection Program document is aimed in part to protect the public from physical, electrical, and environmental hazards by maintaining a schedule of regular asset inspections or maintenance activities.

Ontario Regulation 22/04 - Electrical Distribution Safety is a key regulation which requires GPI and all other LDCs to maintain distribution standards, material standards, and construction verification programs to safeguard the public from hazards associated with the distribution system. The Electrical Safety Authority (ESA) is responsible for enforcing the regulation and this is done through a system of annual audits and regular field inspections.

GPI promotes excellence in health and safety management in order to prevent losses to people, assets, environment, and reputation. Keys to this H&S Management system are the evaluation of risk for all workplace hazards, regular H&S meetings with staff, and feedback on losses or near losses occurring in the workplace.

Written emergency response procedures have been prepared as follows:

- Distribution System Emergency Contingency Plan
- Sabotage Reporting

GPI will follow all regulatory requirements and guidelines to ensure the distribution system has a low risk impact on the environment.

1.11 Evaluation of Performance

Formal performance benchmarks have not been established at GPI. However, a number of initiatives have been undertaken to develop data systems from which performance measures can be developed. As initiatives are implemented more data is available for analysis which will lead to better information. Once a better stream of information is available specific performance indicators can be created. GPI's philosophy is one of continuous improvement and the evaluation of performance is one area where more development activity is required.

2 Background and Objectives

2.1 Purpose of this DAMP

The purpose of the DAMP is to provide a management framework to ensure that GPI:

- Maintains service levels that will meet customer, community, and regulatory expectations for its distribution system network.
- Understands what levels of distribution system capacity, reliability, and security of supply will be required both now and in the future, and what issues will drive these requirements.
- Have programs and procedures to manage all phases of the distribution system life cycle from inception to retirement.
- Has considered the management of the distribution system in terms of the best risk management practices with the ultimate goal of minimizing identified risks.
- Has made adequate provisions to fund all phases of the distribution system asset life cycle.
- Makes decisions based on structured business strategies and models.
- Has a continuously improving knowledge of its assets with respect to locations, age, condition, capacity, and attributes.

This DAMP is not intended to be a detailed description of GPI's distribution system assets, but it is intended to be a description of the thinking, the policies, the strategies, the plans, and the resources that GPI uses to manage the assets.

2.2 Planning and Operating Contexts

All of GPI's distribution system assets exist within a strategic context that is shaped by a wide range of issues including GPI's Vision and Mission, this DAMP, regulatory environment, government policy objectives, commercial pressures, and technology trends. GPI's distribution assets are also influenced by technical regulations (i.e. – construction and clearance standards), asset deterioration, and various risk exposures independently of the strategic context.

2.2.1 Strategic Context

GPI's strategic context includes many issues that range from the local and Canadian economy to developing technologies. Issues which are considered to impact this DAMP include:

- The prevailing regulatory environment which constrains electricity rates and rates of return, requires stable or improving reliability indices, and requires complex reporting of financial and operating performance.
- Government policy objectives such as the implementation of conservation and demand management programs, smart meters and the introduction of the Green Energy Act.
- GPI's commercial goals.
- Local, national, and global economic cycles.
- Interest rates and the general business confidence in Town of Grimsby which influences the rates at which new customers connect to lines.
- Ensuring sufficient funds and skilled people are available in the short, medium, and long term to resource GPI's service requirements.

2.2.2 Independence from Strategic Context

While GPI's assets and asset configuration will be shaped by the strategic issues identified above in "Strategic Context" that are relevant to its stakeholders, it is also important to recognize that the assets will also be influenced (and sometimes constrained) by issues that are independent of the strategic context. For example the rate at which wooden poles rot is independent of the scarcity of skilled contractors. This issue may constrain the rate at which GPI replaces rotten poles, but it does not influence the rate of rot.

Samples of issues that are independent of GPI's strategic context include:

- Technical regulations including Regulation 22/04 – Electrical Safety and the new Regulations on Farm Stray Voltage.
- Asset configuration, condition, and deterioration – these parameters will significantly limit the rate at which GPI can invest in upgrades or enhancements to the distribution system.
- The physical characteristics of electricity systems which govern such fundamental issues as voltage regulation, capacity, power flows, and faults.
- Physical risk exposures – exposure to such events as wind, lightning, snow/ice, motor vehicle impacts, theft of copper, and unwanted human interference are independent of strategic context.
- Health and safety requirements such as line clearances and grounding of equipment.

2.3 Key Planning Documents

2.3.1 Vision and Mission Statements

GPI's vision and mission statements are as follows:

GPI's vision is:

- be adaptable;
- continue to provide economical efficient energy;
- be in business for our customers;
- be a locally owned business;
- strive to be efficient in any new operation to meet our customers' needs, and;
- partner with others to drive economies of scale and scope.

GPI's mission is:

- Grimsby Power Incorporated is committed to provide the customers of Grimsby with a safe and reliable electricity supply while operating effectively and efficiently at an equitable cost.
- Grimsby Power Incorporated will grow the business and increase shareholder value.

2.3.2 Strategic Plan

This DAMP is the main tool used to set the action plan for creating capital and operations/maintenance budgets over the planning horizon.

2.3.3 Asset Strategy

The asset strategy, which until now, has not been formally documented as an asset management plan, has been utilized to varying degrees since the inception of the distribution system in Ontario. The guiding principles for today's distribution system asset strategy are:

- Maintain awareness of safety around electricity at the forefront for company, customers, and the general public.
- Exploit the availability of lines constructed for 27.6kV to improve reliability and electrical losses.
- As maintenance and construction occurs upgrade hardware on all distribution equipment to facilitate a seamless transition to the 27.6kV feeder voltage.
- Design the distribution system with the intent of maximizing the reduction in electrical losses.
- Improve customer reliability through effective maintenance plans and planned replacement of assets at their end of life.
- Maintain power quality by implementing the modeling of the electrical distribution system in GIS and distribution engineering simulation software (DESS).

- Assist the connection of renewable embedded generation by identifying the constraints and providing solutions which enable proponents to connect to the distribution system.

The implications of these guiding principles are rooted in GPI's sustainment and discretionary projects.

2.3.4 Prevailing Regulatory Environment

The Electricity Distribution Industry in Ontario is regulated under the Ontario Energy Board Act, 1998, the Electricity Act, 1998, and the Electricity Restructuring Act, 2004 all of which are administered by the Ontario Energy Board (OEB).

The Ontario Energy Board Act, 1998 sets out the following guiding objectives for the OEB with respect to electricity:

- To protect the interests of consumers with respect to prices and the adequacy, reliability, and quality of electricity service.
- To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

These regulatory requirements dictate or heavily influence GPI's rates, fees, and return on equity. Rates are required by legislation to be approved annually by the mechanisms specified by the OEB.

2.3.5 Government Policy Objectives

In May 2009 the Ontario Legislature passed Bill 150, the Green Energy and Green Economy Act, 2009. This legislation is a framework legislation aimed at making fundamental changes to the roles and responsibilities of local distribution companies (LDC's). This act will lead to a number of supporting regulations required to implement the Act. The implications of the act will likely result in significant asset expenditures by LDC's to support embedded generation and the ideals of a "smart grid". However, at this time it is too early to determine what impact this legislation will have on capital investments and subsequent rates to support these expenditures.

2.3.6 Annual Business Planning

GPI produces, has produced by third parties, or updates a number of key documents which support the annual business planning process. These documents include the distribution system maintenance and inspection program, asset condition assessment, and detailed budgets. Going forward, this distribution asset management plan will also be reviewed.

2.3.7 Annual Budgets

Each year GPI produces an annual budget for the year ahead which reflects the costs of individual projects and expenditures over the year. This budget is created by reviewing asset and operational issues experienced in the past and anticipated for the future. This budget contributes to the long term alignment with the strategic context. It must be understood that this alignment process is very much a moving target.

For the last two years and in support for GPI's rate application in 2011, GPI has produced budgets going forward two years. In addition to the detailed annual budget a three year forecast (2012 plus two years) details trended costs over this period.

A critical activity for GPI (moving forward) is to ensure that the annual budget reflects the fundamentals of this DAMP.

2.4 Period Covered by this DAMP

This DAMP covers a period from January 1, 2011 to December 31, 2031.

There is an obvious degree of uncertainty in any predictions of the future and as such the DAMP contains a level of uncertainty. The influence of government regulation, ongoing adjustments to LDC regulation by the OEB, customer growth, and the general state of the economy makes for a substantial degree of uncertainty.

Accordingly GPI has established the following certainties to the timeframes of the DAMP:

Timeframe	Residential	Commercial/Industrial	Embedded Generation
Year 1	Certain	Little if any certainty	Some certainty
Year 2	Certain	Little if any certainty	Some certainty
Year 3 to 20	Some Certainty	Little if any certainty	Little if any certainty

2.5 Managing Stakeholder Interests

2.5.1 Identifying Stakeholders

GPI is governed by a Board of Directors and has two shareholders The Town of Grimsby and Fortis Ontario. Other stakeholders include:

- Electricity retailers, customers, and end consumers
- Contractors and service providers
- Distribution Supplier - Hydro One & Niagara West Transformation Corporation
- Tree owners
- Government agencies such as the OEB, OPA, & IESO
- Land owners where GPI lines run

GPI has contact with all of its stakeholders. Their suggestions provide opportunities for GPI to conduct its business and provide perspective about rates and service levels.

2.5.2 Accommodating Stakeholder Interests

Stakeholder interests can be viewed from a number of perspectives including financial stability, electricity rates, and quality of supply, safety, and compliance. Financial stability is required to ensure that shareholders and lending institutions have sufficient confidence to continue owning and investing in GPI. Electricity rates provide the means for GPI to create revenue and signal underlying costs. Not charging appropriate rates has economic implications for both GPI and its customers. Quality of Supply includes emphasis on reliability with respect to the number of interruptions, the duration of interruptions, the amount of flicker, and the quality of voltage. Safety involves staff, contractors, customers, and the general public. GPI must ensure the operation of the distribution system is safe for all. Compliance with respect to financial, safety, and environmental matters need to be complied with.

GPI accommodates stakeholder interests as follows:

Interest	How GPI accommodates stakeholder interests
Financial Stability	GPI will accommodate stakeholders' needs for long term viability by returning a dividend to the shareholders.
Electricity Rates	GPI's revenue is constrained by regulatory requirements, conservation and demand management activities, and the state of the economy. Failure to collect enough revenue to fund reliable assets will impact customers in a negative way. Conversely collecting too much revenue penalizes customers and transfers a disproportionate proportion of wealth to the shareholder. GPI's pricing strategy must be cost effective and at the same time be enough to continue to balance distribution system security, capacity, reliability, and return on investment.
Quality of Supply	A customer survey was performed in 2006 and customers indicated that they expect their utility to provide consistent, reliable energy, handle outages and restore power quickly and make using electricity safely an important priority. For this reason GPI will continue to effectively rebuild its infrastructure with funds available.
Safety	GPI will ensure that the public is kept safe by ensuring all assets are structurally sound, live conductors have maintained at least minimum clearances, enclosures are kept locked, and touch & step potentials are kept to a minimum. GPI will ensure the safety of its staff by implementing and continuously improving its safety management program.
Compliance	GPI will disclose performance information as required by regulators and ensure that safety issues are thoroughly documented.

2.5.3 Managing Conflicting Interests

Conflicting interests will be managed as follows:

- Safety must be 1st Priority - Safety of staff, contractors, and the public will always be the highest priority even if this means exceeding budgets or risking non-compliance.

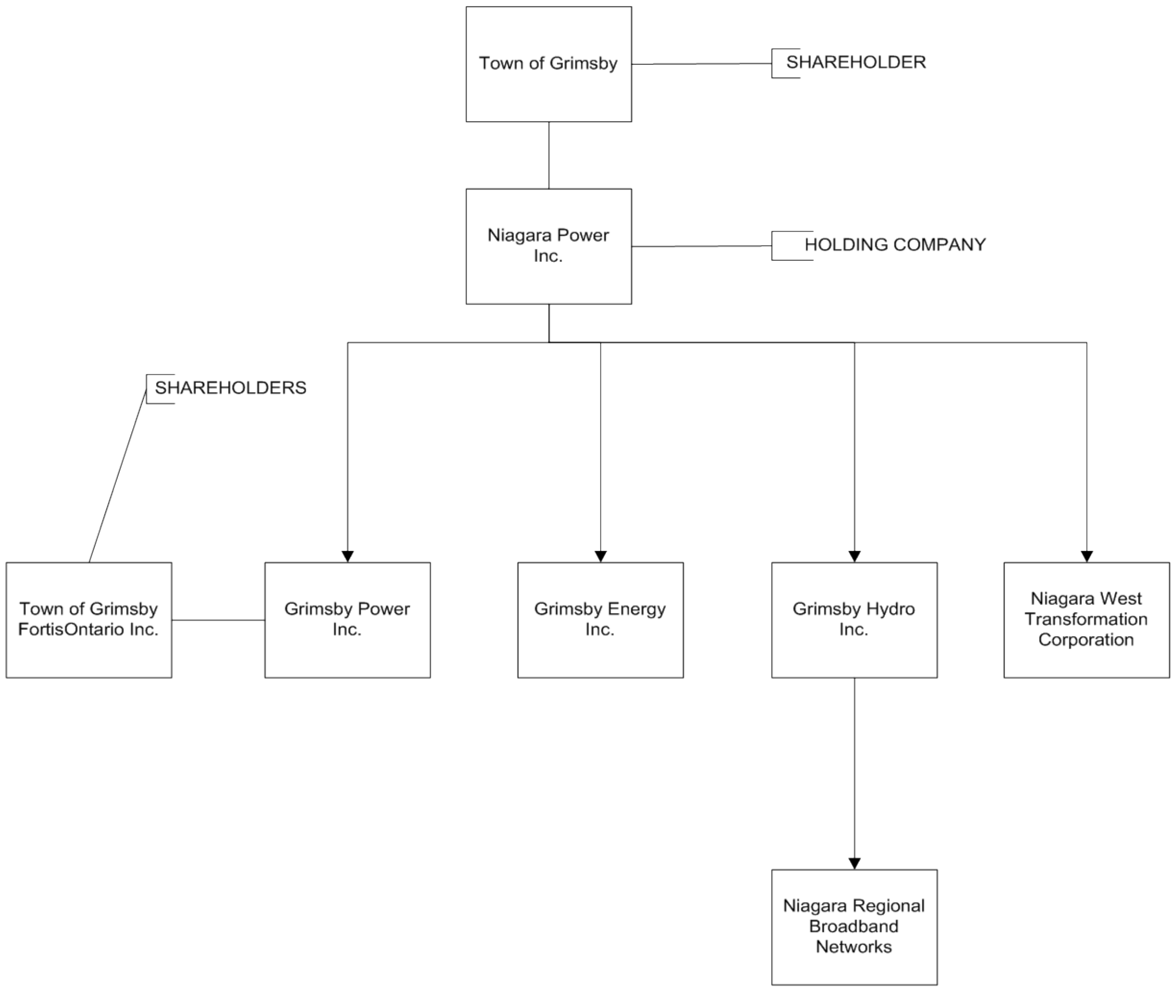
- All other interests must be managed as the situation dictates and will out of necessity be a balance of some proportion (not necessarily equal proportions) between the interests:

- Financial Stability – GPI must be financially viable or it will not exist to manage other conflicts.
- Quality of Supply – Customers want value and are willing to pay for a certain level of quality.
- Electricity Rates – Rates reflect an appropriate balance between revenues and expenditures.
- Compliance – Other than safety.

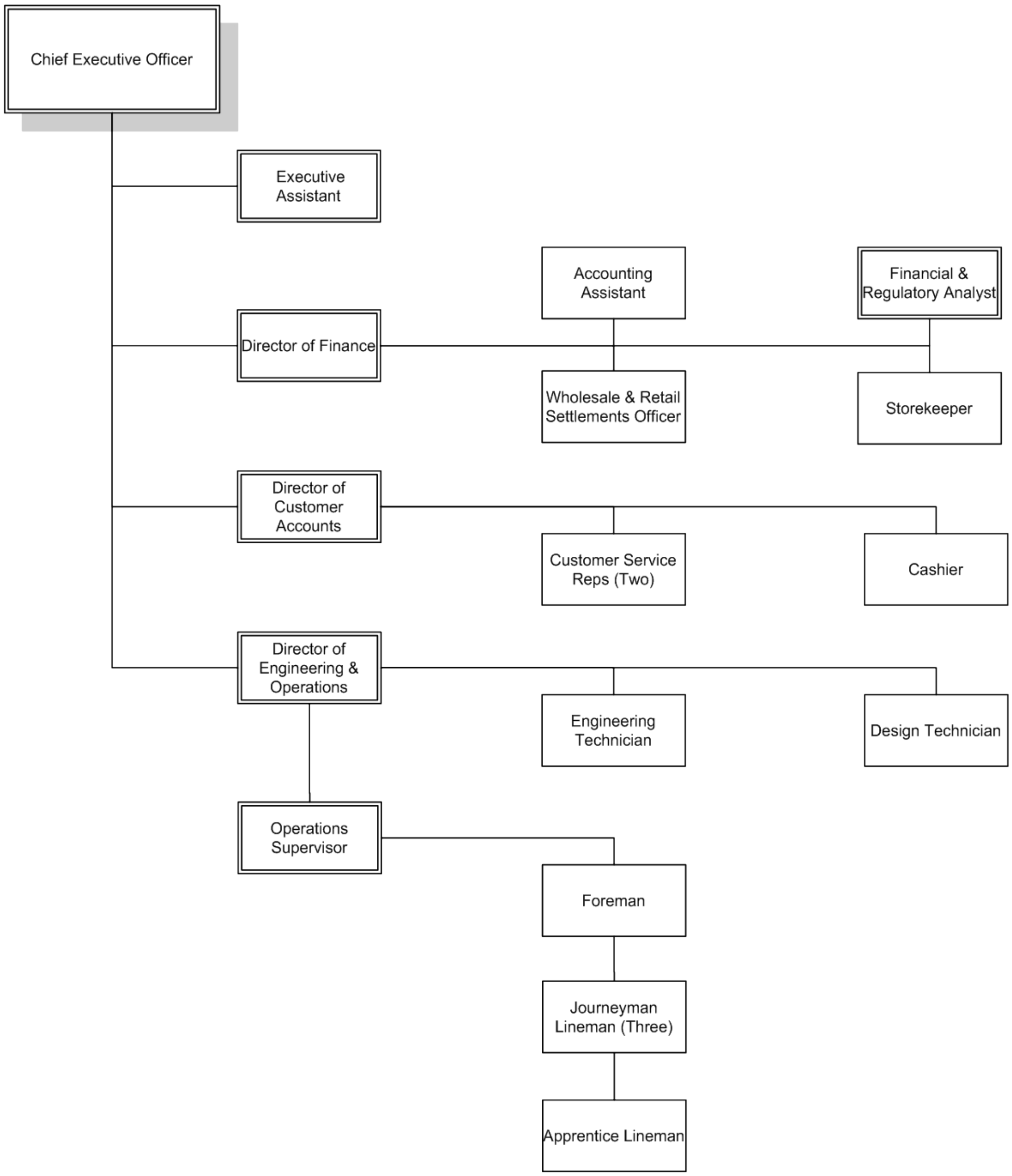
2.6 Accountabilities for Asset Management

GPI's accountabilities for asset management are reflected in the following figures describing the corporate entities and corporate organizational structure with area of responsibility.

Grimsby Power Inc. – Corporate Entities Relationship Chart



Grimsby Power Inc. – Organizational Structure



2.6.1 Accountability at Shareholder – Owner Level

GPI is a subsidiary of Niagara Power Inc (NPI) and GPI has two shareholders - The Town of Grimsby and Fortis Ontario Inc.

2.6.2 Accountability at Governance Level

GPI is governed by a Board of Directors and the Directors are appointed by NPI with approval from the Shareholders. NPI also has a Board of Directors which is appointed by the Town of Grimsby. GPI has six directors, two of which are independent from any affiliate.

2.6.3 Accountability at the Executive and Management Level

The Chief Executive Officer (CEO) is accountable to the Board of Directors and the Management Level is accountable to the CEO through business goals, the development and execution of annual budgets, and various standards & processes that apply to the distribution system assets.

Accountability for financial and regulatory activities lies with the Director of Finance. This role provides all financial reporting, assets funding provisions, and budgeting process for all phases of the DAMP.

Accountability for managing the lifecycle of existing assets, the installation of new developments, and the installation of new assets lies with the Director of Engineering & Operations. This role addresses long term planning issues such as capacity and security.

Accountability for the daily continuity and restoration of electrical supply lies with the Operations Supervisor. This role provides control and dispatch for electrical restoration.

2.6.4 Key Reporting Lines

The Board of Directors governs GPI's electrical distribution business and manages this overall responsibility through the CEO.

The GPI Board of Directors meets quarterly and receives quarterly reporting from management outlining financial, operational, and safety performance as well as the progress in maintenance, operational, and capital programs.

2.6.5 GPI Operating Structure

2.6.5.1 Location

GPI's operation is based in one centralized location at 231 Roberts road, Grimsby. All staff report daily to this location.

2.6.5.2 Engineering & Operations Group

The Engineering & Operations Department provides a seamless design to build process which includes:

- Planning and design for new capital works including all new connections to the distribution system;
- Analysis of system configuration with such inputs as growth, new connections, voltage levels, and capacity information with a view to optimize the configuration of the distribution system;
- Operating, emergency response, connection services, maintenance services, and capital construction services;
- In conjunction with contractors collects information required by the "Distribution System Maintenance & Inspection Program" in the management of existing assets;
- Executes the design plans;
- Produces material requirements to be utilized and warehoused.

2.6.5.3 Finance Group

The Finance Department provides financial reporting & analysis, budget support, accounting, rate design, and regulatory support to meet regulatory requirements.

3 Asset Management Systems

3.1 Asset Knowledge

Asset information is essential to a properly functioning asset management plan. GPI has various records, both paper and electronic, which identify asset attributes and condition data. The following table summarizes the status of the collection of asset attributes with respect to each asset category (based on May 2011 information).

Description of Asset	% Of Asset Attributes Known	% of Condition Data Collected
Distribution Station Transformers	100	100
Pole Mounted Transformers	93.3	100
Pad Mounted Transformers	99.2	100
Poles	97.9	100
Gang Operated Overhead Switches	100	5
Pad Mounted Switchgear	100	75
Underground XLPE Cable	91	N/A

The method of information collection and storage is a key component to successfully managing the data from all assets. Records are kept in a number of formats either paper based files, database (MS Access-Db), or spreadsheet (MS Excel-Sp) based.

3.2 Improving and Using Asset Knowledge

GPI's strategy is to make the GIS platform the keystone of all asset information. Currently asset data, for poles and distribution transformers, such as global coordinates, asset number (unique ID #) and physical attributes are available or accessible directly from the map. Condition data is being collected (electronically) for poles, transformers and switchgear and downloaded into discrete databases. In the future GPI is confident that existing systems will be continuously improved so that all information (asset attribute and condition data) for all assets will be housed under the GIS format. This is essential in order to prepare meaningful asset condition assessments on a regular basis upon which replacement and development activities decisions can be made.

3.3 Key Systems and Processes

GPI's key tool to manage asset knowledge is its ESRI Graphical Information System (GIS). This system in conjunction with a number of connected databases and spreadsheets residing on the outside of the main software platform contains the attributes and maintenance/inspection information for some of the distribution assets as noted in the above table. A graphical representation of the specific asset is placed on top of an aerial photo of the ground within the service territory of GPI. This graphical representation presents a software link to the asset attributes collected in the system. In addition to the GIS, a number of paper records also exist which contain the asset information.

4 Summary of Assets Covered

4.1 Distribution Area

GPI's distribution system covers approximately 69 square kilometers bounded within the confines of The Town of Grimsby, in the Regional Municipality of Niagara. This area includes approximately 19 square kilometers of urban service territory and 50 square kilometers of rural service territory. The Town of Grimsby is home to 26,042 residents. A map of the service territory is shown in Appendix B.

Generally speaking the urban service territory is comprised of mostly residential development with a supporting small commercial area. The rural area is comprised mainly of agricultural industry.

4.1.1 Demographics

4.1.1.1 Key Economic Activities

The Town of Grimsby is home to small businesses which includes a thriving agricultural sector and a developing tourism industry.

4.1.1.2 Energy & Demand Characteristics

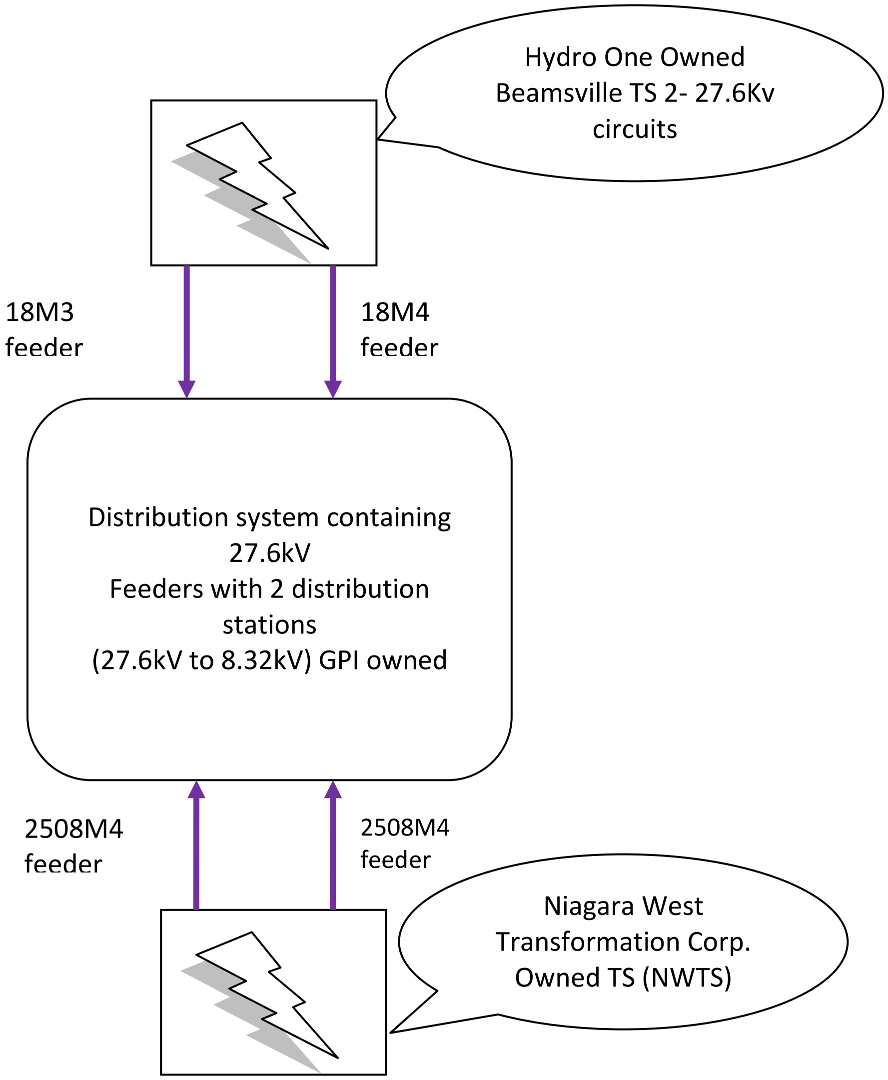
Key energy and demand figures separated into transformer station areas and based on historical information from 2004 to 2010 are as follows:

Transformer Station	Maximum Monthly Energy Usage	Maximum Monthly Demand	Long Term Trend GWh	Long Term Trend MW
Beamsville TS	7.14GWh	13.66MW	Flat Growth	Flat Growth
Niagara West TS	12.63GWh	28.85MW	Flat Growth	Flat Growth

4.2 Network Configuration

GPI is connected to the Ontario power transmission grid at two (2) transformer stations which one (1) is owned by Hydro One (HO) and one (1) is owned by Niagara West Transformation Corporation. GPI customers are supplied via four (4) 27.6kV feeder circuits which emanate out of these transformer stations (two (2) per Station). Within the service territory of GPI there are also two (2) GPI owned distribution stations fed from the 27.6kV circuits which supply GPI customers with two (2) 8.32 kV circuits which emanate one (1) circuit per station. Responsibility for maintaining circuits lies with the respective owners of the equipment.

The basic configuration is shown below:



4.3 Assets by Category

GPI has the following major assets:

Description of Asset	# of Assets
Distribution Station Transformers	2
Pole Mounted Transformers	871
Single Phase Pad Mounted Transformers	503
Three Phase Pad Mounted Transformers	104

Poles	3841
Gang Operated Overhead Switches	62
Pad Mounted Switchgear	10
Underground XLPE Cable	87.8 km

The above data is current as of December 2010.

5 Managing the Existing Assets

Electricity assets like any other type of physical asset have a lifecycle. This section describes how GPI assets are managed over their entire lifecycle from conception to retirement.

5.1 Maintenance Planning

GPI manages assets with the intent of providing a safe, efficient, reliable, and cost effective electricity distribution system.

For example distribution transformers are manufactured with the intent that there is no need to provide regular maintenance (maintenance free) for the duration of their lifecycle. Generally speaking they remain in service providing continuous service until they reach the end of their lifecycle – they fail in service.

Some distribution assets remain in service delivering electricity with little required maintenance. However, a small percentage of the distribution assets such as substation transformers do require regular maintenance. These transformers generally supply many hundreds or thousands of customers and a failure would likely result in a lengthy outage and a significant number of resources to replace a failed unit. This maintenance involves regular condition testing which highlights or identifies possible problems.

The inspection and maintenance of distribution assets is detailed in GPI's "Distribution System Maintenance and Inspection Program" attached as Appendix C. The maintenance and inspection program was first introduced in 2006 and is very much a work in progress. Prior to this time there was no documented program in place and records of maintenance or inspection activities were either poorly organized or non-existent. The document is continuously being updated with new information upon which maintenance or inspections of equipment are based. Maintenance standards in the program are built upon manufacturer's recommendations, industry regulatory requirements, industry best practices, and GPI's own experience with performing the maintenance or inspection. The document clearly describes the geographic area and frequency of programs, the specifications or standards for the work, who is responsible to carry out specific actions, the accounting job numbers associated with the work, and the forms necessary to document the field work.

The strategy behind this program was based on the fact that for the most part minimal maintenance had been performed or documented for the majority of distribution assets. The initial intent of the program is to provide base knowledge to provide enough information to make informed decisions on future maintenance. Initial intervals for maintenance may be changed based on actual experience with field data collected. For example, most of the maintenance forms have the following questions that are required to be filled out by the maintainer:

Indicate which one of the following statements applies to this particular switch:

☐ A The maintenance was unnecessary; it could have been done later
☐ B The maintenance was performed at the right time; only normal maintenance was req'd
☐ C The maintenance should have been done earlier; major faults were found

This process will allow GPI to collect information and base future intervals on the actual existing condition of the asset. In this way the cost to perform maintenance can be optimized. The data collected from the maintenance provides valuable information upon which to base repair work, refurbishment activities, and asset replacement schedules.

In addition to actual asset maintenance a number of programs exist to enhance the reliability of the assets or to identify problems with assets. These programs are as follows:

- Ultrasound detection – An ultrasound detection patrol was conducted of our area in 2005 to detect any arcing issues on our overhead distribution system. Concerns detected were visually inspection by the line crew verify and conclude that a problem actually existed. Ultrasound detection is conducted on all pad mounted transformers once every three (3) years in urban areas and once every six (6) years in rural areas. Critical items identified are corrected immediately and non-critical items are scheduled for repair in conjunction with other planned work.
-
- Line Clearing and Tree Trimming – Tree contacts are a major cause of distribution system outages and momentary interruptions for GPI customers. GPI has a regular line clearing and tree trimming maintenance program. This program cycles through the service territory on a five year basis. In 2011 the program was changed to an area by area program. Currently the schedule is to complete each area at least once in a five year period subject to change based on conditions found.

5.2 Understanding Asset Lifecycles

Definition of Key Lifecycle Activities:

Activity	Detailed Definition
Operations	Involves changing the design parameters of an asset such as changes in circuit configuration or setting a tap setting on a transformer. Does not involve a physical change to the asset. Line clearing of trees is an operations activity.
Maintenance	Involves replacing consumable components on asset assemblies but not the whole assembly. Generally these sub components wear out

	before the whole assembly fails. For example an insulator on a pole assembly or an arc snuffer/muffler on a gang operated load break switch.
Sustainment	Involves replacing assets in terms of the assets listed under asset categories. For example replacing a pole in a pole line.
Retirement	Removes an asset from the distribution system. For example removing a redundant pole line from service. By definition retirement would be a reduction in the distribution system footprint.

5.3 Operating the Assets

Operational activities generally arise in dealing with distribution system issues when assets are not operating as normal. For example a number of triggers exist as follows:

- Voltage levels too high or too low – outside of Canadian Standards Association Voltage Variation Limits for circuits up to 1000V under “Normal Operating and Extreme Operating Conditions”
- Fault current exceeds thresholds on protective devices such as reclosers, fuses, and breakers
- Demand exceeds thresholds on protective devices and or the assets current carrying capacity
- Customer concerns about the quality or reliability of electricity being supplied to them

5.4 Maintaining the Assets

As stated above maintenance is primarily about replacing consumable components of assets. Components wear out in a number of ways including oxidation, pitting or erosion of contact surfaces, material rot, gasket degradation, pitting of insulators, etc. Continued operations of devices which clearly exhibit component degradation will eventually lead to a failure in the distribution system. What leads to failure is a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycles, stress due to fault events, ambient temperature, contaminants, and the maintenance performed during the life of the asset.

Specific maintenance strategies such as run to failure or decisions to clean pad-mounted switchgear have been developed primarily based on past maintenance histories or the lack thereof and the information contained in the Asset Condition Assessment.

6 Service Levels

This section describes how GPI considers its service levels and relates them to the distribution assets.

GPI assesses what customers preferences are by obtaining informal feedback from customers during regular daily interactions with the utility. GPI considers service levels to include a broad range of services including capacity, quality of electrical supply,

continuity, restoration, ground clearances to conductors, grounding of equipment (public safety), and the absence of (radiant) interference.
GPI considers customer preferences to fall into three categories in order of priority as follows:

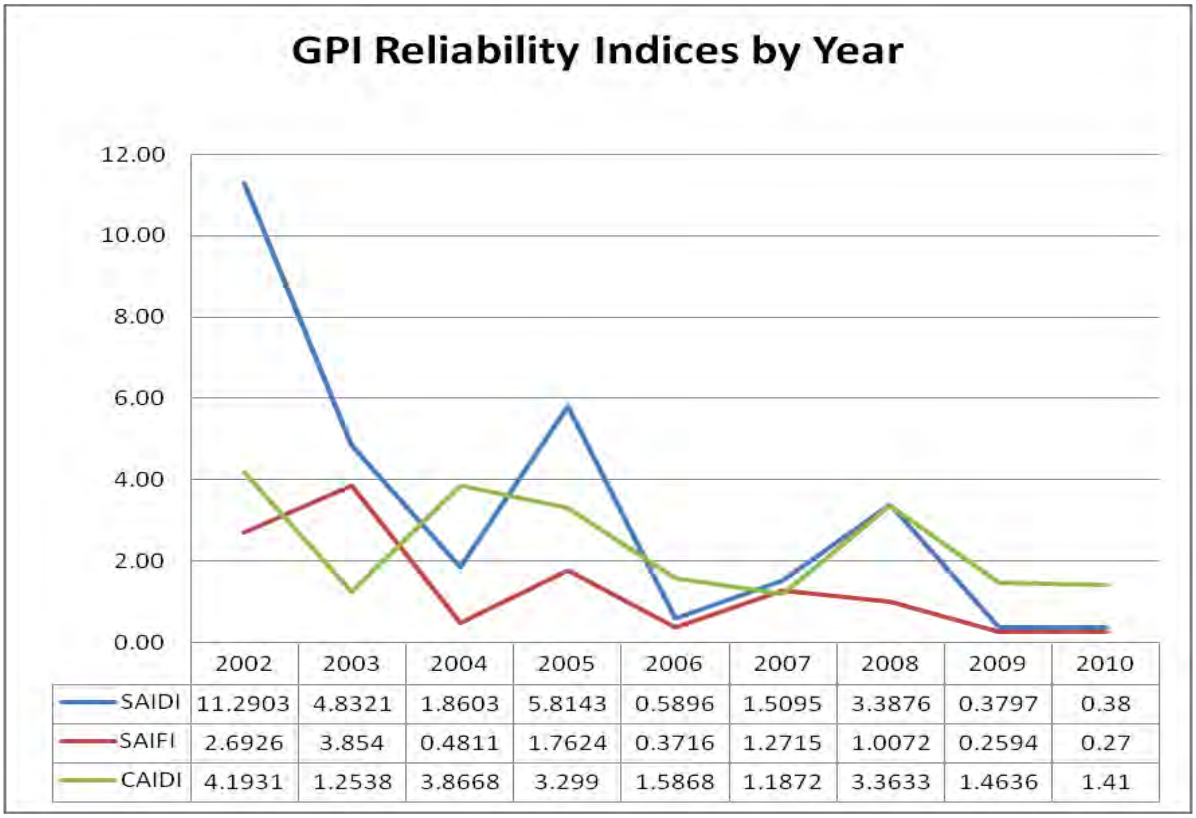
- Reliability – continuity and reliability of electrical supply
- Quality – the absence of momentary interruptions and non-standard voltage levels
- Process – answering the phone, processing regular utility transactions such as new service connections & upgrades to electrical services, and outage notices

6.1 Service Levels - Reliability

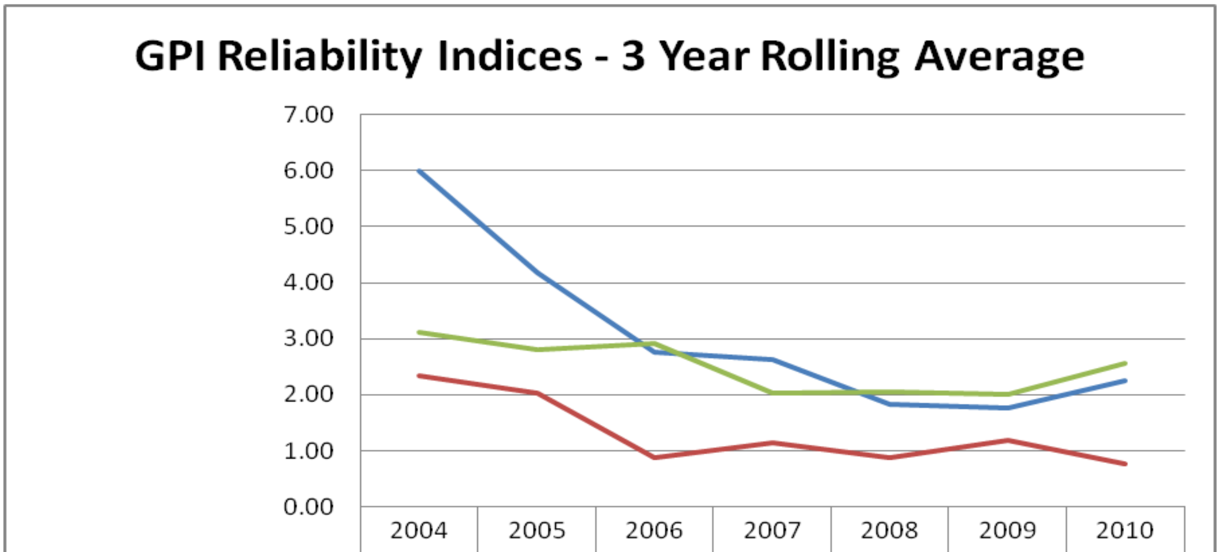
The reliability of supply is primarily measured by three internationally accepted indices called SAIDI, SAIFI, and CAIDI. They are defined as follows:

- SAIDI – System Average Interruption Duration Index – the length of outage customers experience in the year on average – expressed as hours per customer per year;
- SAIFI – System Average Interruption Frequency Index – the average number of interruptions each customer experiences – expressed as # interruptions per year per customer;
- CAIDI – Customer Average Interruption Duration Index – the speed at which power is restored – expressed as average duration in hours per customer per year.

GPI's indices history is shown in the table below (includes loss of supply):



	2002	2003	2004	2005	2006	2007	2008	2009	2010
SAIDI	11.2903	4.8321	1.8603	5.8143	0.5896	1.5095	3.3876	0.3797	0.38
SAIFI	2.6926	3.854	0.4811	1.7624	0.3716	1.2715	1.0072	0.2594	0.27
CAIDI	4.1931	1.2538	3.8668	3.299	1.5868	1.1872	3.3633	1.4636	1.41



	2004	2005	2006	2007	2008	2009	2010
SAIDI (3 year Rolling Average)	5.994	4.169	2.755	2.638	1.829	1.759	2.256
SAIFI (3 Year Rolling Average)	2.343	2.033	0.872	1.135	0.883	1.179	0.776
CAIDI (3 Year Rolling Average)	3.105	2.807	2.918	2.024	2.046	2.005	2.552

As shown by the graphs the trend in the indices numbers has decreased since 2004. This decrease is believed to be significantly influenced by the construction of a new Municipal Transformer Station (Niagara West Transformer Station (NWTS)), which provided two (2) additional circuit feeders to our distribution system in March 2004. And the ongoing of new construction of distribution circuits to convert the existing 8.32kV circuits to the new standard of 27.6kV level connected to the two (2) new feeders at NWTS.

The reliability of supply is affected by GPI's sustainability programs (for existing assets), discretionary capital projects, operating processes, and factors which are not under the control of GPI such as weather disturbances and motor vehicle accidents.

6.2 Causes of Outages

Since the beginning of 2002 GPI has been tracking the causes of outages. The information source for these particular statistics is the same database that is utilized in calculating the reliability indices in Section 6.1 above. The Outages by Cause for 2002 to 2010 are shown in two graphs as attached in Appendix D. Both sets of graphs reflect outages in terms of the number of incidents that occurred each year by specific causes. It is GPI's intent to utilize this information as an input into the prioritization of both maintenance and capital expenditures.

6.3 Service Levels - Quality

Issues with quality of supply usually results in customer complaints. Measuring the response and actions to customer calls about poor quality is an indicator of the service level being provided. In an overhead system the control of momentary interruptions is a difficult one to reduce with any certainty because adverse weather along with tree and animal contacts affect this factor considerably. However, regular tree trimming, the installation of animal guards on all distribution transformer primary bushings, and the constant vigilance of eliminating system defects through inspection and maintenance is believed to have a significant impact. Low voltage is usually related to either a defective asset or a capacity issue.

6.4 Service Levels - Process

Process issues are generally the customer's perception of how GPI goes about its business. The primary measure for this is the reception of customer complaints. In some cases these are relatively easy to address with process management improvement practices but, they may also be relatively expensive to implement. An example of this is the purchase of a new phone system to generate a better interface with the customer. Some service levels are required by OEB regulation and this allows GPI to maintain a consistent level of service in these areas. Specifically the following services are measured:

- Connection of New Services
- Appointment Scheduling
- Appointments Met
- Rescheduling a Missed Appointment
- Telephone Accessibility
- Telephone Call Abandon Rate
- Written Responses to Enquiries
- Emergency Response

- The above service levels are reported to the OEB as required annually.

6.5 Public Safety

- Public safety in Ontario with respect to the electrical distribution system operated by GPI is governed by Ontario Regulation 22/04 – Electrical Distribution Safety.

7 Sustaining Existing Assets

7.1 Assets by Category

GPI's distribution assets are grouped as follows:

- Distribution Station Transformers
- Pole Mounted Transformers
- Pad Mounted Transformers – separated into single and three phase units
- Poles

- Gang Operated Overhead Switches
- Pad Mounted Switchgear
- Underground XLPE Cable

7.2 Asset Condition Assessment

The cornerstone of any asset management plan is to understand the type of assets, the number of assets, and the condition of the assets owned by the corporation. Prior to the initiation of the GIS system in approximately 1996 all records were kept in paper or spreadsheet form. As well, detail on the various asset numbers, attributes and their condition were generally poorly documented or unknown. With the evolution of the GIS system and various database development projects, data collection and retention has improved dramatically. Commencing in approximately 1991 transformer attribute information was collected during PCB testing and manually input into a database. This program was completed in 1992. In 1996 in conjunction with deployment of our GIS, pole attribute data was collected electronically and downloaded into the GIS. By early 1993 all pole, transformer, conductor and switch attributes, for the entire distribution system, was collected and mapped in our GIS.

GPI decided not to engage a third party assessor to perform an independent Asset Condition Assessment because of a number of factors:

- Reliability statistics were very good;
- Plant inspections over the last few years has only identified a small number of assets at end of life;
- Asset condition assessments performed and on record at the OEB contain a large number of assumptions due to the fact that imperical data on asset condition in most utilities (as well as GPI's) is limited and therefore, asset age is a relatively good indicator to guage the life expectancy of an asset;
- GPI records of asset age and condition was excellent and in GPI's opinion better than most LDC's;
- Given the above factors the cost to hire a third party to perform an assessment exceed the value to be gained from it.

The major goal of an asset condition assessment is to approximate future capital expenditures over an extended horizon. With a good asset data base GPI felt it could produce an effective assessment in house. GPI's assessment is contained in the individual asset categories highlighted in Section 7.3.

GPI has recently completed an assessment on assets to meet the IFRS accounting standards. In its analysis, GPI utilized the Kinectrics Inc. Report number K-418033-RA-001-R000 dated July 8, 2010 titled "Asset Depreciation Study for the Ontario Energy Board" to assist with the determination of the useful lives of its assets. With each of the asset categories a typical useful life (TUL) has been determined and this life has been utilized to extrapolate the replacement of assets into the future over the next 20 year horizon.

7.3 Sustainment Strategies

7.3.1 Distribution Station Transformers

7.3.1.1 Condition Assessment

Yearly gas & oil analysis and monthly visual checks indicate that both Kerman and Baker Distribution Station Transformers are in fairly good condition. With the exception of Baker station having a non-operational tap changer which is hard wired and asset data exists within GPI.

7.3.1.2 GPI Sustainment Strategy

GPI's sustainment strategy is predicated on the following factors:

- Both distribution stations are greater than forty (40) years old and the transformation based on age profile have reached the Typical Useful Life (TUL) of 45 years for power transformers.
- 8.3kV distribution plant is of a similar age or older to the substation transformers and is also reached the TUL of 45 years.
- As distribution plant is replaced it is built to 27.6kV standards.
- Maintaining stations over the long term adds costs to the distribution system which would not be present if there were no stations at all. Eliminating stations does not generally require line extensions and the existing path or pole line is already in place.
- The capacity of 27.6kV feeders assigned to GPI from Hydro One and Niagara West Transformation Corporation already has the distribution stations embedded as part of their capacity. Therefore, converting the 8.3kV distribution plant to 27.6kV will not add load to the distribution or transmission system.
- Both Station transformers have adequate capacity to back each other up in case of failure.
- Testing of substation transformer oil is a very good predictor of when a transformer is reaching the end of its life. Regular testing allows time to make decisions about transformer replacement and capital investment is therefore, based on a proactive approach.

These factors have led GPI to adopt the following strategy:

- Existing 8.3kV circuits will be converted to 27kV and the load taken off the 8.3kV distribution system – thus eliminating the need to replace substation transformers.
- GPI's capital budget process will include projects which will promote the retirement of the 8.3kV distribution substation assets.

7.3.1.3 Budgets and Forecast

The impact of the above strategy on GPI's budget and or forecast is as follows:

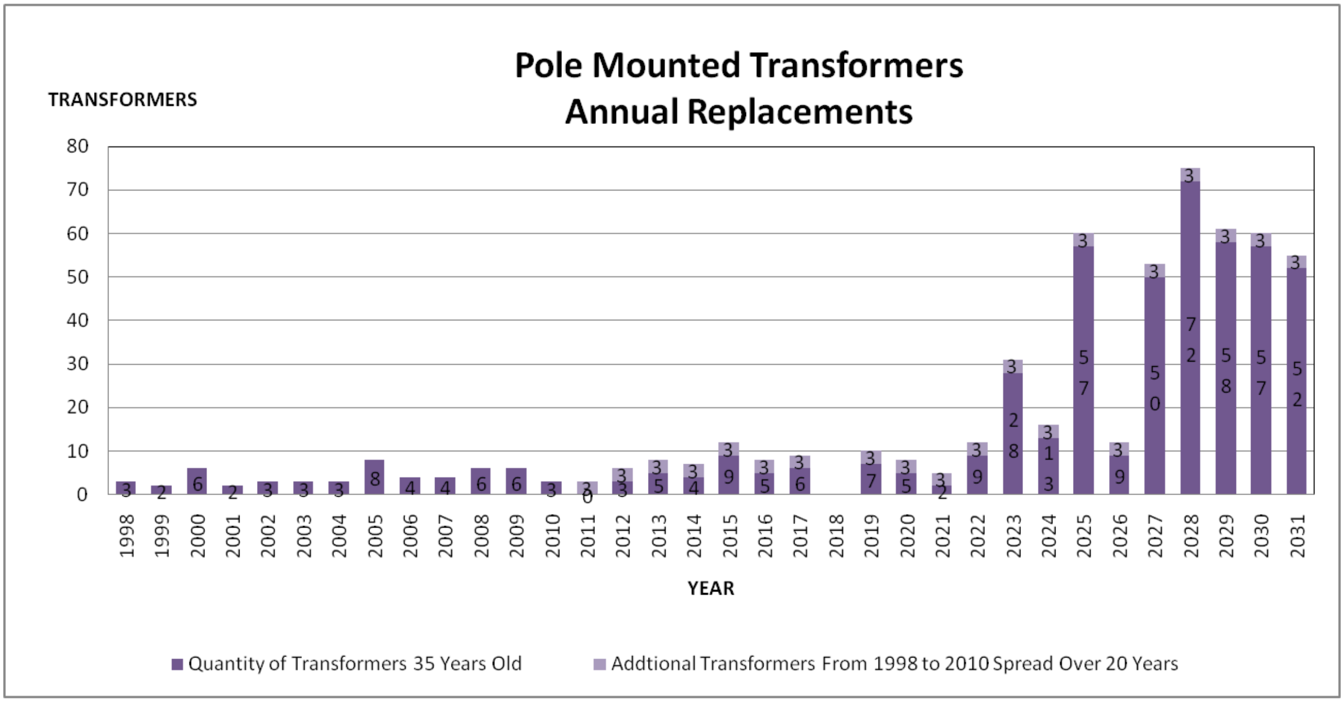
- There are no replacements scheduled for station transformers

7.3.2 Pole Mounted Transformers

7.3.2.1 Results of Asset Evaluation

Pole Mounted Transformers as a whole is a very large asset base. The age and condition of transformers is spread over a broad range 1963 to 2010 with an average age of 17 years old. GPI has used a Typical Useful Life (TUL) of thirty-five (35) years for Pole Mounted Transformers. When 35 years is added to the age distribution the number of potential replacements at end of life can be forecasted. This projection revealed 53 transformers that have met or exceeded the 35 year old TUL criteria in the years starting 1998 to 2010. This quantity of transformers has been distributed over the twenty year replacement projection which added 3 units per year starting from 2011 to 2031.

Shown below is a bar graph indicating the above mentioned asset evaluation which shows the number of Pole Mounted Transformers in GPI's distribution system that have or will reach their TUL of thirty-five (35) years:



7.3.2.2 GPI's Sustainment Strategy

GPI's sustainment strategy is predicated on the following factors:

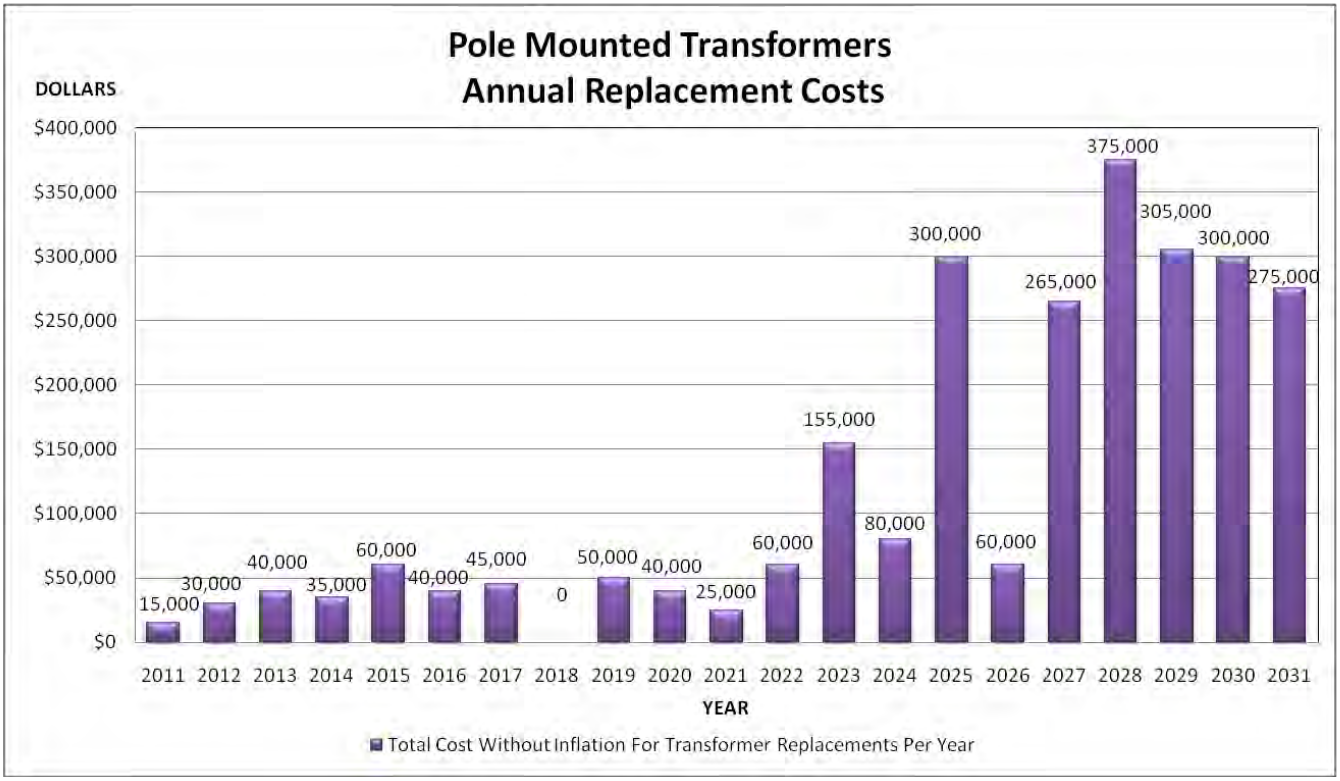
- The distribution transformer requires no maintenance.
- The outage impact of an individual transformer failure is limited to a very small number of customers and in some cases due to the rural nature of parts of the service territory only one customer is involved.

These factors have led GPI to adopt the following strategy:

- Inspect and monitor condition.
- Replace when conditions dictate - such as cracked bushings, leaking oil, etc.
- Replace when unit fails – thus, on a reactive replacement basis.
- Closely monitor the number of failures occurring between 2010 and 2017, if failure rates indicate an increasing trend change strategy to a preplanned replacement program to minimize the financial and operational affects on the large number of transformer replacements that could potentially occur between 2023 and 2031.

7.3.2.3 Budgets and Forecast

The relative costs in each year to replace units at end of life using an average unit replacement cost of $5,000.00 would be as shown in the bar graph below:



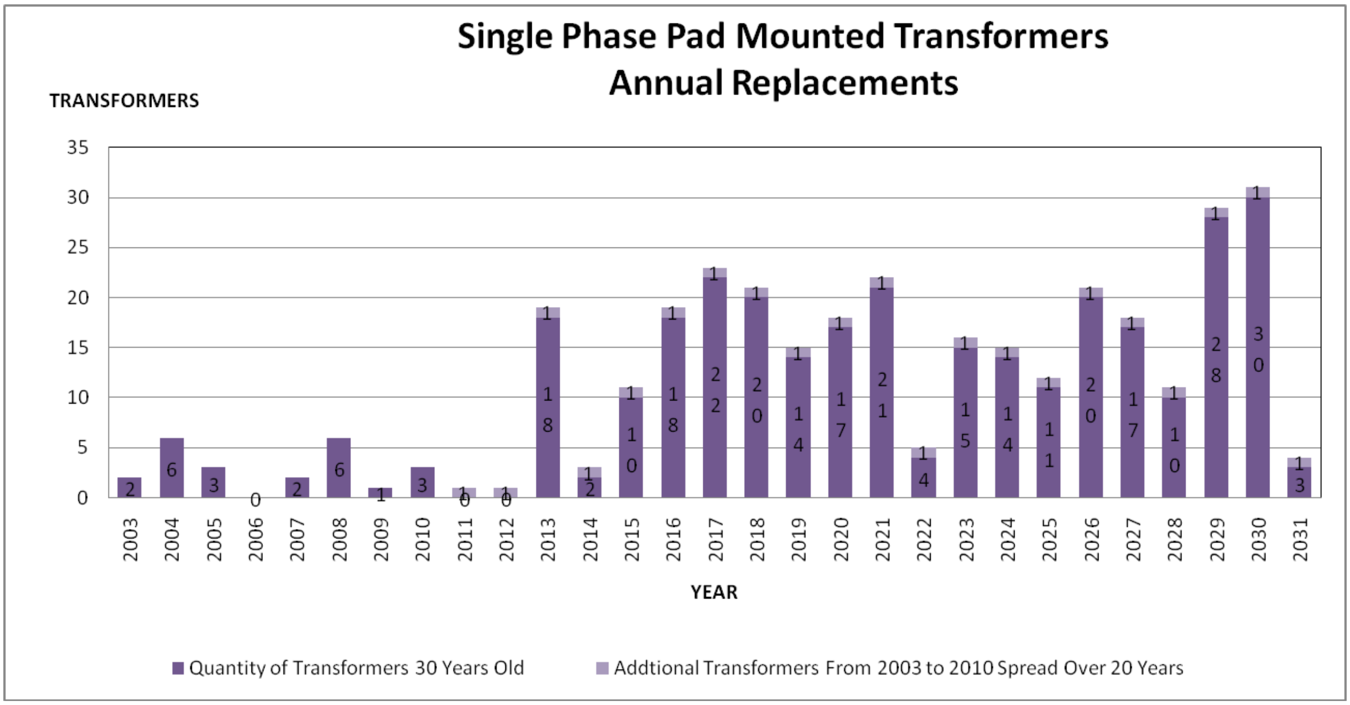
- Replacements under a reactive approach are part of the Operations and Maintenance budget.
- Replacements under a preplanned approach are part of the Capital Budget.

7.3.3 Single Phase Pad Mounted Transformers

7.3.3.1 Results of Asset Evaluation

Single Phase Pad Mounted Transformers as a whole is a large asset base. The age and condition of transformers is spread over a broad range 1973 to 2010 with an average age of 15 years old. GPI has used a Typical Useful Life (TUL) of thirty (30) years for Single Phase Pad Mounted Transformers. When 30 years is added to the age distribution the number of potential replacements at end of life can be forecasted. This projection revealed 23 transformers that have met the 30 year old TUL criteria in the years starting 2003 to 2010. This quantity of transformers has been spread over the twenty year replacement projection which added 1 unit per year starting from 2011 to 2031.

Shown below is a bar graph indicating the above mentioned asset evaluation which shows the number of Single Phase Pad Mounted Transformers in GPI's distribution system that have or will reach their TUL of thirty (30) years:



7.3.3.2 GPI's Sustainment Strategy

GPI's sustainment strategy is predicated on the following factors:

- The single phase pad mounted distribution transformer requires very little maintenance. Maintenance is generally confined to replacing faded warning labels and potentially painting the units.
- The outage impact of an individual transformer failure is limited to usually 10 to 12 customers.

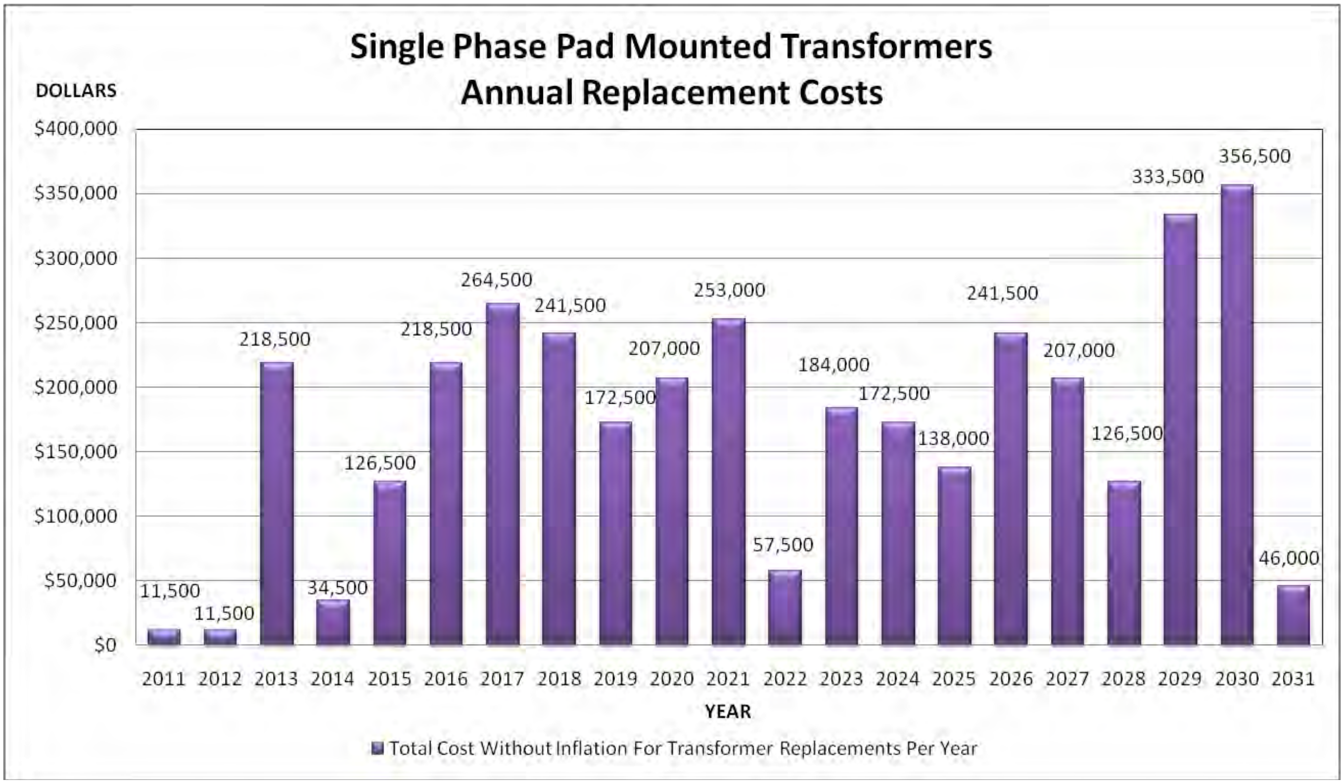
These factors have led GPI to adopt the following strategy:

- Inspect and monitor condition.

- Replace when conditions dictate - such as rusted tanks and frames, cracked bushings, leaking oil, etc.
- Replace when unit fails – thus, on a reactive replacement basis
- Continue with the preplanned ten (10) transformer replacements per year that warrant replacements as established from yearly inspections. If inspections reveal that transformer conditions are worsening increase the number of transformer replacements per year as required.

7.3.3.3 Budgets and Forecast

The relative costs in each year to replace units at end of life using an average unit replacement cost of $11,500.00 would be as shown in the bar graph below:



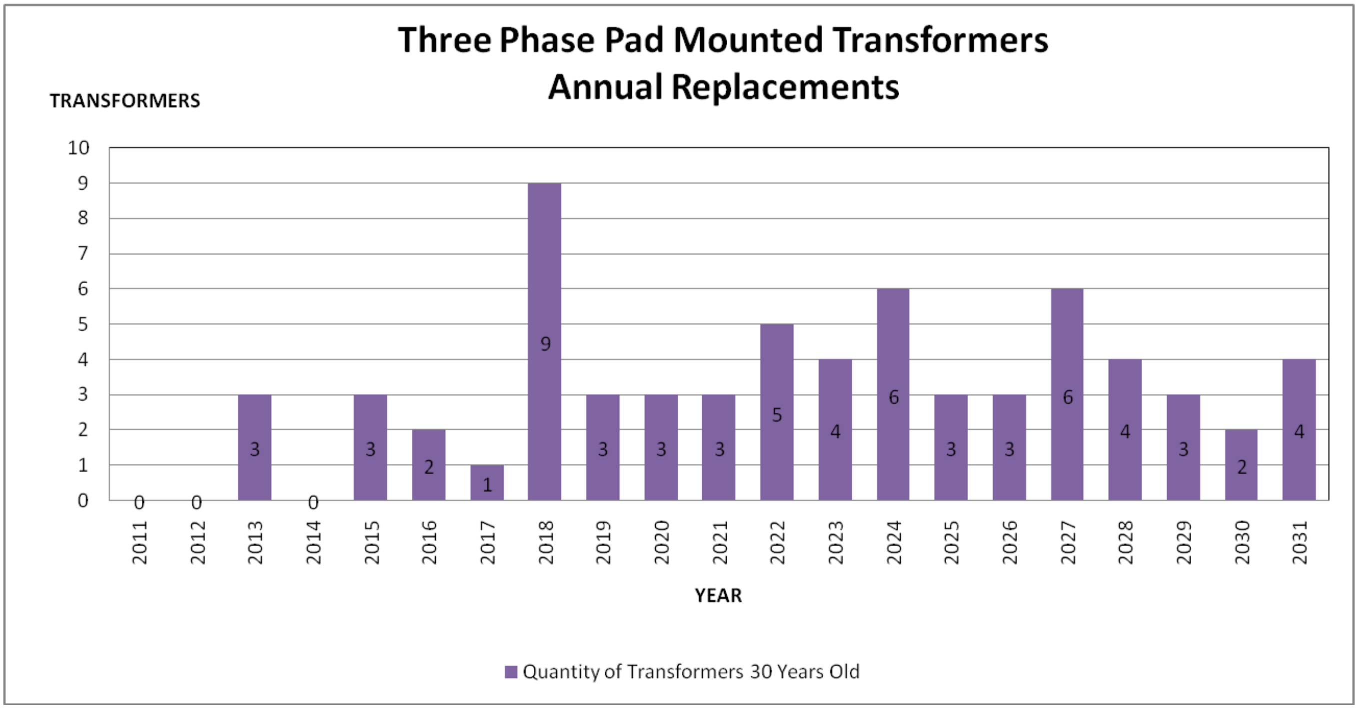
- Replacements under a reactive approach are part of the Operations and Maintenance budget.
- Replacements under a preplanned approach are part of the Capital Budget.

7.3.4 Three Phase Pad Mounted Transformers

7.3.4.1 Results of Asset Evaluation

Three Phase Pad Mounted Transformers as a whole is a very large asset base due to dollar value. The age and condition of transformers is spread over a broad range 1983 to 2010 with an average age of 14 years old. GPI has used a Typical Useful Life (TUL) of thirty (30) years for three Phase Pad Mounted Transformers. When 30 years is added to the age distribution the number of potential replacements at end of life can be forecasted. This projection revealed that we do not have any transformers reaching their TUL until the year 2013.

Shown below is a bar graph indicating the above mentioned asset evaluation which shows the number of Three Phase Pad Mounted Transformers in GPI's distribution system that have or will reach their TUL of thirty (30) years:



7.3.4.2 GPI's Sustainment Strategy

GPI's sustainment strategy is predicated on the following factors:

- The three phase pad mounted distribution transformer requires very little maintenance. Maintenance is generally confined to replacing faded warning labels and potentially painting the units.
- The outage impact of an individual transformer failure is limited to one service site either commercial or industrial.

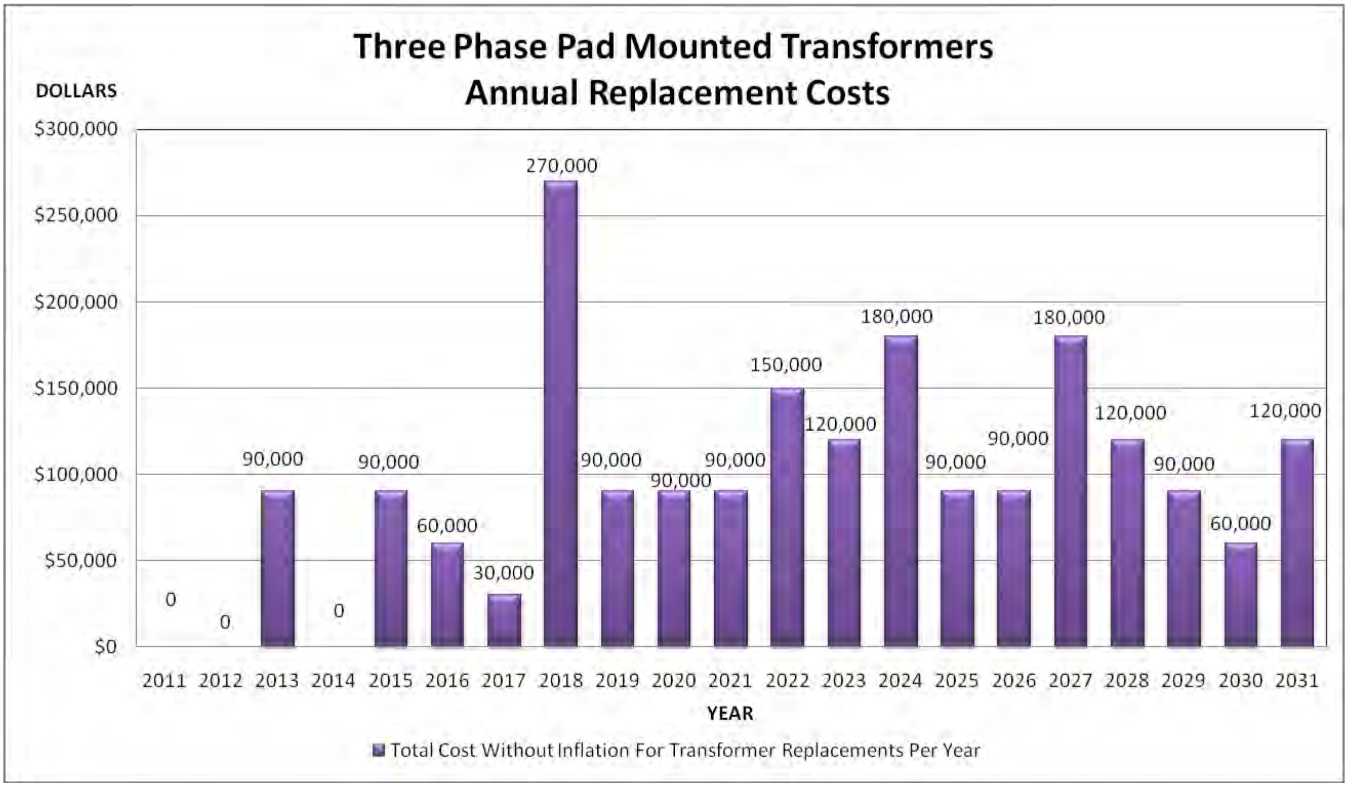
These factors have led GPI to adopt the following strategy:

- Inspect and monitor condition.
- Replace when conditions dictate - such as rusted tanks and frames, cracked bushings, leaking oil, etc.
- Replace when unit fails – thus, on a reactive replacement basis.

- Monitor conditions closely starting in year 2013, if failure rates indicate an increasing trend change to a preplanned replacement program to minimize the financial and operational affects.

7.3.4.3 Budgets and Forecast

The relative costs in each year to replace units at end of life using an average unit replacement cost of $30,000.00 would be as shown in the bar graph below:



- Replacements under a reactive approach are part of the Operations and Maintenance budget.
- Replacements under a preplanned approach are part of the Capital Budget.

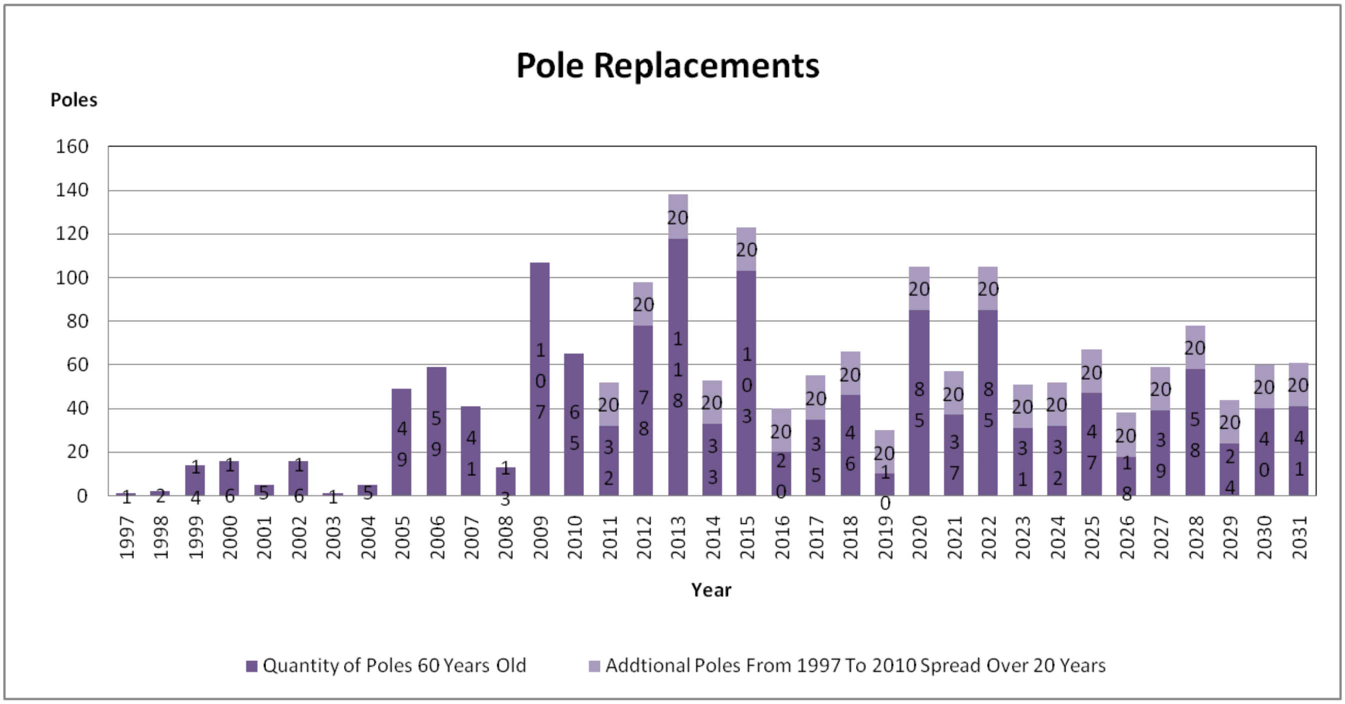
7.3.5 Poles

7.3.5.1 Results of Asset Evaluation

Poles by far have the largest number of assets within the distribution system. The age and condition of poles covers the full range of possibilities from newly installed to seventy-four (74) years for age with an average age of 30 years. GPI's inspection and testing over the last few years has resulted in very few pole replacements indicating that the overall pole condition is good.

GPI has used a Typical Useful Life (TUL) of sixty (60) years for Poles. When 60 years is added to the age distribution the number of potential replacements at end of life can be forecasted. This projection revealed 394 poles that have met the 60 year old TUL criteria in the years starting 1997 to 2010. This quantity of poles was spread over the twenty year replacement projection which added 20 poles per year starting from 2011 to 2031.

Shown below is a bar graph indicating the above mentioned asset evaluation which shows the number of Poles in GPI's distribution system that have or will reach their TUL of sixty (60) years:



7.3.5.2 GPI's Sustainment Strategy

GPI's sustainment strategy is predicated on the following factors:

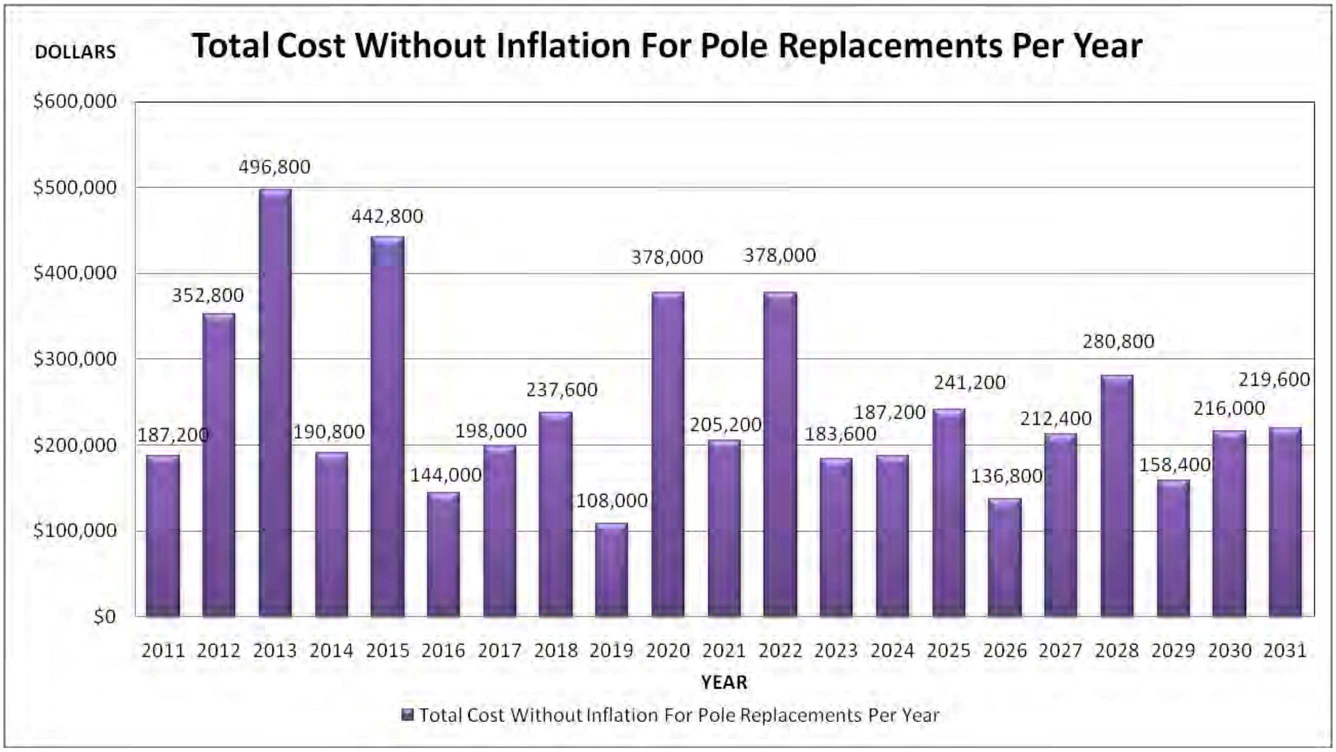
- The life expectancy of poles ranges from thirty-five (35) to seventy-five (75) years and condition is affected by many factors such as the soil condition and loading.
- GPI's inspection procedure is regulated by the OEB and as poles are inspected a determination is made as to whether they need to be tested. If they are tested their condition is rated as replace ASAP, replace in two (2) to three (3) years, or retest in six (6) years. Their condition is therefore, readily known at regular intervals allowing time for budgeting and replacement before they fail and cause an emergency response.
- A pole failure (depending on its function) can be a significant risk as the results of a failure could injure the public and result in lengthy interruptions in service to a widespread area and a large number of customers.

These factors have led GPI to adopt the following strategy:

- Inspect and monitor condition.
- Replace when conditions dictate replacement – thus, a proactive replacement basis.
- Continuing with the conversions from 8.32Kv to 27.6Kv distribution system will eliminate a substantial amount of the older poles from the system.
- Continue with the preplanned ten (10) pole replacements per year that warrant replacements as established from yearly inspections. If inspections reveal that pole conditions are worsening increase the number of pole replacements per year as required.

7.3.5.3 Budgets and Forecast

The relative costs in each year to replace units at end of life using an average unit replacement cost of $3,600.00 would be as shown in the bar graph below:



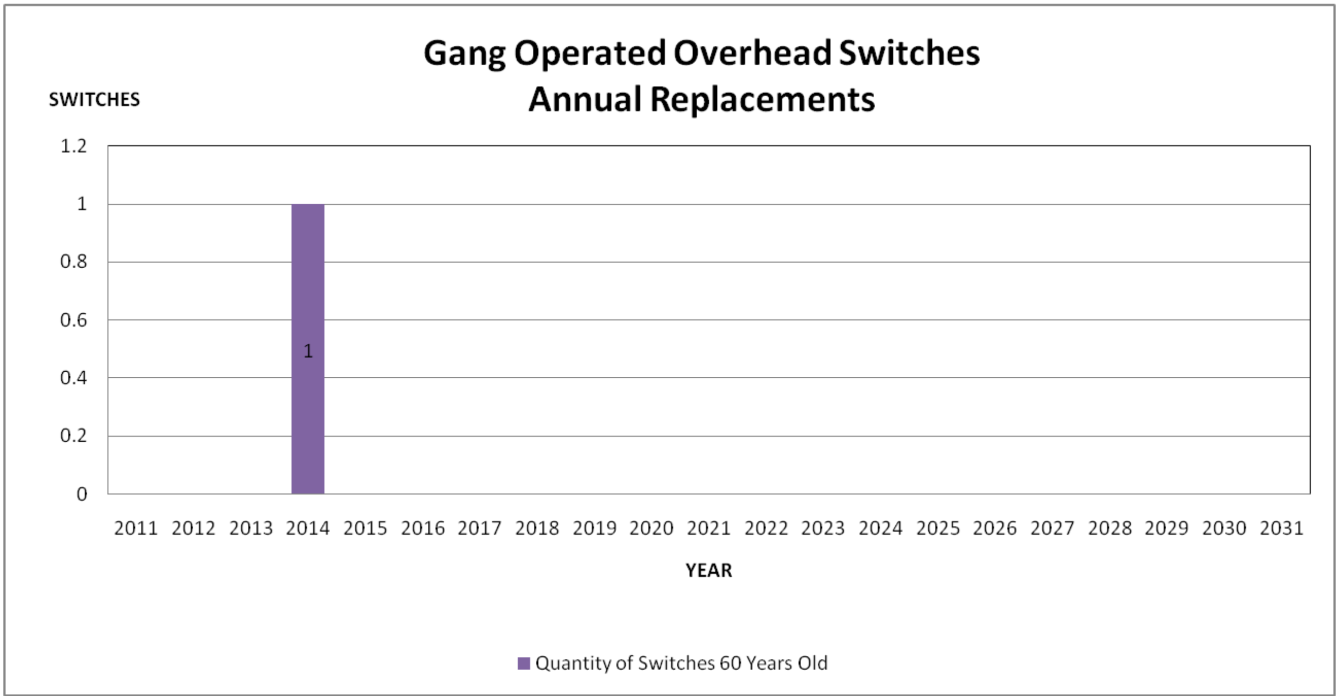
- Replacements under a reactive approach are part of the Operations and Maintenance budget.
- Replacements under a preplanned approach are part of the Capital Budget.

7.3.6 Gang Operated Overhead Switches

7.3.6.1 Results of Asset Evaluation

Gang Operated Overhead Switches are installed in various locations within the 27.6Kv distribution system with a total of 62 switches installed. The age of gang operated switches is spread over a broad range 1954 to 2010 with an average age of 21 years old. Their conditions are generally unknown due to lack of maintenance but because many switches are fairly new it is assumed that many are in very good condition. GPI has used a Typical Useful Life (TUL) of sixty (60) years for Gang Operated Overhead Switches. When 60 years is added to the age distribution the number of potential replacements at end of life can be forecasted. This projection revealed that in the next 20 years only one switch reached its TUL in the year 2014.

Shown below is a bar graph indicating the above mentioned asset evaluation which shows the number of Gang Operated Overhead Switches in GPI's distribution system that will reach their TUL of sixty (60) years:



7.3.6.2 GPI's Sustainment Strategy

GPI's sustainment strategy is predicated on the following factors:

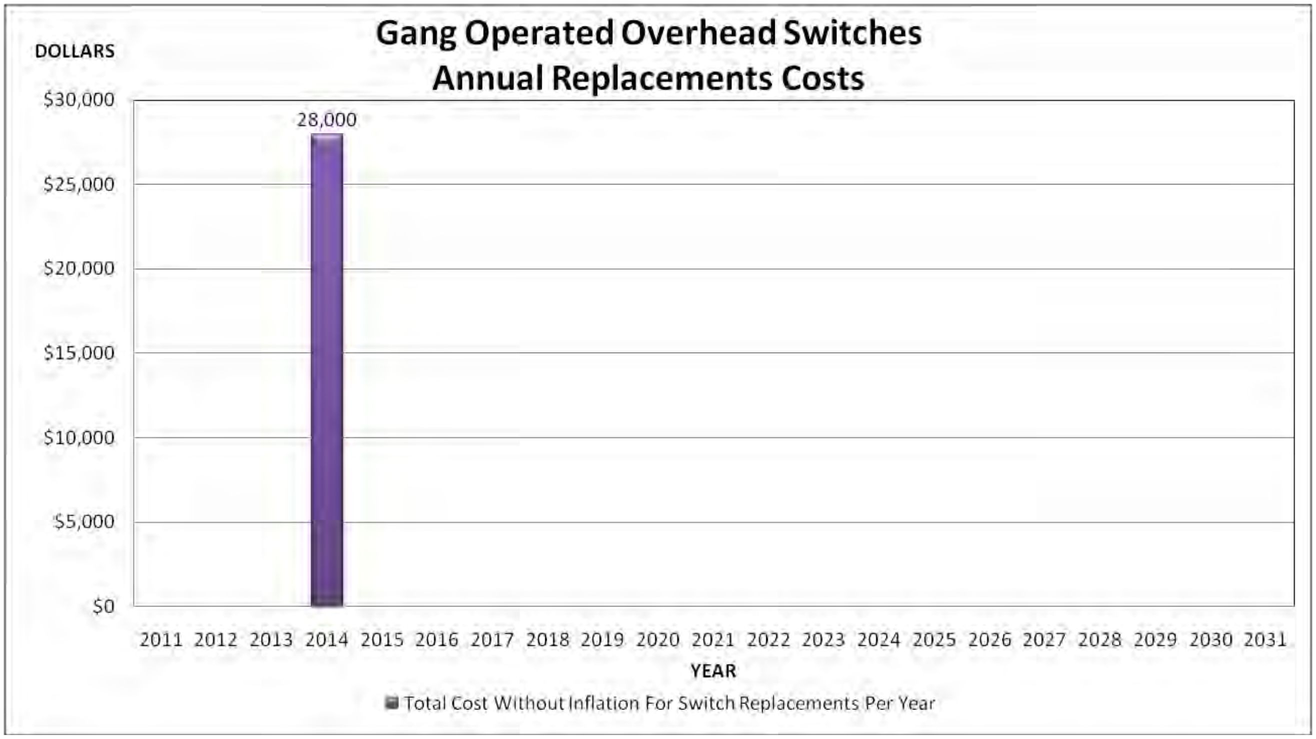
- The life expectancy of gang operated overhead switches is in the range of sixty (60) years.
- GPI's Inspection and Maintenance program for switches is expected to begin in 2012. This program will allow better decision making in the near future with respect to switch maintenance and replacement.
- A switch failure is low risk.

These factors have led GPI to adopt the following strategy:

- Inspect, maintain, and monitor condition.
- Replace when conditions dictate replacement – thus, a proactive replacement basis.

7.3.6.3 Budgets and Forecast

The relative costs in each year to replace units at end of life using an average unit replacement cost of $28,000.00 would be as shown in the bar graph below:



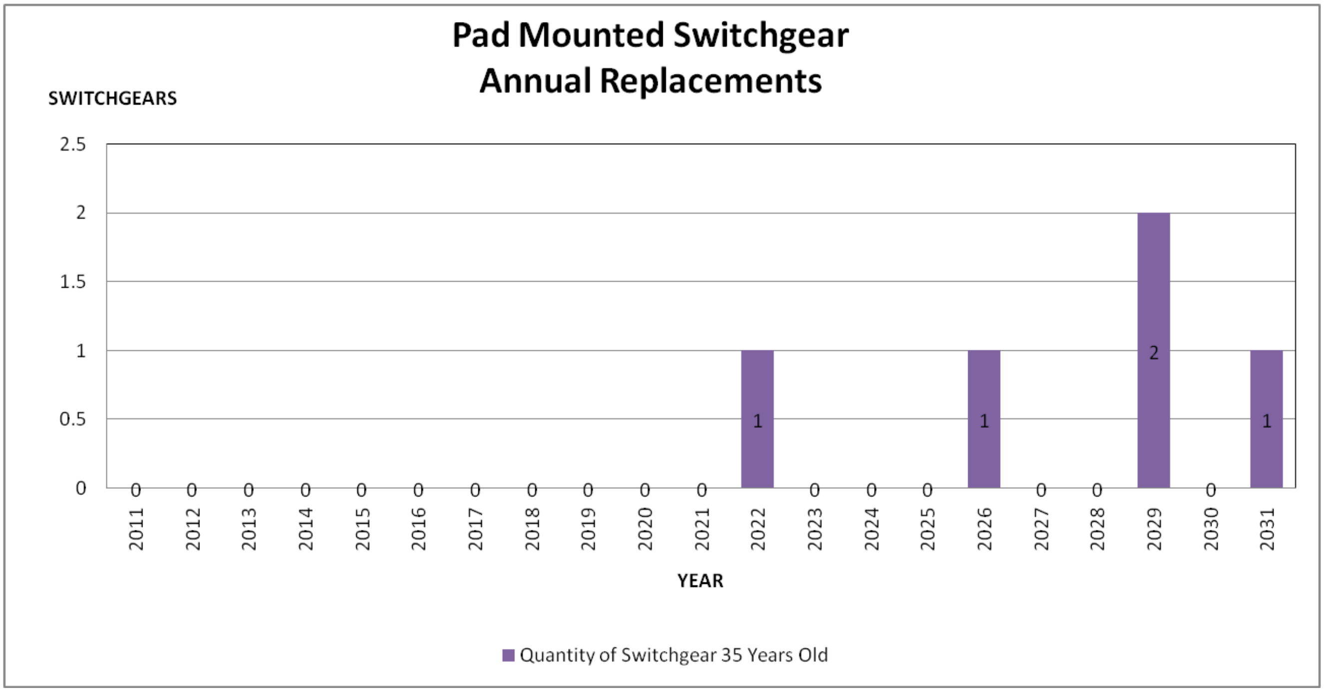
- Replacement is part of GPI's sustainment capital programs.
- The budgets for 2011 and 2012 do not have any replacements scheduled. The forecast reflects one (1) replacement required in 2014.

7.3.7 Pad Mounted Switchgear

7.3.7.1 Results of Asset Evaluation

Pad mounted switchgear units are installed in very small numbers within the distribution system for a total of ten (10) units. The average age of the switchgear is fourteen (14) years. Their condition is very good as the condition of the switchgear is monitored during the inspection process. GPI has used a Typical Useful Life (TUL) of thirty-five (35) years for pad mounted switchgear. When 35 years is added to the age distribution the number of potential replacements at end of life can be forecasted. This projection revealed that the first unit reaching its TUL will occur in the year 2022.

Shown below is a bar graph indicating the above mentioned asset evaluation which shows the number of Pad Mounted Switchgear in GPI's distribution system that will reach their TUL of thirty-five (35) years:



7.3.7.2 GPI's Sustainment Strategy

GPI's sustainment strategy is predicated on the following factors:

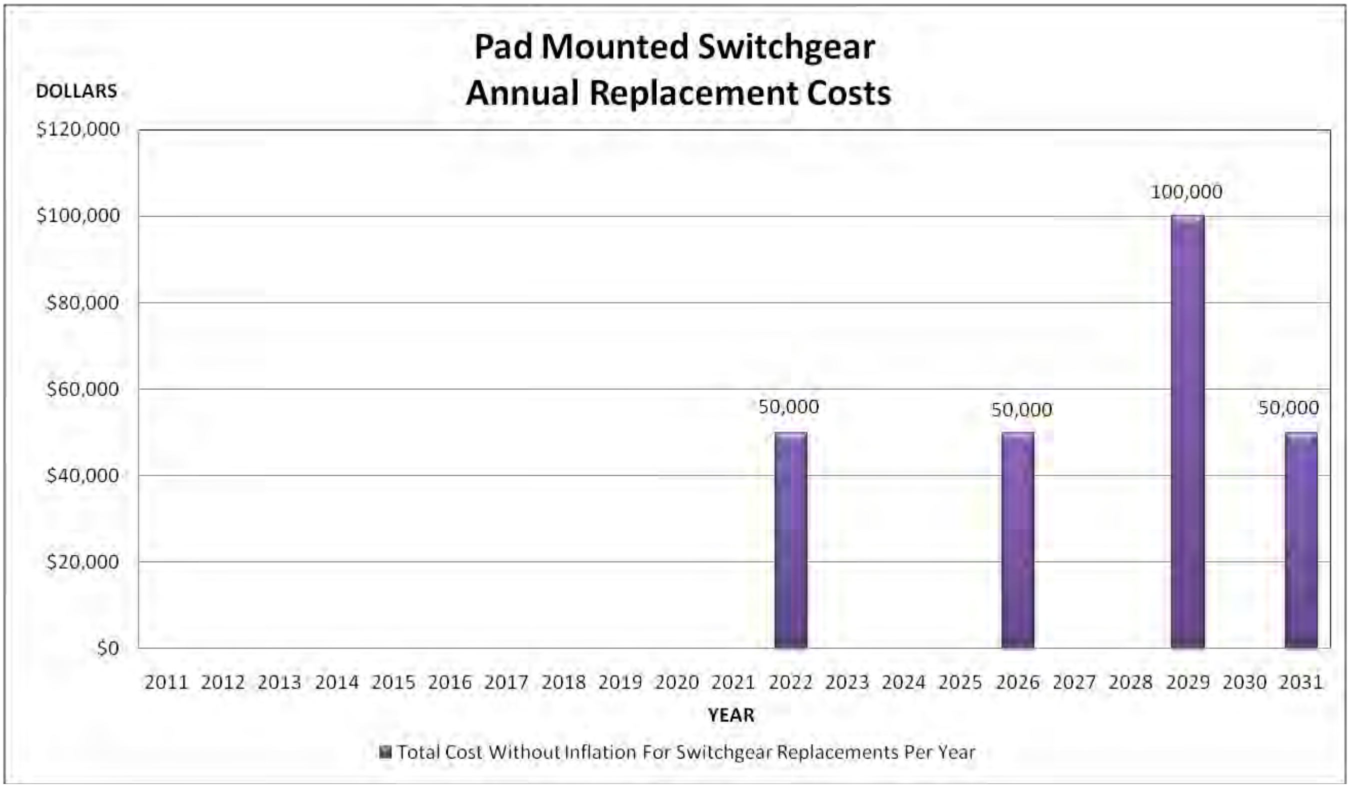
- The life expectancy of pad mounted switch gear units is in the range of thirty-five (35) years.
- Continue with the inspection program to allow better decision making with respect to switch maintenance and replacement.
- The impact of a switch failure is significant risk. A significant customer outage would likely occur and the safety of the public and staff would be potentially impacted.

These factors have led GPI to adopt the following strategy:

- Inspect, maintain, and monitor condition.
- Replace when conditions dictate replacement – thus, a reactive replacement basis.
- Monitor conditions closely on a three year bases, if failure rates indicate an increasing trend change to a preplanned replacement program to minimize the financial and operational affects.

7.3.7.3 Budgets and Forecast

The relative costs in each year to replace units at end of life using an average unit replacement cost of $50,000.00 would be as shown in the bar graph below:



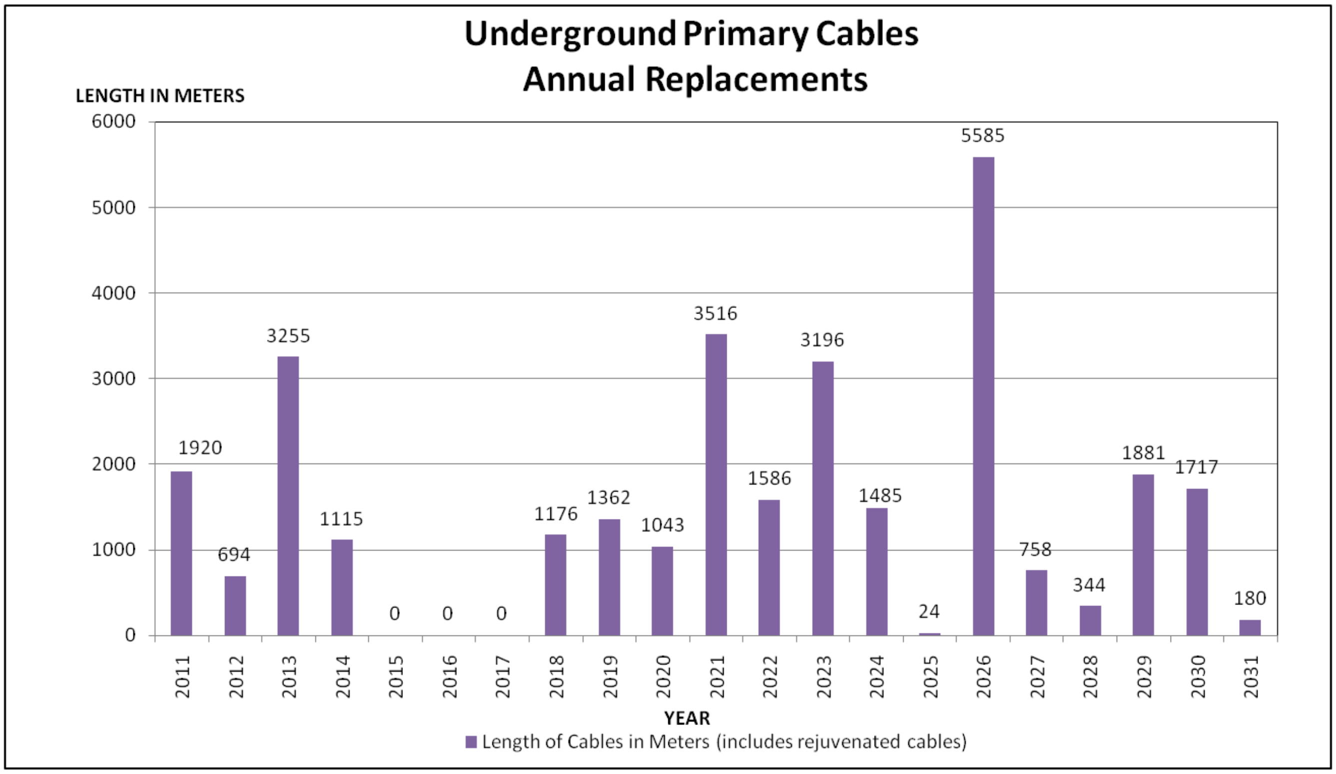
- Replacements under a reactive approach are part of the Operations and Maintenance budget.
- Replacements under a preplanned approach are part of the Capital Budget.

7.3.8 Cross-Linked Polyethylene (XLPE) Underground Cables

7.3.8.1 Results of Asset Evaluation

Cross-linked polyethylene (XLPE) underground cables are installed in mostly underground fed residential subdivisions. A small portion of cable serves as distribution feeders from our overhead distribution system where necessary. The average age of cables is fourteen (14) years old. Their condition is generally very good as we have experienced only one fault over the past 25 years. GPI has used a Typical Useful Life (TUL) of thirty-five (35) years for underground cables. When 35 years is added to the age distribution the number of potential replacements at end of life can be forecasted. This projection revealed that starting in 2011 a total of 1.9km of underground cables will have reached their TUL of 35 years.

Shown below is a bar graph indicating the above mentioned asset evaluation which shows the number of Underground Cables in GPI's distribution system that will reach their TUL of thirty-five (35) years.



7.3.8.2 GPI's Sustainment Strategy

GPI's sustainment strategy is predicated on the following factors:

- The life expectancy of direct buried cross-linked polyethylene (XLPE) underground cables (of the newer variety – TRXLPE) is in the range of twenty-five to thirty-five (35) years. However, older cables which were built with the technology available at the time of manufacture have an uncertain life expectancy (per Kinectrics report).
- GPI's Inspection and Maintenance program covers the terminations of cable only – these are exposed in pad mounted equipment and riser poles. Cable condition is only known for cables which fail in service. Failure information is tracked as part of the "cause" in GPI's reliability statistics. Cable replacement decisions would be based on failure history. There has been only one (1) cable failure in the last 25 years at GPI.
- The impact of a cable failure is low risk. Customer outages are likely to remain within a residential subdivision and all cables can be isolated due to a loop system design (there is usually another way to supply the load).
- The safety of the public is not likely to be impacted because the cables are buried and not exposed.

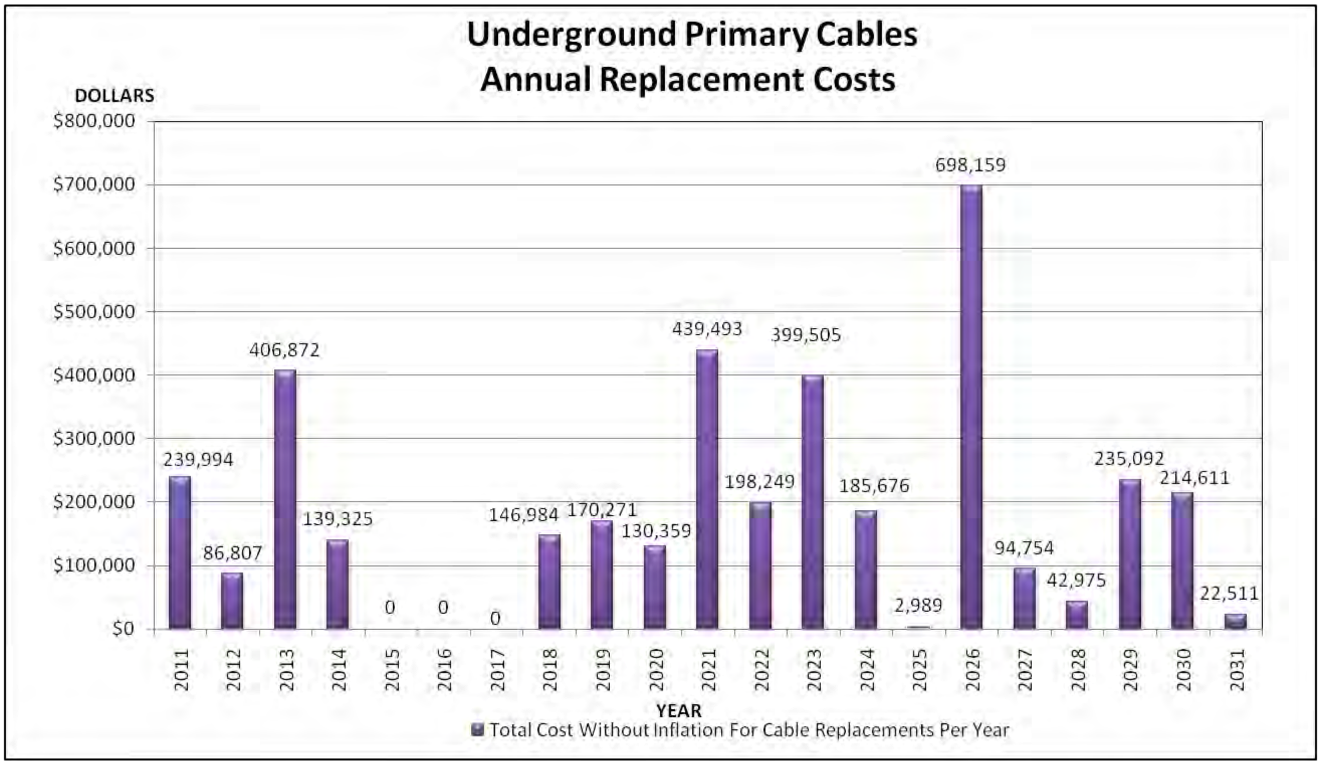
These factors have led GPI to adopt the following strategy:

- Monitor the number of cable failures.

- Create a systematic replacement program when failure results indicate a systemic failure of that particular age or type of cable – thus, a reactive replacement basis.
- Continue with approximately 2500 meters per year of cable segment rejuvenation by injecting cables with CableCURE XL fluid (known in the industry as **Silicon Injection**). This cable rejuvenation process should extend the cable life by at least twenty years (20).
- Monitor the results of cable rejuvenation along with cable failures. If failure rates indicate an increasing trend change to a preplanned replacement program.

7.3.8.3 Budgets and Forecast

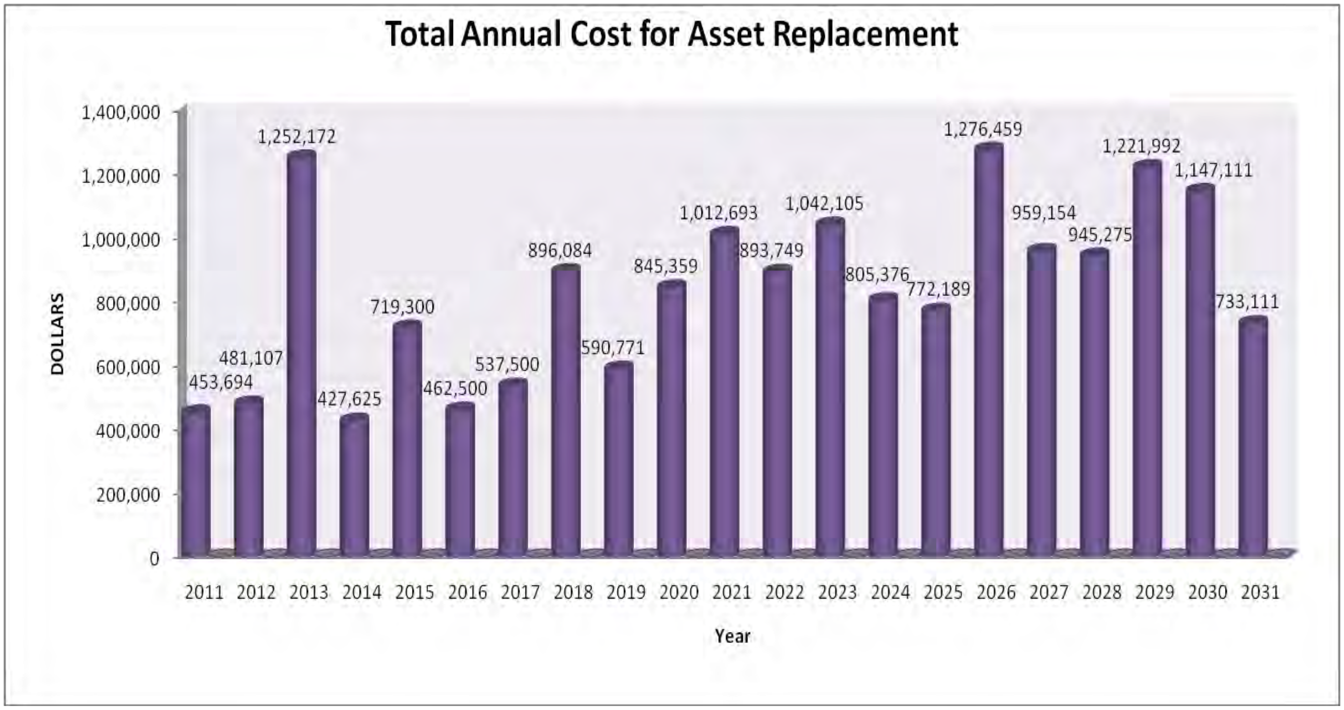
The relative costs in each year to replace cables at end of life using an average replacement cost of $125.00 per kilometer would be as shown in the bar graph below:



- Replacements under a reactive approach are part of the Operations and Maintenance budget.
- Replacements under a preplanned approach are part of the Capital Budget.

7.4 Total Annual Cost for Asset Replacements

The total annual costs (without inflation projection) in each year to replace the above mentioned assets listed in content 7.1 at end of life would be as shown in the bar graph below:



The average annual asset replacement cost for the 20 year period is $832,158.00.

8 Discretionary Capital Projects

Apart from the sustainment of existing assets in the distribution system there are other types of investment required in the distribution system. The first type can be called demand expenditures and they are required to supply the needs of a new customer or to enhance reliability in an area where system capacity is constrained. The second type of expenditure is called discretionary. These expenditures alleviate potential risks associated with the utility's goals.

8.1 Typical Considerations in Developing New Discretionary Projects

Typically new assets are required as a result of the following drivers:

- Load Growth
- Security of Supply and Level of Redundancy
- Capacity of Assets
- Voltage Regulation
- Safety – Public and Staff
- Environmental Compliance

8.1.1 Load Growth

Load growth is influenced by a number of factors including:

- Population Growth

- Economy
- Effectiveness of conservation programs

In order to determine how growth might affect the distribution system a number of areas need to be analyzed. These include population forecasts, the number of new connections, the type of connections, and historical demand.

8.1.1.1 Population Growth

The forecasted population growth for Grimsby as published in the document titled "Niagara Region Water and Wastewater Master Servicing Plan Study Municipal Class Environmental Assessment" published in April 29, 2010 as posted on the Niagara Region web site http://www.niagararegion.ca/living/water/projects/master-servicing-plan/default.aspx is depicted below.

	2006	2011	2016	2021	2026	2031
Grimsby	24,900	27,000	29,400	31,000	32,100	32,800
Percent Change			9	15	19	21

Clearly the population is expected to rise by twenty two (21) percent between 2011 and 2031 - on average 1.1 percent per year.

8.1.1.2 Number of New Connections

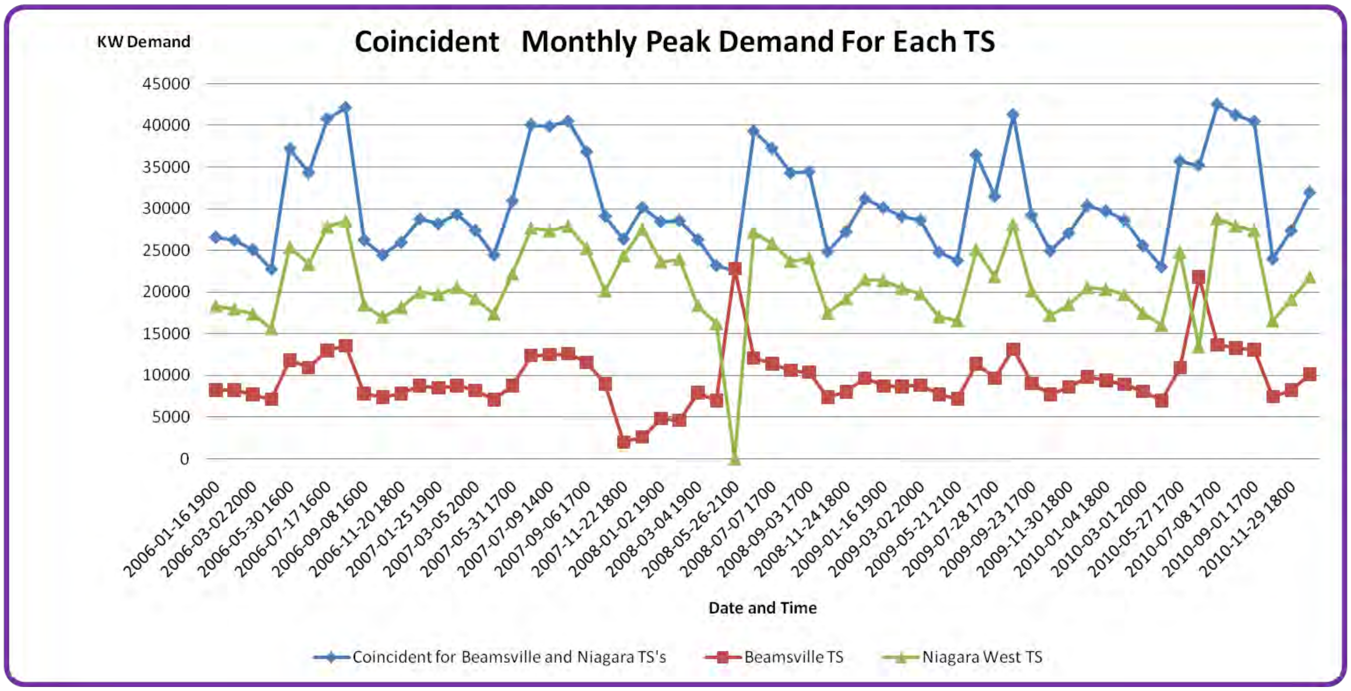
GPI's new connections have slowed since 2004 as compared with the latest six (6) years. However, the year to year totals show a fairly stable pattern. The following table shows the specifics. It should be noted that these connections represent low voltage connections.

	2004	2005	2006	2007	2008	2009	2010	2011
January	39	17	20	10	17	0	6	5
February	16	1	33	0	4	10	15	11
March	40	21	2	5	0	9	13	11
April	40	0	5	1	16	0	9	
May	31	25	7	15	14	0	8	
June	38	14	7	19	15	0	15	
July	30	12	0	11	3	22	7	
August	30	6	15	16	2	19	9	
September	37	8	15	54	8	8	24	
October	17	7	9	21	5	17	28	
November	21	0	9	21	8	41	23	
December	44	2	0	26	53	20	26	
Totals	383	113	122	199	145	146	183*	

*In 2010 this number includes both new connections as well as upgrades. This reflects new reporting requirements dictated by the OEB which took effect on Jan 1, 2010.

8.1.1.3 Peak Demand

GPI has been recording the monthly demand peaks at each of the Two (2) TS's. The data from each station for the period from 2006 to 2010 is shown in the following graph:



The demand is based on hourly data provided from the IESO which is not adjusted for losses and monthly peaks between stations are coincident. It is clearly evident that there are no distinct growth patterns in the peak demand for either of the TS's. Also evident is that 2010 produced slightly higher demand and the peaks at each station are very stable.

8.1.1.4 Conclusion

Although the economy is currently very slow it is none the less expected to grow over the twenty (20) year timeframe of this plan. At this time it is unclear how the population growth will specifically affect the distribution system. Growth over the period from 2006 to 2010 has not appreciably affected the peak demand. Future revisions of this plan will need to account for potential growth as and if it materializes.

8.2 Discretionary Capital Projects Prioritization Model

In the past GPI's asset strategy was built on rebuilding 8kV distribution lines at 27.6kV to support the elimination of its aging 8kV distribution stations. This program is anticipated to be completed by the end of 2013. Prior to commencement of budget proceedings for 2013 GPI will need to develop a new asset strategy and a means to prioritize discretionary capital projects. Other utilities have developed prioritization strategies either in house or through the assistance of third party consultants. These strategies will be reviewed and GPI will prepare a model that takes into consideration GPI's specific circumstances.

It should be noted that sustainment type projects are not evaluated using this model. Sustainment projects are not discretionary because an existing asset is at the end of its useful life and must be replaced. There is no discretion involved.

8.3 Past Capital Project Decision Process

Notwithstanding GPI's asset strategy leading up to 2012 as noted above in Section 8.2 it is still necessary to evaluate individual projects based on a number of factors which are specific to GPI's service territory. In preparation for the setting budgets of the past the following considerations were made to decide which projects should be included in any given year:

- Financial
  - Reduction of future operating costs
  - Reduction of losses
- Reliability
  - Impact to SAIDI, SAIFI, and power quality (low voltage, etc.)
- Safety
  - Public
  - Staff
- Customer Relations
  - Impact/effect on customers
- Regulatory
  - Compliance with regulatory statutes
- Environmental
  - Elimination of risk of contamination to the environment – oil spills

Once the priorities are decided, a preliminary project design and estimate is made for each project.

8.4 2011 and 2012 Discretionary Capital Projects

The discretionary projects in the 2011 and 2012 budgets were evaluated using best engineering judgment based on the experience of the Director of Engineering and the Line Superintendent. The criteria used is noted above in Section 8.3

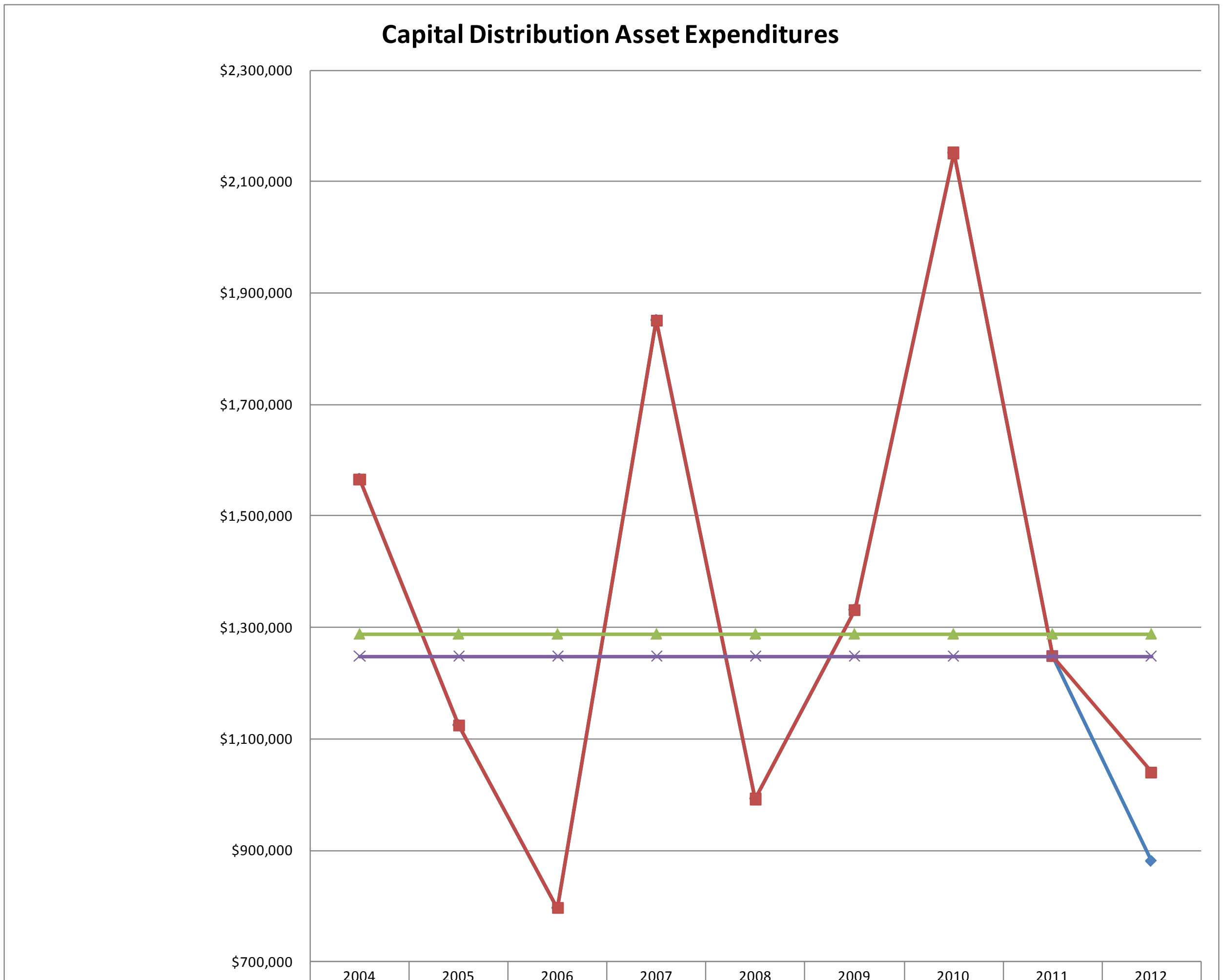
For more details on the discretionary projects for 2011 and 2012 year refer to Appendix-E and Appendix-F.

8.5 Five Year Forecast

As a result of GPI's asset strategy leading up to 2012 a forecast was not necessary as the projects were dictated by the need to eliminate 8kV distribution lines and the expenditure in each year was kept relatively stable. A graph depicting the actual expenditures (distribution assets not including smart meters) plus projections for 2011 and 2012 is shown below. As shown in the graph the average expenditure over the years 2004 to 2012 (based on CGAAP) is $1,288,643 and the median slightly below at $1,248,553.

GPI's intention is to create a five year forecast to coincide with its newly developed asset strategy. For purposes to support GPI's cost of service rate application in 2011 a 3 year forecast has been developed using the data from the asset condition assessment as a proxy for the approximate minimum cost in both 2013 and 2014. No specific projects are yet available for 2013 or 2014.

At this time we are forecasting for 2013 GPI will continue to focus on cleanup work in eliminating all 8kV distribution lines to lead to the elimination of both 8KV distribution stations. After which, GPI will focus on utilizing the DAMP for a guide in creating and prioritizing asset replacement projects. As this DAMP revealed, GPI will have to spend on average (minimum) of $832,000.00 per year (without inflation projection) to replace aging assets in order to continue to provide a cost effective, safe and reliable electrical service to our customers for the next twenty (20) years to follow. This average coupled with the historical expenditures would indicate the GPI's capital expenditures on distribution assets should be in the range of $832,000 to $1,300,000.



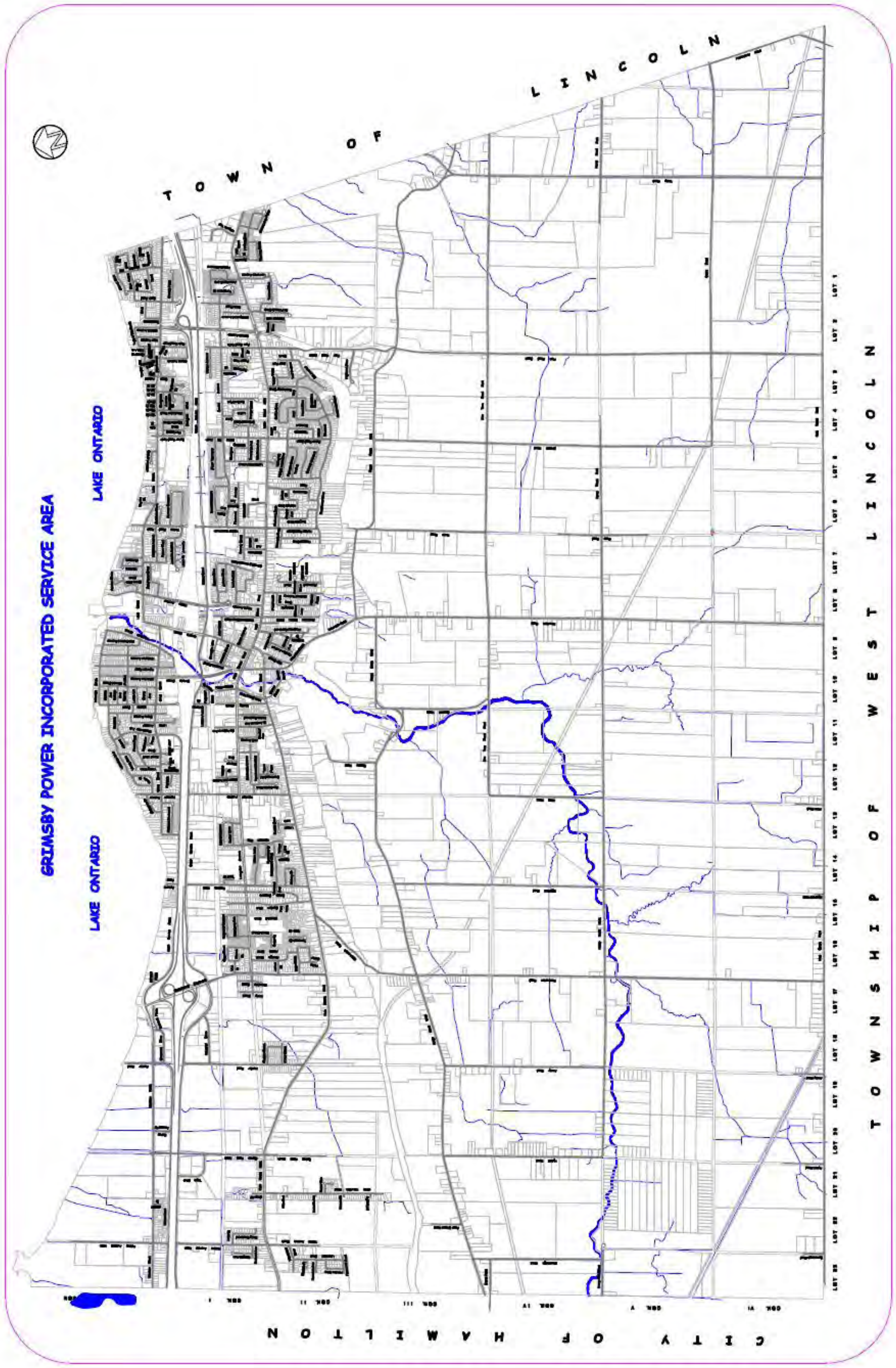
	2004	2005	2006	2007	2008	2009	2010	2011	2012
Capital Project Expenditures (IFRS)	$1,566,023	$1,124,268	$796,443	$1,850,999	$992,348	$1,331,215	$2,151,170	$1,248,553	$880,323
Capital Project Expenditures (CGAAP)	$1,566,023	$1,124,268	$796,443	$1,850,999	$992,348	$1,331,215	$2,151,170	$1,248,553	$1,039,741
Average	$1,288,643	$1,288,643	$1,288,643	$1,288,643	$1,288,643	$1,288,643	$1,288,643	$1,288,643	$1,288,643
Median	$1,248,553	$1,248,553	$1,248,553	$1,248,553	$1,248,553	$1,248,553	$1,248,553	$1,248,553	$1,248,553

Appendix A - Summary of Assets (as at December 31, 2010)

Category	Original Cost	% of Total
Distribution Stations	$143,555	0.55%
Distribution Lines - Overhead	$9,740,197	37.5%
Distribution Lines - Underground	$8,667,548	33.4%
Distribution Transformers	$7,419,309	28.6%
Total	$25,970,609	

Detail extracted from Grimsby Power Incorporated – Audited Financial Statements 2010.

Appendix B - Service Territory



Appendix C - Distribution System Maintenance and Inspection Program

GRIMSBY POWER INC.

Distribution System Maintenance and Inspection Program

Table of Contents

9 General

9.1 Introduction

A Distribution System Maintenance and Inspection Program is a key component to system reliability, customer/public safety and worker safety. The purpose of this program is to document the requirements for the maintenance or inspection of all key distribution system assets. Each distribution system asset has its own program and within each program a procedure is identified as to how the maintenance and inspection will be performed. The procedure identifies the specific asset and assigns responsibility for the delivery of the program.

It is noted that this procedure is not yet fully complete or implemented. The program includes completed sections on assets which have established protocols and on assets which are in the process of being implemented. Assets for which the program has not been initiated are in a preliminary state and information in this document may only be the basic template information. Each program identifies whether the program is *established*, in the *implementation* phase, or is in the *development* phase.

This procedure is reviewed annually and is subject to the continuous improvement process.

The following maintenance and inspection programs are detailed in this procedure:

- Line Clearing and Tree Trimming Maintenance Program
- Substation Maintenance Program
- Distribution Plant Inspections
- Off Road High Voltage Line Inspections
- Thermography Inspection Program
- Switch Maintenance Program

10 Programs

10.1 Line Clearing and Tree Trimming Maintenance Program

10.1.1 Introduction:

The purpose of this program is to clear all lines from the encroachment of trees and branches to eliminate, as best as possible, tree contact with lines. This is a major contributor to improved reliability.

10.1.2 Status of Program

Established

10.1.3 Historical Information

In past years there has not been a defined area program in progress due to the rate of growth of different species in different areas. Basically a street by street assessment was made in each year to determine where tree trimming was required. In addition to this Grimsby Power has closely monitored its four main 27.6kV feeders. The main feeders have been rotated annually. Any tree concerns by customers were addressed as they were reported. An annual patrol is done to verify any if additional areas of concern should be added to the designated trimming contract for the year.

In 2011 GPI is reverting back to trimming in designated areas on an annual basis plus additional trimming in other areas if required.

10.1.4 Definition of Geographic Areas and Frequency of Program:

This program is organized on a four year rotating cycle. The boundaries of each tree trimming area are based on natural boundaries such as the Niagara Escarpment;Lake Ontario and municipal street names. The geographic areas are defined as follows:

- Area#1 - Lake Ontario to the north; Niagara Escarpment to the south; Kelson Ave to the west; Roberts Rd. to the east.
- Area#2- Lake Ontario to the north; Niagara Escarpment to the south; Roberts Rd. to the west; Nelles Rd. to the east.
- Area#3- Lake Ontario to the north; Niagara Escarpment to the south; Nelles Rd. to the west; Bal Harbour subdivision to the east.
- Area #4 – Niagara Escarpment to the north; Mud St to the south; Bowslaugh Rd. to the west; Inglehart Rd. to the east.
- Area #5 – Niagara Escarpment to the north;Mud St to the south; Inglehart Rd. to the west; Russ Rd. to the east.
- Area #6 – Niagara Escarpment to the north;Mud St to the south; Russ Rd. to the west;Fairbrother and Thirty Rd. to the east.

See Map included as Appendix A

The timing of each geographic area as completed in the past, present, and future is as follows in Table A:

TABLE A:

Year	Area# 1	Area #2	Area#3	Area#4	Area#5	Area#6
2002	X					
2003		X				X
2004			X			
2005	X	X		X		X
2006						
2007			X			
2008						
2009	X			X		
2010			X		X	
2011		X				X
2012	X			X		
2013			X		X	
2014	X	X				
2015			X	X		

In the years from 2002 to 2010 tree trimming was completed on a street by street basis. The areas in where the majority of tree trimming occurred are denoted by the "X" in the Table above.

10.1.5 Line Clearing Specifications

All trees, limbs and branches shall be trimmed so that the minimum clearance to the nearest conductor is:

- 4 meters for all primary (high voltage) distribution lines
- 1 meter for all secondary (voltages less than 750V) lines

Note – these specifications are the same as the Ontario Electrical Safety Code Rule 75-326(2) (Tree Trimming).

In locations where it would be considered inappropriate to trim to such clearances then the Contractor will consult with and obtain approval from GPI for alternate clearances.

Prune all branches to direct growth away from the conductors. Any dead wood that is clear of the lines but is above or adjacent to the lines shall be removed. All Trees are to be trimmed to an eye appealing +perspective in residential areas.

All primary services supplying GPI customers are to be cleared within the road allowance or within 20 meters of the main distribution line if off road. Trimming beyond these limitations are Customer owned and are the responsibility of the customer.

All secondary services supplied from a transformer or secondary bus on the main line to be cleared to the house.

10.1.6 Responsibility

Administration of the Program Line Superintendent
Work Protection Line Superintendent.

10.1.7 Job Number

Job # - 51350000
Title – Overhead Distribution Lines and Feeders Right of Way

10.2 Substation Maintenance Program

10.2.1 Introduction

The purpose of the Substation Maintenance Program is to identify any issues and remediate them as quickly as possible to ensure continuous operation of each substation and eliminate any danger to the public. This program consists of monthly inspections and annual oil analysis of all substation power transformers.

10.2.2 Location and Identification of Substations

The substations that are part of this program are as follows in Table B:

TABLE B:

Substation Name	Address	Installed Capacity (MVA)	# of Trans	# of Banks	# of Recl's	# of Fdrs
Kerman DS	Kerman Ave . & CNR	5	1	1	0	2
Baker DS	Baker Rd. & Clarke St. (S.S. Rd)	7.5	1	1	3	1

10.2.3 Monthly Substation Inspection

10.2.3.1 Introduction

The purpose of this inspection is to identify any deficiencies and to verify that the substation is not going to pose any safety concerns to the public. Each station has a specific checklist which is to be completed and signed off by the inspector. A sample form is included in Appendix B.

10.2.3.2 Status of Program

Established

10.2.3.3 Responsibility

Completing this Inspection Director of Engineering
Administration of Deficiencies Line Superintendent

10.2.3.4 Job Number

Job # - 50160000
Title – Distribution Station Equipment Operating Labour

10.2.4 Annual Oil Tests

10.2.4.1 Introduction

Oil tests on substation transformers have been proven effective in identifying internal transformer issues before major faults occur which reduce reliability and increase cost. GPI will perform both oil quality and gas-in-oil tests at least once per year. Additional oil tests will be completed upon recommendations by the service firm providing the analysis and as required.

10.2.4.2 Status of Program

Established

10.2.4.3 Responsibility

Administration of Program Line Superintendent
Administration of Deficiencies Line Superintendent

10.2.4.4 Job Number

Job # - 51141001
Title – Maintenance of Buildings and Stations Distribution Stations – Baker DS

Job # - 51141002
Title – Maintenance of Buildings and Stations Distribution Stations – Kerman DS

10.2.5 Routine Station Maintenance

10.2.5.1 Introduction

Since 2003 Grimsby Power has been converting 8kV lines from the two substations to 27.6kV. It is anticipated that this work will be completed by the end of 2013 at which time the substations will be taken off line and decommissioned. As this timeframe is imminent no major preventative maintenance will be scheduled for these stations. Items identified during the monthly inspections and with the oil quality tests will be dealt with as required.

10.2.5.2 Retention of Data from Inspections

The data collected from the inspections and maintenance activities will be filed in Engineering in their respective paper folders.

10.2.5.3 Responsibility

Administration of Program Line Superintendent
Administration of Deficiencies Line Superintendent

10.2.5.4 Job Number

Job # - 51141001
Title – Maintenance of Buildings and Stations Distribution Stations – Baker DS

Job # - 51141002
Title – Maintenance of Buildings and Stations Distribution Stations – Kerman DS

10.2.6 Single Phase Hydraulic Recloser Maintenance

10.2.6.1 Introduction

The purpose of the Single Phase Hydraulic Recloser Maintenance Program is to ensure the continued reliability of all single phase recloser devices in the electrical distribution system. Grimsby Power only has reclosers in its Baker DS. Since 2003 Grimsby Power has been converting 8kV lines from the two substations to 27.6kV. It is anticipated that this work will be completed by the end of 2013 at which time the substations will be taken off line and decommissioned. As this timeframe is imminent no major preventative maintenance will be scheduled for these reclosers. Items identified during the monthly inspections will be dealt with as required.

10.2.6.2 Job Number

Job # - 51141001
Title – Maintenance of Buildings and Stations Distribution Stations – Baker DS

10.3 Distribution System Plant Inspections and Ground Level Maintenance

10.3.1 Introduction

Distribution System Plant Inspections are regulated under the OEB Distribution System Code. The code specifies the minimum requirements to inspect urban areas on a 3 year cycle and rural areas on a 6 year cycle.

10.3.2 Status of Program

Established

10.3.3 Definition of Geographic Areas and Frequency of Program:

The areas to be utilized are the same as used in the Line Clearing Tree Trimming Maintenance Program (as described in Section 2.1) and are shown on the attached map (Appendix A).
The timing of each cycle including some completed in the past is as follows in Table C:
TABLE C:

Year	Area# 1	Area #2	Area#3	Area#4	Area#5	Area#6
2004	X	X	X	X	X	X
2005						
2006						
2007	X			X		
2008		X			X	
2009			X			X
2010	X					
2011		X				

2012			X			
2013	X			X		
2014		X			X	
2015			X			X

10.3.4 Specific Work to Be Completed

The specific work to be completed under this program is detailed below. The work involves a visit to each asset location. For overhead distribution plant this means every pole and for underground distribution plant this means all pad mounted equipment and street light poles.

10.3.4.1 Visual Inspection

The visual inspection is to be completed by meeting the minimum requirements of the Distribution System Code – Appendix C– Minimum Inspection Requirements. The GPI condition of the assets will be documented by completing all required fields in the inspection database form(s). This database is built on Microsoft Access software. A copy of the input form is attached in Appendix G.

10.3.4.2 Number Pole

Date Nails - GPI will provide inspection date nails which are to be nailed to the pole at eye level.

10.3.4.3 Identification Sign

GPI public warning signs are to be nailed or screwed to the pole at approximately 6 ft high where one has not already been installed. Identification of MicroFIT and FIT customers (ie – generators) once a standard sign has been developed. Signs are replaced as necessary.

10.3.4.4 Wood Pole Integrity Tests

Wood pole integrity tests are to be performed on poles where the strength of the pole is questionable. GPI has determined that wood boring (1/2" bit) is the most effective way to establish the condition of the pole at or just below grade where most of the decay occurs.

10.3.4.5 Ground Level Repair of Defects

It has been our experience that ground level repairs can be effectively corrected during the inspection process. The contractor may make any of the following repairs as required while on site:

- Replace guy guard
- Bore pole and report findings

10.3.4.6 Remedial Actions to Correct Defects

This program will identify items in the field which will require replacement, repair, or alteration. See "Responsibility" below to identify the person responsible for this remedial action.

10.3.4.7 Responsibility

Administration of Program	Director of Engineering
Correction of Defects – Without I/O	Line Superintendent

Correction of Defects – With I/O Director of Engineering

10.3.4.8 Job Number

Job # - 51200000
Title – Maintenance of Poles Towers and Fixtures

10.4 Off Road High Voltage Line Inspections & Maintenance

10.4.1 Introduction – Off Road Primary

Within the boundaries of Grimsby a number of line sections are off road and inaccessible by truck for parts of the year or at any time. All of these line sections are overhead and are located on a railway right of way and private land. Inspection & maintenance of these lines is necessary on a regular basis to safeguard the reliability of the electrical supply.

10.4.2 Location of Specific Line Sections:

Grimsby Power only has one off road line – From Kelson Rd. going east following the CNR and Hydro One right of way. To our Eastern boundary with NPEI between Durham Road and Bartlett Road. There are approximately 200 poles in this line. This line has been broken down into 12 different sections.

i. Frequency and Type of Program

This section is to be patrolled by foot or all terrain vehicle once per year.
This section is to be inspected approximately once every ten years.

10.4.3 Cycles

The inspection program will be initiated in 2012 as follows in Table D:

TABLE D:

	Line Section											
Year	1	2	3	4	5	6	7	8	9	10	11	12
2012	X	X	X	X	X	X						
2013							X	X	X	X	X	X
2023	X	X	X	X	X	X						
2025							X	X	X	X	X	X

10.4.4 Description of Program

10.4.4.1 Patrol

A patrol consists of a visual inspection of each pole and components from the ground below the pole. Defects are noted and corrective actions put in place by Operations and/or Engineering. Field condition reports are used for reporting actions required. Information about the inspection is noted in the pole inspection database. The inspection form for "Annual Patrol – Off Road Primary" is attached as Appendix B.

10.4.4.2 Status of Program

Implementation

10.4.4.3 Inspection & Maintenance

An inspection consists of a hands on inspection of the pole and components to identify defective equipment. The inspection is to be a close inspection using a track mounted aerial device if required for access. Minor repairs are to be made on the spot – such as reframing, changing insulators, replacing guy wires, etc. Defects and actions taken are noted on the Instruction order documents and input into the pole inspection database.

A detailed Section by Section Procedure is available to facilitate the work.

10.4.4.4 Responsibility

Administration of Program	Line Superintendent
On the Spot Corrections	Line Crew
Correction of Defects – Without I/O	Line Superintendent
Correction of Defects – With I/O	Director of Engineering

10.4.4.5 Job Number

Job # - 51200000
Title – Maintenance of Poles Towers and Fixtures

Job # - 5125000
Title – Maintenance of Overhead Conductors and Devices

Note – Regular job numbers are used to replace equipment.

10.5 Thermography Inspection Program

10.5.1 Introduction

Infrared thermography has proven to be an excellent tool to identify poor electrical connections and overloaded equipment on the distribution system. The purpose of the Thermography Inspection Program is to identify any issues and remediate them as quickly as possible to ensure continuous operation of the distribution system.

In recent years Grimsby Power's distribution reliability has been excellent and as such thermography is not used on a regular basis. There are currently no plans to perform this type of inspection on the distribution system. However, if warranted by reliability concerns an inspection program could be implemented.

10.6 Switch Maintenance Program

10.6.1 Introduction

The purpose of the Switch Maintenance Program is to ensure the continued reliability of all switching devices in the electrical distribution system. The goal of the program will be to maintain all switches on a five year rotational basis. This program consists of physically cleaning, lubricating, and ensuring the switch operates smoothly. This program applies to three phase gang operated switches only (pole and pad-mounted).

There are approximately 80 overhead three phase gang operated switches and 14 pad-mounted switching cubicles installed on the system (2011 statistics).

10.6.2 Overhead Switches

10.6.2.1 Status of Program

Implementation

10.6.2.2 Frequency of Program

Approximately 16 overhead three phase gang operated switches will be maintained in each year of a 5 year cycle.

Approximately 9 switches will be incorporated into the maintenance program with the Off Road Maintenance Program. Six (4) in 2012 and the others in 2013.

10.6.2.3 Specifics of Program

Grimsby Power Inc. has standardized on S&C switches and the inspection and maintenance instructions are listed in Appendix C.

For each switch an "Overhead Switch Maintenance form will be completed. See Appendix B.

10.6.2.4 Retention of Data from Inspections

The data collected from the inspections and maintenance activities will be filed in Engineering in their respective paper folders.
In the future an MS Access database or Asset Management Software Program will be utilized to store this data.

10.6.2.5 Responsibility

Administration of Program Line Superintendent
Schedule and Complete Work Line Superintendent

10.6.2.6 Job Number

Job # - 51250000
Title – Maintenance of Overhead Conductor and Devices

10.6.3 Pad-Mounted Switches

10.6.3.1 Status of Program

Implementation

10.6.3.2 Frequency of Program

Approximately 10 pad mounted switching cubicles will be maintained in each year of a 3 year cycle.

10.6.3.3 Specifics of Program

GPI pad-mounted switches are all manufactured by either S & C Electric.or G&W Inspection and maintenance instructions are as follows:

- S&C Manual PMH Pad-Mounted Gear – (Outdoor Distribution (14.4 kV and 25 kV) – Inspection Recommendations – Instruction Sheet 662-590.
- Letter from S& C – RE - LOAD INTERRUPTER MAINTENANCE-dated Dec. 2 2003

- G&W Electric Company –Manually Operated Vacuum Interrupter- Padmount SF6 Switches . Inspection and maintenance - Instruction Sheet GWI 527-10

See Appendix C & D for listing of S&C's and G&W manufacturer's information.

For each switch a "Pad-Mounted Switch Maintenance" form will be completed. See Appendix B - Forms.

10.6.3.4 Retention of Data from Inspections

The data collected from the inspections and maintenance activities will be filed in Engineering in their respective paper folders.
In the future an MS Access database or Asset Management Software Program will be utilized to store this data.

10.6.3.5 Responsibility

Administration of Program	Line Superintendent
Schedule and Complete Work	Line Superintendent

10.6.3.6 Job Number

Job # - 51500000
Title – Maintenance of Underground Conductors and Devices

10.6.4 Underground Switching Cabinets

10.6.4.1 Status of Program

Implementation

10.6.4.2 Frequency of Program

There are 28 underground cabinets installed in the distribution system. These cabinets contain cable elbows and junctions which tie various sections of cable together. Approximately 4 underground cabinets will be inspected and maintained in each year of a 7 year cycle.

10.6.4.3 Specifics of Program

GPI underground cabinets are all manufactured by The Durham Company. After a period of time the cable elbows are susceptible to degradation causing the elbow and junction to fuse together. In addition to this the junctions corrode causing the attachment to the cabinet to fail.

If these conditions exist cable switching cannot take place. Inspection and maintenance instructions are as follows:

- Cabinet is to be inspected for rust and any metal fatigue
- Operation of elbows is to be checked
- Remove and re-install elbows and junctions as required

For each cubicle an “Underground Cabinet” form will be completed. See Appendix B - Forms.

10.6.4.4 Retention of Data from Inspections

The data collected from the inspections and maintenance activities will be filed in Engineering in their respective paper folders.
In the future an MS Access database or Asset Management Software Program will be utilized to store this data.

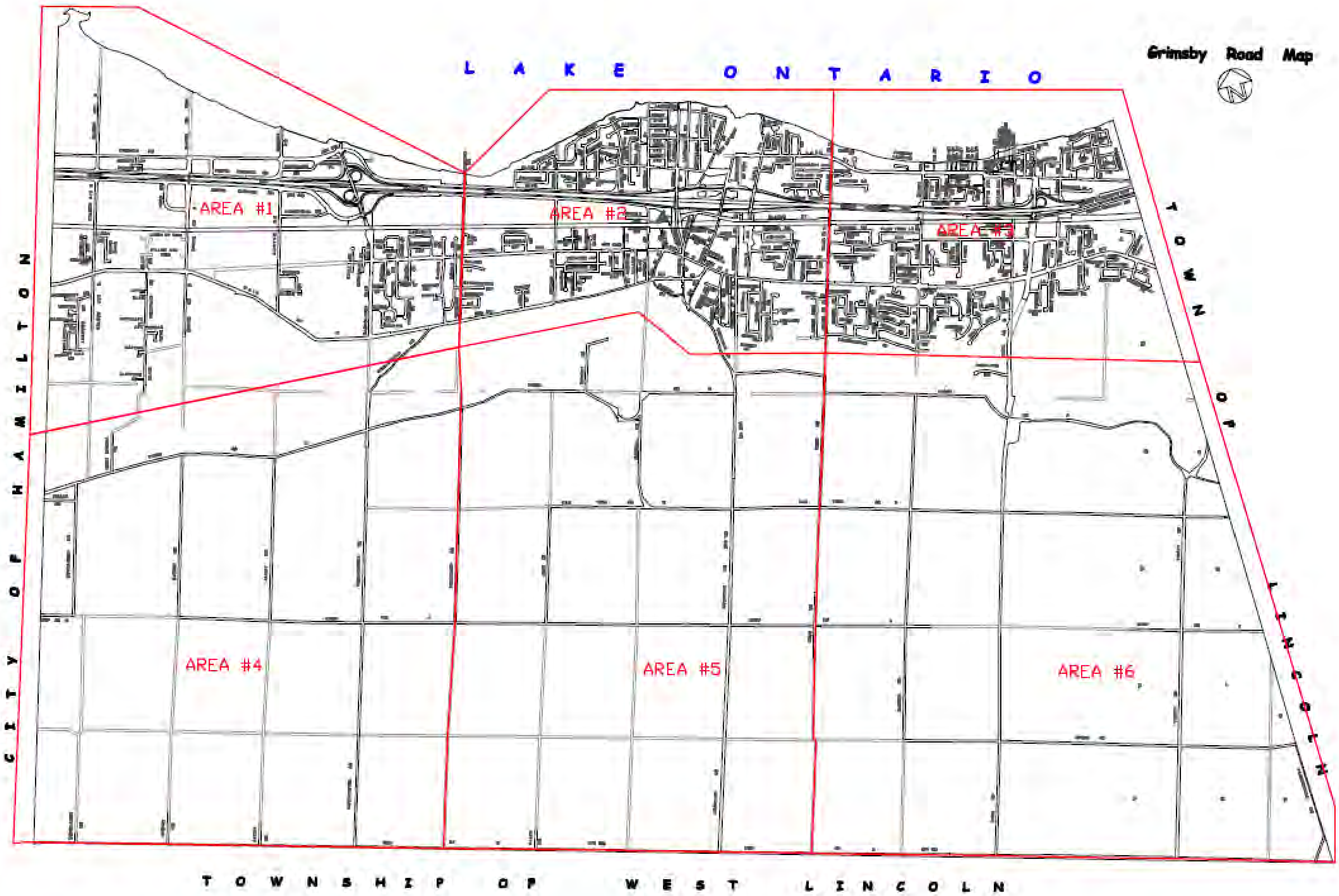
10.6.4.5 Responsibility

Administration of Program Line Superintendent
Schedule and Complete Work Line Superintendent

10.6.4.6 Job Number

Job # - 51500000
Title – Maintenance of Underground Conductors and Devices

Appendix A - Map - Geographic Areas for Distribution System Maintenance & Inspection


Grimsby Road Map
N
L A K E O N T A R I O
AREA #1
AREA #2
AREA #3
AREA #4
AREA #5
AREA #6
C I T Y O F H A M I L T O N
T O W N O F L I N C O L N
T O W N S H I P O F W E S T L I N C O L N

Appendix B – Maintenance Forms

- Overhead Switch Maintenance
- Pad-Mounted Switch Maintenance
- Distribution Station Maintenance
- Distribution Station Monthly Inspection – Specific to Station
- Annual Patrol – Off Road Primary
- Underground Cabinets

Appendix C – S&C Reference Material

Reference # 1 - S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Inspection Recommendations – Instruction Sheet 662-590

Reference #2 – S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Specifications - Specification Bulletin 662A-31

Reference # 3 - S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Instructions for Installation - Instruction Sheet 662-505

Reference # 4 - S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Instructions for Operation - Instruction Sheet 662-510

Reference # 5 - S&C Manual PMH Pad-Mounted Gear (Outdoor Distribution (14.4 kV and 25 kV) – Descriptive Bulletin 662-30

Reference # 6 - S&C Manual Metal-Enclosed Switchgear (Indoor and Outdoor Distribution (4.16 kV through 34.5 kV)) – Inspection Recommendations – Data Bulletin 620-95

Reference #7 – S&C Alduti-Rupter Switches – Outdoor Distribution (14.4kV through 69kV) – Descriptive Bulletin

Reference #8 – S&C Alduti-Rupter Switches – Outdoor Distribution (14.4kV through 46kV) – Specification Bulletin – 761-31

Reference #9 – S&C Alduti-Rupter Switches – Outdoor Distribution – Addendum to Instruction Sheets 761-5XX – 761-31 – Instruction Sheet 761-500A

Reference #10 – S&C Alduti-Rupter Switches – Outdoor Distribution – Three-Pole Double-Break Style Rotating Operating Mechanism – 35.5kV and 47kV – Instructions for Installation and Operation - Instruction Sheet 761-500

Reference #11 – S&C Alduti-Rupter Switches – Outdoor Distribution – Three-Pole Vertical-Break Integer Style Tiered-Outboard Mounting Configuration – 25/34.5kV and 34.5kV – Instructions for Installation - Instruction Sheet 761-530 – GPI Stock Code 681910

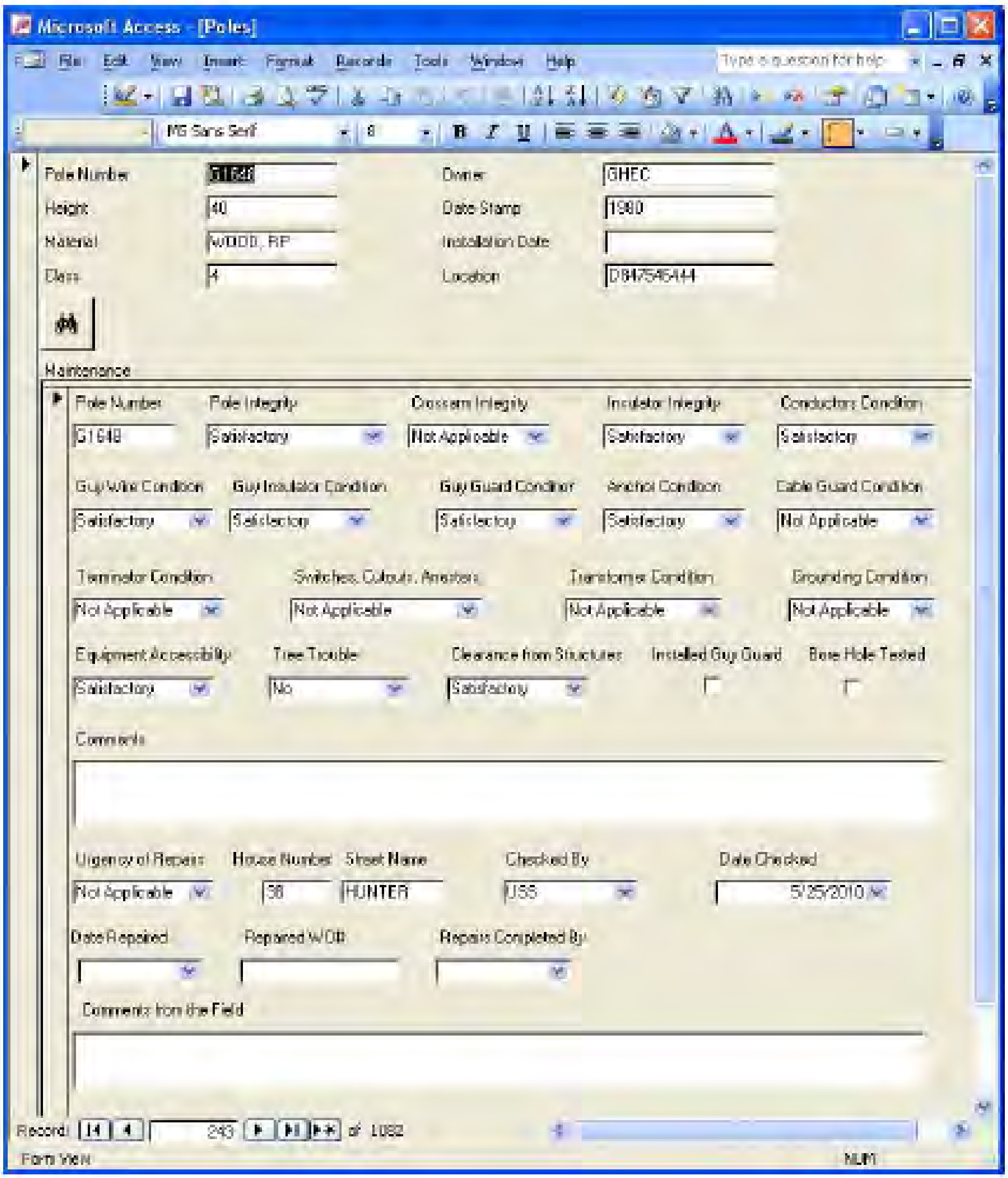
Reference #12 – S&C Alduti-Rupter Switches – Outdoor Distribution – Three-Pole Side-Break Integer Style Rotating Operating Mechanism – 25/34.5kV and 34.5kV – Instructions for Installation and Operation- Instruction Sheet 761-580 – GPI Stock Code 681905

Reference #13 – S&C Alduti-Rupter Switches – Outdoor Distribution – Three-Pole Vertical-Break Integer Style – 25/34.5kV and 34.5kV – Instructions for Installation - Instruction Sheet 761-535 – GPI Stock Code 681900

Appendix D – G&W Reference Material

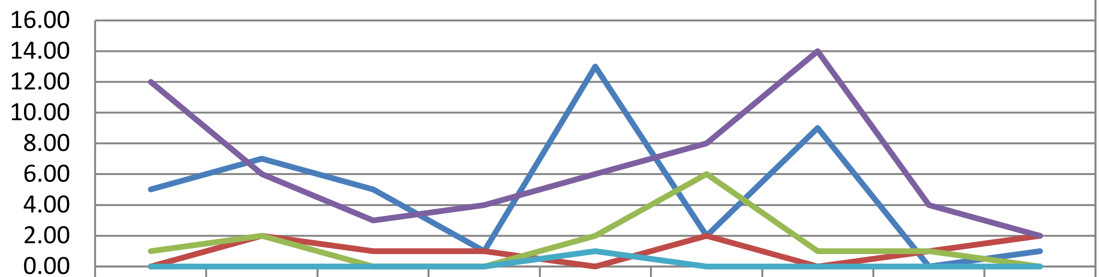
Reference # 1 - G&W Electric Company –Manually Operated Vacuum Interrupter- Padmount SF6 Switches . Inspection and Maintenance - Instruction Sheet GWI 527-10

Appendix G – Sample of GPI Inspection Report



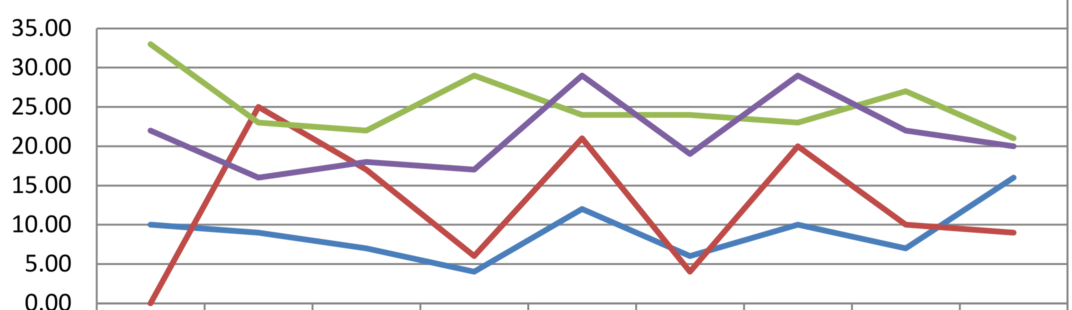
Appendix D - Outages by Cause

GPI Outage Causes by Year



	2002	2003	2004	2005	2006	2007	2008	2009	2010
Unknown	5	7	5	1	13	2	9	0	1
Scheduled Outage	0	2	1	1	0	2	0	1	2
Loss of Supply	1	2	0	0	2	6	1	1	0
Adverse Weather	12	6	3	4	6	8	14	4	2
Human Element	0	0	0	0	1	0	0	0	0

GPI Outage Causes by Year



	2002	2003	2004	2005	2006	2007	2008	2009	2010
Tree Contacts	10	9	7	4	12	6	10	7	16
Lightning	0	25	17	6	21	4	20	10	9
Defective Equipment	33	23	22	29	24	24	23	27	21
Foreign Interference	22	16	18	17	29	19	29	22	20

Appendix E – Discretionary Capital Projects for 2011

GPI's remaining distribution stations (Kerman and Baker) have been in place for many years and are approaching end of life. GPI's distribution planning strategy has been to eliminate these stations by upgrading the 8kv distribution system to 27kv. Continuing with past efforts the following projects are slated for 2011:

Project Name - Elm Tree Road West Voltage Conversion (Mountain Rd. to Allen Rd.)

- Estimated 30 new poles to be installed to replace existing poles.
- Estimated 5 new transformers to be installed to replace existing transformers
- Install new 3/0 ACSR primary conductor 2 km for 1-phase and 2 km for neutral
- Budgeted cost for above mentioned project is $126,588

Project Name - Elm Tree Road East Voltage Conversion (Park Road to Thirty Road, from step-down transformer #6351 to open Switch C237R down to Switch #C229W)

- Estimated 100 new poles to be installed to replace existing poles.
- Estimated 23 new transformers to be installed to replace existing transformers
- Install new 3/0 ACSR primary conductor 5.5 km for 1-phase and 5.5 km for neutral
- Budgeted cost for above mentioned project is $420,418

Project Name - Ridge Road East Voltage Conversion (Park Rd. to Thirty Rd., from step-down transformer # 6350 to open Switch # C237R)

- Estimated 50 new poles to be installed to replace existing poles.
- Estimated 14 New transformers to be installed to replace existing transformers
- Transfer existing 3/0 ACSR primary conductor to new poles
- Budgeted cost for above mentioned project is $214,989

Project Name – Pad Mounted Transformer Maintenance Program

- Replacement of 10 pad mounted transformers that yearly inspection reveals warranted replacement usually due to excessive corrosion.
- Budgeted cost for above mentioned project is $99,922

Project Name – Silicon Injection of Primary Underground Cables

- Cable rejuvenation by silicon injection of approximately 2500 meters of primary cables that reached or about to reach their typical useful life.
- Budgeted cost for the above mentioned project is $115,023

Appendix F – Discretionary Capital Projects for 2012

GPI's remaining distribution stations (Kerman and Baker) have been in place for many years and are approaching end of life. GPI's distribution planning strategy has been to eliminate these stations by upgrading the 8kv distribution system to 27kv. Continuing with past efforts the following projects are slated for 2012:

Project Name – Sobie Road Voltage Conversion (from step-down transformer #6352 to Fairbrother Rd, along Thirty Rd. from switch# C229W to Mud St.)

- Estimated 45 new poles to be installed to replace existing poles.
- Estimated 11 New transformers to be installed to replace existing transformers
- Install new 3/0 ACSR primary conductor 3 km for 1-phase and 3 km for neutral
- Budgeted cost for above mentioned project is $126,588

Project Name – Woolverton Road Voltage Conversion (from Ridge Rd. West to Main St.)

- Estimated 16 new poles to be installed to replace existing poles.
- Installation of 2 guy less concrete poles
- Estimated 3 New transformers to be installed to replace existing transformers
- Install new 556 MCM primary conductor 3 phases for 1.1km
- Budgeted cost for above mentioned project is $200,121

Project Name - Ridge Road East between Mountain Rd. and Park-Part#1 Voltage Conversion (Mountain Rd. to Russ Rd.)

- Estimated 15 new poles to be installed to replace existing poles.
- Estimated 2 New transformers to be installed to replace existing transformers
- Install new neutral conductor and lower secondary buss
- Budgeted cost for above mentioned project is $65,963

Project Name - Ridge Road East between Mountain Rd. and Park-Part#2 Voltage Conversion (Russ Rd. to Park Rd.)

- Estimated 11 new poles to be installed to replace existing poles.

- Estimated 1 new transformers to be installed to replace existing transformer
- Install new neutral conductor and lower secondary buss
- Budgeted cost for above mentioned project is $50,079

Project Name – Maple Avenue Voltage Conversion (CNR Tracks to Main St. East)

- Estimated 7 new poles to be installed to replace existing poles.
- Estimated 2 new transformers to be installed to replace existing transformers
- Install new neutral conductor
- Install new 266 secondary buss
- Budgeted cost for above mentioned project is $61,265

Project Name – Pad Mounted Transformer Maintenance Program

- Replacement of 10 pad mounted transformers that yearly inspection reveals warranted replacement usually due to excessive corrosion.
- Budgeted cost for above mentioned project is $107,781

Project Name – Silicon Injection of Primary Underground Cables

- Cable rejuvenation by silicon injection of approximately 2500 meters of primary cables that reached or about to reach their typical useful life.
- Budgeted cost for the above mentioned project is $120,076

Exhibit 3 Operating Revenue

OVERVIEW

This Exhibit provides the details of Grimsby Power Inc.'s operating revenue for 2006 Board Approved, 2006 Actual, 2008 Actual, 2009 Actual, 2010 Actual, the 2011 Bridge Year and the 2012 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

Grimsby Power Inc. is proposing a total Service Revenue Requirement of $4,583,444 for the 2012 Test Year. This amount includes a Base Revenue Requirement of $4,243,703 plus revenue offsets of $339,741 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3.1 and provides a comparison of total revenues from the 2006 OEB approved year to the 2012 Test Year.

Table 3.1 Summary of Operating Revenue

SUMMARY OF OPERATING REVENUE TABLE									
Summary of Operating	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test at Current Rates	2012 Test at Proposed rates
Revenue	$	$	$	$	$	$		$	$
Distribution Revenue									
Residential	2,288,126	2,295,686	2,384,473	2,427,790	2,436,326	2,482,572	2,547,789	2,555,823	3,141,137
GS<50	399,613	362,401	389,142	385,108	386,847	393,977	390,000	392,621	492,337
GS>50	480,916	453,153	465,849	473,755	472,059	457,847	455,000	465,269	542,054
Streetlight	17,381	33,270	33,953	34,488	32,293	34,077	34,000	34,428	80,351
Unmetered Scattered Load	33,763	28,879	24,020	18,929	16,570	16,121	15,500	15,786	20,824
Less: Transformer credit	(24,294)	(38,775)	(42,544)	(41,865)	(56,426)	(33,020)	(33,000)	(33,000)	(33,000)
Total	3,195,505	3,134,614	3,254,893	3,298,205	3,287,668	3,351,574	3,409,289	3,430,927	4,243,703
% of Total Revenue	90.7%	90.4%	89.0%	88.7%	89.6%	90.7%	91.1%	91.0%	92.6%
Other Distribution Revenue									
SSS Administration Revenue	27,592	25,172	24,769	25,372	25,805	26,200	26,200	26,750	26,750
Late Payment Charges	14,073	43,631	59,851	56,481	58,427	53,582	55,000	55,000	55,000
Specific Service Charges	103,981	33,206	34,494	34,543	66,027	59,351	54,800	54,800	54,800
MicroFIT Revenue	-	-	-	-	-	26	200	200	200
Other Distribution Revenue	63,063	91,090	83,268	83,537	86,028	84,125	86,900	91,391	91,391
Other Income & Expenses	119,051	139,370	200,029	218,526	144,135	122,004	108,600	111,600	111,600
Subtotal	300,168	307,297	377,642	393,087	354,617	319,089	305,500	312,991	312,991
Total	327,760	332,469	402,411	418,459	380,422	345,288	331,700	339,741	339,741
% of Total Revenue	9.3%	9.6%	11.0%	11.3%	10.4%	9.3%	8.9%	9.0%	7.4%
Grand Total	3,523,265	3,467,083	3,657,304	3,716,664	3,668,091	3,696,862	3,740,989	3,770,668	4,583,444
Variance from 2006 Board Approved		-1.59%	3.80%	5.49%	4.11%	4.93%	6.18%	7.02%	30.09%
Variance from Prior Year			5.49%	1.62%	-1.31%	0.78%	1.19%	0.79%	21.56%

Throughput Revenue

Overall load reductions from 2007 to the 2012 forecast amounts can be attributed to two major factors - seasonal weather conditions, and the success of conservation initiatives undertaken by Grimsby Power Customers. As illustrated in Table 3.3 of this exhibit, average consumption per customer for most customers (Residential and GS<50 Class) has steadily declined.

Information related to Grimsby Power Inc.'s throughput revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year, CDM adjustments and known economic conditions.

A detailed variance analysis on the throughput revenue is set further in this exhibit.

Other Revenue

Other revenues include Standard Service Supply (SSS) Administration Charges, Retail Service Revenues, Service Transaction Requests Revenues Rent form Electricity Property, Late Payment Charges, Specific Service Charges, Revenues from Merchandise, Jobbing, Gain on Disposition of Utility, Revenues/Expenses of Non-Utility Operations, Miscellaneous Non-Operating Income and Interest Income. The dividend payments as well as the fall in bank interest rates had a significant impact on other revenue as interest income declined.

A detailed variance analysis on other revenue is set out further in this exhibit.

LOAD AND REVENUE FORECASTS

Overview – Weather Normalized Load and Customer/Connection Forecast

The purpose of this evidence is to present the process used by Grimsby Power Inc. to prepare the weather normalized load and customer/connection forecast used to design the proposed 2012 electricity distribution rates.

In summary, Grimsby Power Inc. has used the same regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, Grimsby Power Inc. submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. Grimsby Power Inc. has the data for the amount of electricity (in kWh) purchased from the IESO for use by Grimsby Power Inc.'s customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for Grimsby Power Inc. for the Bridge Year and the Test Year which is converted to bill kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During proceedings related to the 2009 and 2010 cost of service applications for a number of other distributors, interveners expressed concerns with the load forecasting process that was proposed at the time by those distributors. For the 2009 cost of service applications, interveners suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly billed kWh by rate class. Grimsby Power Inc. submits that conducting a regression analysis which relates the monthly billed kWh of a class to other monthly variables is problematic. The monthly billed amount does not reflect the amount consumed in the month. Rather, it reflects the amount billed. The amount billed is based on billing cycle meter reading schedules whose reading dates vary and typically are not at month end. The amount billed could include consumption from the prior month or even earlier. Using a regression analysis to relate rate class billing data to a variable such as heating degree days does not appear to be reasonable, since the resulting regression model would attempt to relate heating degree days in a month to the amount billed in the month, not the amount consumed. In Grimsby Power Inc.'s view, variables such as heating degree days impact the amount consumed and not the amount billed. It is possible to estimate the amount consumed in a month based on the amount billed, but until smart meters are fully deployed this would only be an estimate. This would reduce the accuracy of a regression model that is based on monthly billing data.

In addition, Grimsby Power Inc. understands that a number of 2010 cost of service applicants attempted to conduct the regression analysis on a rate class basis but were unsuccessful in achieving reasonable results that could be used in the load forecasting process. Conducting the regression analysis on purchases provides better results since a higher level of historical data increases the accuracy of the regression analysis.

Grimsby Power Inc. understands that to a certain degree the process of developing a load forecast for a cost of service rate application is an evolving science for electricity distributors in the province. During the review of 2010 cost of service applications, Board staff and interveners expressed concern that the regression analysis assigned coefficients to some variables that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management ("CDM") savings in the utility but in the view of Board staff and interveners this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. Grimsby Power Inc. has attempted to address these concerns in the load forecast used in this Application. However, Grimsby Power Inc. expects to include additional improvements to the load forecasting methodology in future cost of service rate applications by: i) taking into consideration data provided by smart meters; and ii) evaluating how others will conduct load forecasts in future cost of service rate applications. Based on the OEB's approval of this methodology in a number of previous cost of service applications, and based on the discussion that follows, Grimsby Power Inc. submits that its load forecasting methodology is reasonable at this time for the purposes of this Application.

The following Tables (3.2 through to 3.4) provide the data to support the weather normalized load forecast used by Grimsby Power Inc. in this Application.

Table 3.2 Summary of Load and Customer/Connection Forecast

Summary of Load and Customer/Connection Forecast						
Year	**Billed (kWh)**	**Growth (kWh)**	**Percent Charge**	**Customer/ Connection Count**	**Growth**	**Percent Charge %**
Billed Energy (kWh) and Customer Count/Connections						
2006 Board Approved	161,637,489			11,915		
2003 Actual	157,104,641			11,184		
2004 Actual	157,313,949	209,307.89	0.13%	11,641	457	4.09%
2005 Actual	171,012,428	13,698,479.05	8.71%	11,921	279	2.40%
2006 Actual	169,025,475	(1,986,952.30)	-1.16%	12,046	125	1.05%
2007 Actual	173,068,981	4,043,505.31	2.39%	12,161	116	0.96%
2008 Actual	172,075,839	(993,141.63)	-0.57%	12,382	221	1.81%
2009 Actual	170,620,093	(1,455,745.85)	-0.85%	12,477	95	0.77%
2010 Actual	179,605,826	8,985,732.53	5.27%	12,654	177	1.42%
2011 Normalized Bridge	179,765,505	159,678.93	0.09%	12,882	228	1.80%
2012 Normalized Test	181,732,931	1,967,426.30	1.09%	13,114	233	1.81%

Notes:

- 2003 to 2010 are weather actual, while 2011 and 2012 are weather normalized. Grimsby Power Inc. does not have a thorough process to adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

- Total Customers/Connections are on an average annual basis and streetlight and unmetered loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers are shown in Table 3.3 and Table 3.4 shows the average usage per customer on a rate class basis.

Table 3.3 Billed Energy and Number of Customer/Connection Forecast by Rate Class

Billed Energy and Number of Customer/Connection Forecast by Rate class						
Year	**Residential**	**General Service < 50**	**General Service > 50**	**Streetlights**	**USL**	**Total**
Billed Energy (kWh)						
2006 Board Approved	87,224,776	18,430,695	53,991,726	1,576,635	413,657	161,637,489
2003 Actual	80,050,770	18,395,078	56,599,645	1,554,990	504,158	157,104,641
2004 Actual	80,274,538	17,788,869	57,243,738	1,602,138	404,665	157,313,949
2005 Actual	89,524,367	18,053,236	61,428,168	1,608,063	398,594	171,012,428
2006 Actual	85,590,832	17,886,710	63,517,727	1,602,773	427,433	169,025,475
2007 Actual	86,770,665	18,502,908	65,799,685	1,584,019	411,704	173,068,981
2008 Actual	86,978,306	18,161,547	64,972,194	1,611,475	352,317	172,075,839
2009 Actual	86,819,996	18,343,495	63,520,024	1,560,091	376,487	170,620,093
2010 Actual	91,844,703	18,780,136	67,026,092	1,572,970	381,924	179,605,826
2011 Normalized Bridge	**91,699,965**	**18,440,477**	**67,681,139**	**1,575,556**	**368,368**	**179,765,505**
2012 Normalized Test	**92,606,843**	**18,314,894**	**68,877,755**	**1,578,145**	**355,293**	**181,732,931**

Number of Customers/Connections						
2006 Board Approved	8,535	706	115	2,477	82	11,915
2003 Actual	7,979	623	110	2,391	82	11,184
2004 Actual	8,368	623	114	2,454	82	11,641
2005 Actual	8,606	629	115	2,489	82	11,921
2006 Actual	8,715	639	114	2,493	85	12,046
2007 Actual	8,825	657	102	2,493	84	12,161
2008 Actual	9,007	656	105	2,529	85	12,382
2009 Actual	9,147	662	100	2,486	82	12,477
2010 Actual	9,290	669	102	2,512	80	12,654
2011 Normalized Bridge	**9,495**	**676**	**101**	**2,530**	**80**	**12,882**
2012 Normalized Test	**9,703**	**683**	**100**	**2,548**	**80**	**13,114**

Table 3.4 Annual Usage per Customer by Rate Class

Annual usage per Customer/Connection Forecast by Rate class					
Year	Residential	General Service < 50	General Service > 50	Streetlights	USL
Energy Usage per Customer/Connection(kWh per customer/connection)					
2006 Board Approved	10,220	26,106	469,493	637	5,045
2003 Actual	10,033	29,538	513,764	650	6,148
2004 Actual	9,593	28,534	501,771	653	4,935
2005 Actual	10,403	28,694	535,711	646	4,861
2006 Actual	9,821	27,999	559,628	643	5,029
2007 Actual	9,832	28,181	642,470	635	4,901
2008 Actual	9,657	27,682	620,260	637	4,145
2009 Actual	9,492	27,702	636,261	628	4,591
2010 Actual	9,886	28,068	654,978	626	4,774
2011 Normalized Bridge	**9,658**	**27,280**	**668,385**	**623**	**4,605**
2012 Normalized Test	**9,544**	**26,818**	**687,407**	**619**	**4,441**
Annual Growth Rate in Usage per Customers/Connections					
2006 Board Approved vs 2006 Actual	4.1%	-6.8%	-16.1%	-1.0%	0.3%
2003 Actual					
2004 Actual	-4.4%	-3.4%	-2.3%	0.4%	-19.7%
2005 Actual	8.4%	0.6%	6.8%	-1.0%	-1.5%
2006 Actual	-5.6%	-2.4%	4.5%	-0.5%	3.5%
2007 Actual	0.1%	0.6%	14.8%	-1.2%	-2.5%
2008 Actual	-1.8%	-1.8%	-3.5%	0.3%	-15.4%
2009 Actual	-1.7%	0.1%	2.6%	-1.5%	10.8%
2010 Actual	4.2%	1.3%	2.9%	-0.2%	4.0%
2011 Normalized Bridge	**-2.3%**	**-2.8%**	**2.0%**	**-0.5%**	**-3.5%**
2012 Normalized Test	**-1.2%**	**-1.7%**	**2.8%**	**-0.5%**	**-3.5%**

LOAD FORECAST AND METHODOLOGY – MULTIVARIATE REGRESSION MODEL

Grimsby Power Inc.'s weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, number of customers, weather, and calendar related events. This regression analysis is run a number of times using different factors. With each run a correlation analysis is also performed. The regression statistical outputs of each analysis and the correlation outputs are analyzed to determine which factors are best suited to Grimsby Power Inc.'s forecast. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchased kWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); calendar variables (days in month, seasonal); and number of customers. The regression model uses monthly kWh and monthly values of independent variables from January 1999 to December 2010 to determine the monthly regression coefficients. This provides 144 monthly data points which represent a reasonable data set for use in a regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard, Grimsby Power Inc. submits that it is appropriate to review the impact of weather since 1999 on the energy usage and then determine the average weather conditions from January 1999 to December 2010 which would be applied in the forecasting process to determine a weather normalized forecast. However, in accordance with the OEB's Filing Requirements, Grimsby Power Inc. has also provided a sensitivity analysis showing the impact on the 2012 forecast of purchases assuming weather normal conditions are based on a 10-year average and a 20-year trend of weather data.

The multifactor regression model has determined drivers of year-over-year changes in Grimsby Power Inc.'s load growth; these include weather, "calendar" factors, and the number of customers. These factors are captured within the multifactor regression model.

The main factors in the regression analysis are as follows:

- The number of customers.
- Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.
- Calendar factors including the number of days in a particular month and a "flag" variable to capture the typically lower usage in the spring and fall months.

Factors that were found to be statistically insignificant or didn't correlate well are as follows:

- Ontario Real Gross Domestic Product ("GDP") index
- Number of peak hours in the month

The CDM factor was not used in the regression analysis. Forecasted CDM results based on Grimsby Power Inc.'s mandated CDM kwh targets have been directly subtracted from the predicted consumption results for the years 2011 and 2012 as follows:

- 2011 – Target of 7,760,000 times 10%
- 2012 – Target of 7,760,000 times 20%

The following outlines the prediction model used by Grimsby Power Inc. to predict weather normal purchases for 2011 and 2012:

Grimsby Power Inc.'s Monthly Predicted kWh Purchases

= Heating Degree Days * 2,920
+ Cooling Degree Days * 36,689
+ Number of Days in the Month * 452,205
+ Spring Fall Flag * (866,250)
+ Number of Customers * 1,281
+ Intercept of (12,588,627)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix 3.1.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from the Hamilton CS Station was used.

b) The calendar provided information related to number of days in the month and the spring/fall flag.

The prediction formula has the following statistical results in Table 3.5:

Table 3.5 Statistical Results of Regression Analysis

Statistical Results

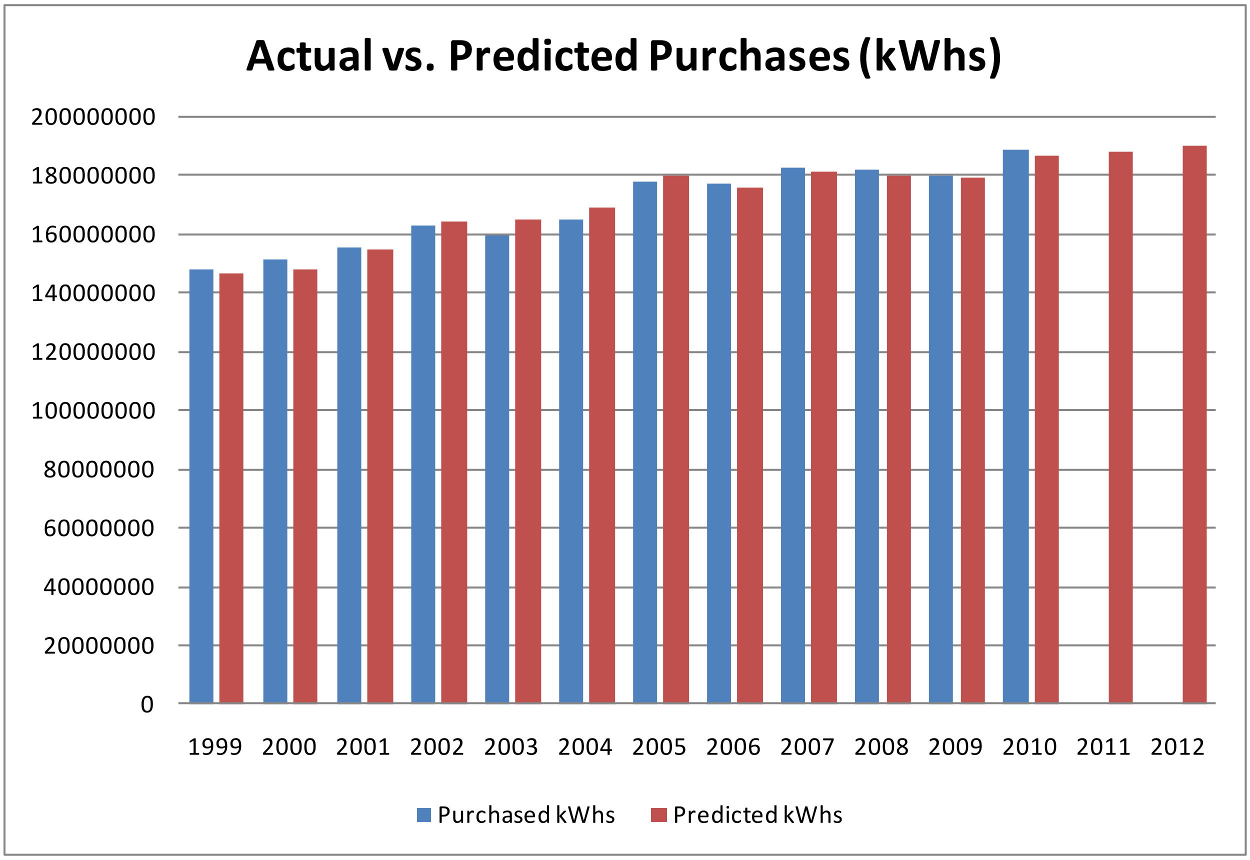
Statistic	Value
R Square	92.2%
Adjusted R Square	91.9%
F-Test	326.1
T-stats by Coefficient	
Intercept	(7.21)
Heating Degree Days	10.14
Cooling Degree Days	16.52
Number of Days in Month	8.04
Spring Fall Flag	(7.12)
Number of Customers	25.36

The annual results of the above prediction formula compared to the actual annual purchases from 1999 to 2010 are reviewed, which are shown in Table 3.6 and Chart 3.1 below, the resulting prediction equation appears to be reasonable.

Table 3.6 Comparison of Actual vs. Predicted kWhs

Year	Purchased kWhs	Predicted kWhs	% Difference
1999	147,636,897	146,555,598	-0.73%
2000	151,402,551	147,802,223	-2.38%
2001	155,743,857	154,573,546	-0.75%
2002	162,988,397	164,222,412	0.76%
2003	159,246,067	164,918,025	3.56%
2004	164,668,533	168,831,873	2.53%
2005	177,744,778	180,087,897	1.32%
2006	177,010,661	176,003,138	-0.57%
2007	182,668,136	181,037,961	-0.89%
2008	181,594,867	179,969,738	-0.89%
2009	179,620,065	179,042,205	-0.32%
2010	188,942,673	186,939,473	-1.06%
2011 Normalized Bridge		188,013,819	
2012 Normalized Test		190,071,518	
2012 Weather Normal - 10 year average		190,553,317	
2012 Weather Normal - 20 year trend		191,039,752	

Chart 3.1 Comparison of Actual vs. Predicted kWhs



In addition, the predicted total system purchases for Grimsby Power Inc. are provided for 2011 and 2012. For 2011 and 2012 the system purchases reflect a weather normalized forecast for the full year.

The weather normalized amount for 2012 is determined by using 2012 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 1999 to December 2010 (i.e. 12 years). The 2012 weather normalized 10 year average value represents the average heating degree days and cooling degree days that occurred from January 2000 to December 2010. The 2012 weather normalized

20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1990 to December 2010.

The weather normal twelve year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The twelve year average has been used as this is consistent with the period of time over which the regression analysis was conducted.

Billed kWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. For the period 1999 to 2010 the average loss factor has been 4.59%. With this average loss factor the total weather normalized billed energy will be 179.8 GWh for 2011 (i.e. 188.0/1.0459) and 181.7 GWh for 2012 (i.e. 190.0/1.0459).

Billed kWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in Table 3.7.

Table 3.7 Historical Customer/Connection Data

Historical Customer/Connection Data						
Year	Residential	General Service < 50	General Service > 50	Streetlights	USL	Total
2003 Actual	7,979	623	110	2,391	82	11,184
2004 Actual	8,368	623	114	2,454	82	11,641
2005 Actual	8,606	629	115	2,489	82	11,921
2006 Actual	8,715	639	114	2,493	85	12,046
2007 Actual	8,825	657	102	2,493	84	12,161
2008 Actual	9,007	656	105	2,529	85	12,382
2009 Actual	9,147	662	100	2,486	82	12,477
2010 Actual	9,290	669	102	2,512	80	12,654
2011 Normalized Bridge	9,495	676	101	2,530	80	12,882
2012 Normalized Test	9,703	683	100	2,548	80	13,114

From the historical customer/connection data the growth rates in customers/connections can be evaluated. The growth rates are provided in Table 3.8. The compound annual growth rate (CAGR) using Excel's geometric mean function (GEOMEAN) is calculated from 2003 to 2010.

Table 3.8 Growth Rate in Customer/Connections

Growth Rate in Customer/Connections					
Year	Residential	General Service < 50	General Service > 50	Streetlights	USL
2003 Actual					
2004 Actual	4.9%	0.1%	3.6%	2.6%	0.0%
2005 Actual	2.8%	0.9%	0.5%	1.4%	0.0%
2006 Actual	1.3%	1.5%	-1.0%	0.2%	3.7%
2007 Actual	1.3%	2.8%	-9.8%	0.0%	-1.2%
2008 Actual	2.1%	-0.1%	2.3%	1.4%	1.2%
2009 Actual	1.6%	0.9%	-4.7%	-1.7%	-3.5%
2010 Actual	1.6%	1.0%	2.5%	1.0%	-2.4%
Geometric Mean	2.2%	1.0%	-1.0%	0.7%	-0.4%

The resulting geometric mean was applied to the 2010 actual customer/connection numbers to determine the forecast of customer/connections in 2011 and 2012.

Grimsby Power Inc. believes the forecast is an accurate representation of what can be expected.

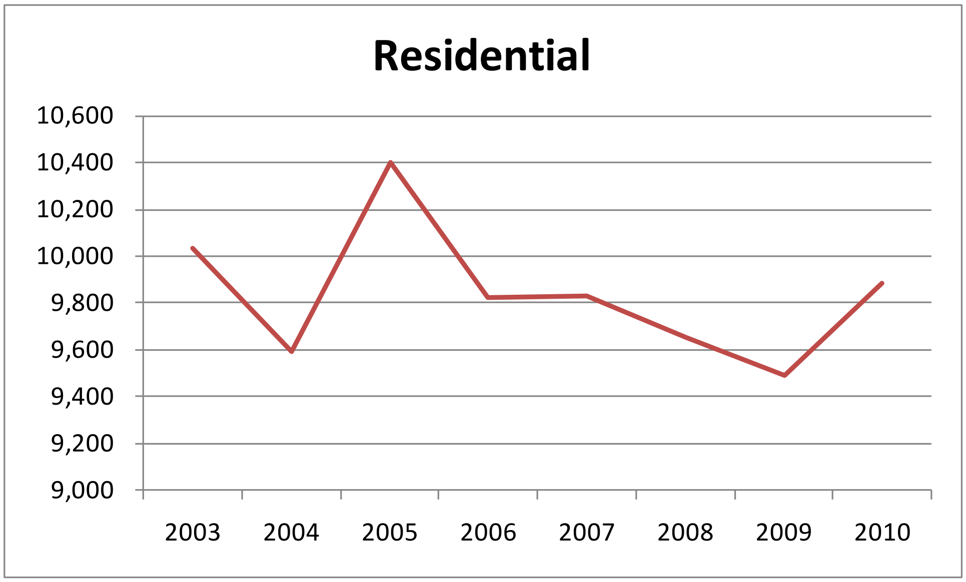
The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. Table 3.9 provides the average annual usage per customer by rate class from 2003 to 2010.

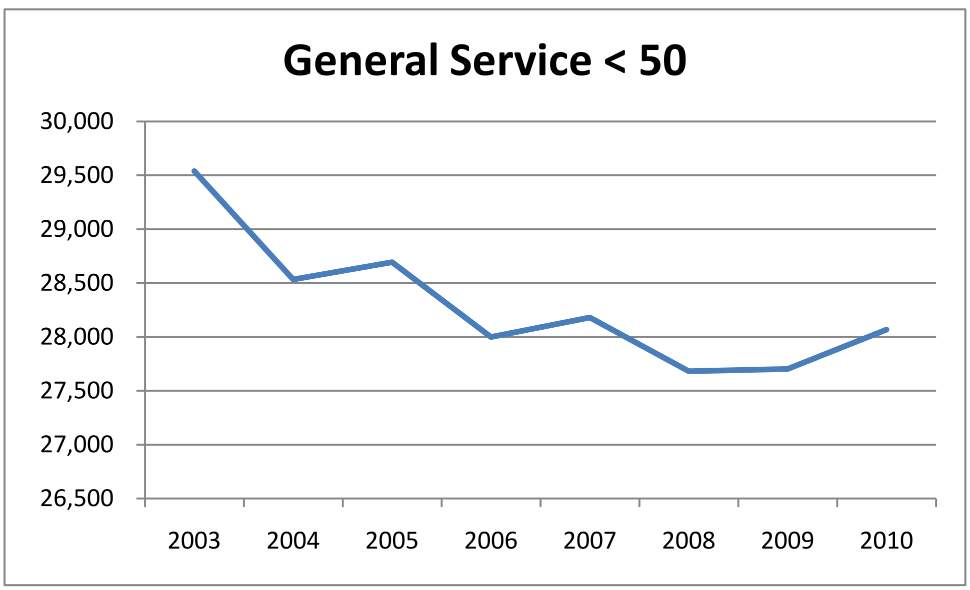
Table 3.9 Historical Annual Usage per Customer

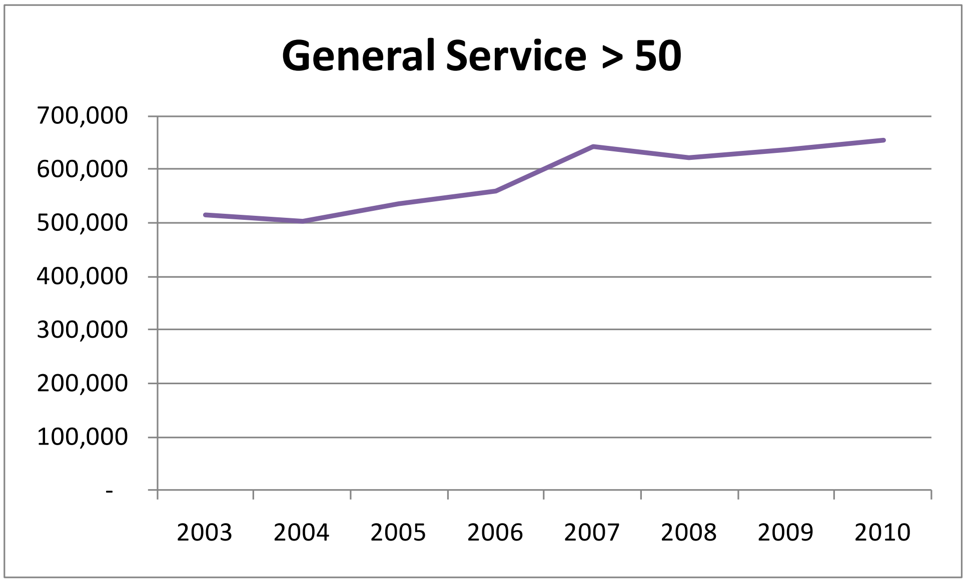
Historical Annual Usage per Customer					
Year	**Residential**	**General Service < 50**	**General Service > 50**	**Streetlights**	**USL**
Energy Usage per Customer/Connection(kWh per customer/connection)					
2003 Actual	10,033	29,538	513,764	650	6,148
2004 Actual	9,593	28,534	501,771	653	4,935
2005 Actual	10,403	28,694	535,711	646	4,861
2006 Actual	9,821	27,999	559,628	643	5,029
2007 Actual	9,832	28,181	642,470	635	4,901
2008 Actual	9,657	27,682	620,260	637	4,145
2009 Actual	9,492	27,702	636,261	628	4,591
2010 Actual	9,886	28,068	654,978	626	4,774

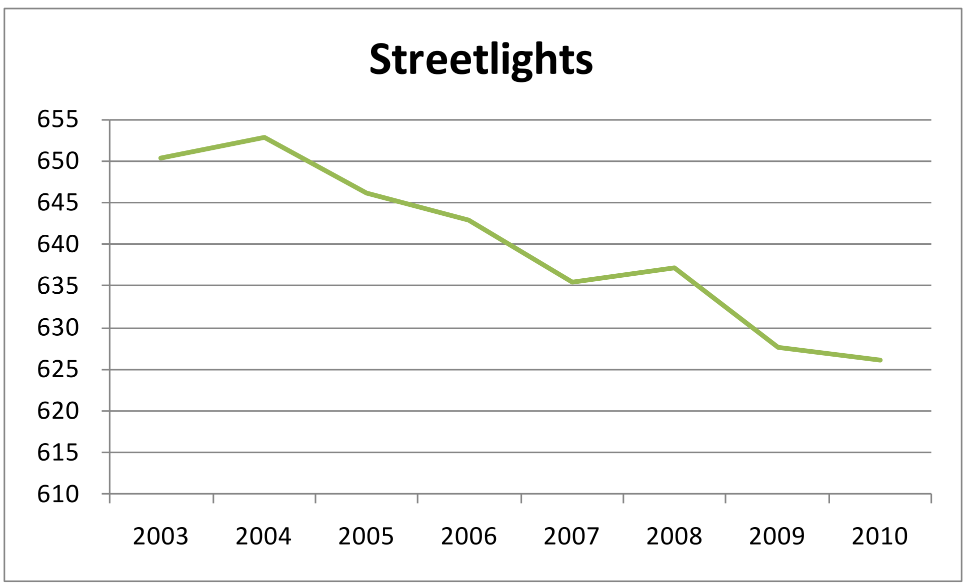
Historical usage shown by customer class is also shown in Chart 3.2 below:

Chart 3.2 Historical Annual Usage per Customer






General Service > 50
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
2003
2004
2005
2006
2007
2008
2009
2010


Streetlights
655
650
645
640
635
630
625
620
615
610
2003
2004
2005
2006
2007
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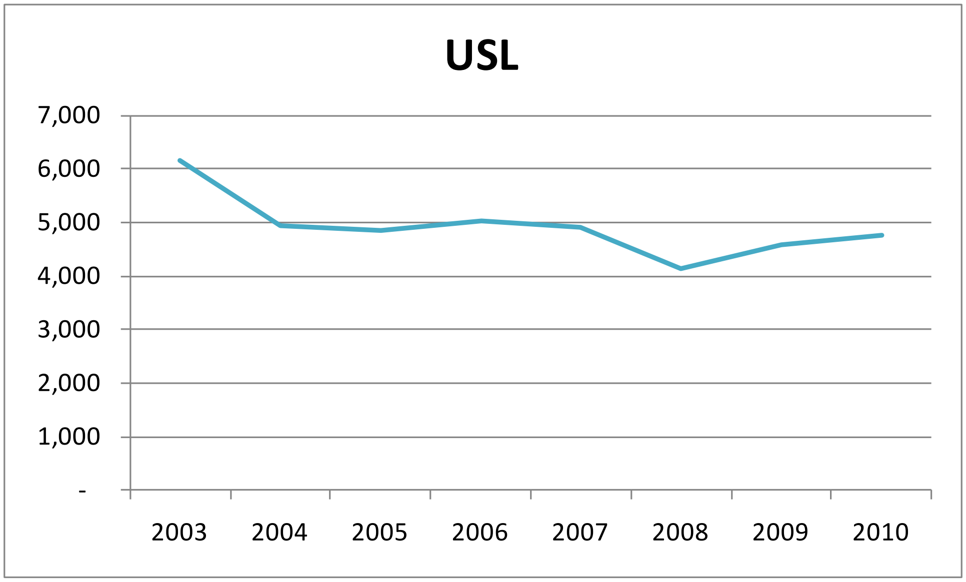
2010



As can been seen in Table 3.9 and Chart 3.2 usage per customer/connection generally declines after 2005. GPI believes that this decline is partially due to the CDM programs initiated in 2006 and onward.

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in Table3.10. The compound annual growth rate (CAGR) using Excel's geometric mean function (GEOMEAN) is calculated from 2003 to 2010.

Table 3.10 Growth Rate in Usage per Customer/Connections

Growth Rate in Usage per Customers/Connections					
Year	Residential	General Service < 50	General Service > 50	Streetlights	USL
Growth Rate in Customers/Connections					
2003 Actual					
2004 Actual	-4.4%	-3.4%	-2.3%	0.4%	-19.7%
2005 Actual	8.4%	0.6%	6.8%	-1.0%	-1.5%
2006 Actual	-5.6%	-2.4%	4.5%	-0.5%	3.5%
2007 Actual	0.1%	0.6%	14.8%	-1.2%	-2.5%
2008 Actual	-1.8%	-1.8%	-3.5%	0.3%	-15.4%
2009 Actual	-1.7%	0.1%	2.6%	-1.5%	10.8%
2010 Actual	4.2%	1.3%	2.9%	-0.2%	4.0%
Geometric Mean	**-0.21%**	**-0.73%**	**3.53%**	**-0.54%**	**-3.55%**

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2010 actual usage and the resulting usage forecast for 2011 and 2012 is as follows:

Table 3.11 Forecast Annual kWh Usage per Customer/Connections

Forecast Annual kWh Usage per Customers/Connections					
Year	Residential	General Service < 50	General Service > 50	Streetlights	USL
Forecast Annual kWh Usage per Customers/Connections					
2011	9,865	27,865	678,099	623	4,605
2012	9,844	27,662	702,036	619	4,441

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3.11 by the forecast of annual usage per customer/connection from Table 3.9. The resulting non-normalized weather billed energy forecast is shown in the following Table.

Table 3.12 Non-Normalized Weather Billed energy Forecast

Non-normalized Weather Billed Energy Forecast						
Year	Residential	General Service < 50	General Service > 50	Streetlights	USL	Total
Non-normalized Weather Billed Energy Forecast (kWh)						
2011	93,665,802	18,835,799	68,664,764	1,575,556	368,368	183,110,288
2012	95,523,010	18,891,626	70,343,497	1,578,145	355,293	186,691,572

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 179.8 GWh for 2011 and 181.7 GWh for 2012.

The difference between the non-normalized and normalized forecast adjustments is 3.3 GWh in 2011 (i.e. 183.1 - 179.8) and 5.0 GWh in 2012 (i.e. 186.7 -181.7). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for Grimsby Power Inc. for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3.13 Weather Sensitivity by Rate Class

Residential	GS>50kW	Street Lighting	GS<50	USL
75.90%	51.81%	0.00%	75.90%	0.00%

For the General Service >50 class the weather sensitivity amount of 51.81% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications (by other LDC's) that these two classes are 100% weather sensitive. Intervener's expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. Grimsby Power Inc. agrees with this position but also submits that the weather sensitivity for the Residential and General Service < 50 kW classes should be higher than the General Service >50kW class. As a result, Grimsby Power Inc. has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 51.81%, or 75.9%.

The difference between the non-normalized and normalized forecast of 3.3 GWh in 2011 and 5.0 GWh in 2012 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity. Table 3.14 outlines how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast.

Table 3.14 Alignment of Non-Normal to Weather Normal Forecast

Alligment of Non-normal to Weather Normal Forecast						
Year	**Residential**	**GS < 50**	**General Service > 50**	**Streetlight**	**USL**	**Total**
Non-normalized Weather Billed Energy Forecast (kWh)						
2011 Non-Normalized Bridge	**93,665,802**	**18,835,799**	**68,664,764**	**1,575,556**	**368,368**	**183,110,288**
2012 Non-Normalized Test	**95,523,010**	**18,891,626**	**70,343,497**	**1,578,145**	**355,293**	**186,691,572**
Adjustment for Weather (kWh)						
2010	**1,965,837**	**395,321**	**983,625**	**-**	**-**	**- 3,344,783**
2011	**2,916,167**	**576,732**	**1,465,742**	**-**	**-**	**- 4,958,641**
Weather Normalized Billed Energy Forecast (kWh)						
2011 Normalized Test	**91,699,965**	**18,440,477**	**67,681,139**	**1,575,556**	**368,368**	**179,765,505**
2012 Normalized Test	**92,606,843**	**18,314,894**	**68,877,755**	**1,578,145**	**355,293**	**181,732,931**

Billed kW Load Forecast

There are two rate classes (that apply to Grimsby Power Inc.) that charge volumetric distribution on per kW basis. These include General Service >50 and Street Lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

Table 3.15 outlines the annual demand units by applicable rate class.

Table 3.15 Historical Annual kW per Applicable Rate Class

Historical Annual kW per Applicable Rate Class			
Year	**General Service > 50**	**Streetlight**	**Total**
Billed Annual kW			
2003	**160,595**	**4,664**	**165,259**
2004	**162,044**	**4,380**	**166,424**
2005	**174,384**	**4,445**	**178,829**
2006	**175,422**	**4,425**	**179,846**
2007	**176,460**	**4,378**	**180,838**
2008	**172,781**	**4,443**	**177,225**
2009	**172,057**	**4,322**	**176,379**
2010	**174,346**	**4,359**	**178,705**

Table 3.16 illustrates the historical ratio of kW/kWh as well as the average ratio for 2003 to 2010.

Table 3.16 Historical kW / kWh Ratio per Applicable Rate Class

Historical kW/KWh Ratio per Applicable Rate Class		
Year	**General Service > 50**	**Streetlight**
Ratio of kW to kWh		
2003	**0.2837%**	**0.2999%**
2004	**0.2831%**	**0.2734%**
2005	**0.2839%**	**0.2764%**
2006	**0.2762%**	**0.2761%**
2007	**0.2682%**	**0.2764%**
2008	**0.2659%**	**0.2757%**
2009	**0.2709%**	**0.2770%**
2010	**0.2601%**	**0.2771%**
Average 2003 to 2010	**0.2740%**	**0.2790%**

The average ratio was applied to the weather normalized billed energy forecast in Table 3.14 to provide the forecast of kW by rate class as shown below. The following Table 3.17 outlines the forecast of kW for the applicable rate classes.

Table 3.17 kW Forecast by Applicable Rate Class

kW Forecast by Applicable Rate Class			
Year	**General Service > 50**	**Streetlight**	**Total**
Predicted Billed kW			
2011 Normalized Bridge	**185,444**	**4,396**	**189,840**
2012 Normalized Test	**188,723**	**4,403**	**193,126**

Table 3.18 provides a summary of the billing determinants by rate classes that are used to develop the proposed rates.

Table 3.18 Summary of Forecast

Summary of Forecast	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Weather Normalized Bridge	2012 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES								
Actual kWh Purchases		177,010,661	182,668,136	181,594,867	179,620,065	188,942,673		
Predicted kWh Purchases before CDM adjustment		176,003,138	181,037,961	179,969,738	179,042,205	186,939,473	188,013,819	190,071,518
% Difference of actual and predicted purchases		-0.6%	-0.9%	-0.9%	-0.3%	-1.1%		
BILLING DETERMINANTS BY CLASS								
Residential								
Customers	8,535	8,715	8,825	9,007	9,147	9,290	9,495	9,703
kWh	87,224,776	85,590,832	86,770,665	86,978,306	86,819,996	91,844,703	91,699,965	92,606,843
GS<50								
Customers	706	639	657	656	662	669	676	683
kWh	18,430,695	17,886,710	18,502,908	18,161,547	18,343,495	18,780,136	18,440,477	18,314,894
GS > 50 kW								
Customers	115	114	102	105	100	102	101	100
kWh	53,991,726	63,517,727	65,799,685	64,972,194	63,520,024	67,026,092	67,681,139	68,877,755
kW	178,363	175,422	176,460	172,781	172,057	174,346	185,444	188,723
Streetlights								
Connections	2,477	2,493	2,493	2,529	2,486	2,512	2,530	2,548
kWh	1,576,635	1,602,773	1,584,019	1,611,475	1,560,091	1,572,970	1,575,556	1,578,145
kW	4,433	4,425	4,378	4,443	4,322	4,359	4,396	4,403
USL								
Customers	82	85	84	85	82	80	80	80
kWh	413,657	427,433	411,704	352,317	376,487	381,924	368,368	355,293
Total								
Customer/Connections	11,915	12,046	12,161	12,382	12,477	12,654	12,882	13,114
kWh	161,637,489	169,025,475	173,068,981	172,075,839	170,620,093	179,605,826	179,765,505	181,732,931
kW from applicable classes	182,796	179,846	180,838	177,225	176,379	178,705	189,840	193,126

OPERATING REVENUE VARIANCE ANALYSIS

Variance Analysis on Throughput Revenue

A summary of historical and forecast operating revenues is presented in Table 3.19. Grimsby Power Inc.'s distribution revenue has been calculated using its most recently approved rates. Throughput revenue does not include commodity-related revenue.

A variance analysis for the other net operating revenue will be provided further in this Exhibit.

2006 Board Approved

Grimsby Power Inc.'s total 2006 Board Approved operating revenue was forecast to be $3,523,265. Throughput revenue of $3,195,505 represented 90.7% of total operating revenue. Other net operating revenue accounts for the remaining $ 327,760.

2006 Actual

Grimsby Power Inc.'s operating revenue in fiscal 2006 was $3,467,083. Throughput revenue was $3,134,614 or 90.4% of total revenues. Other net operating revenue accounts for the remaining $332,469.

Table 3.19 Variance Analysis – Throughput Revenue – 2006 Board Approved to 2006 Actual

Throughput Revenue	2006 Board Approved $	2006 Actual $	Variance from 2006 Board Approved $	Variance %
Residential	2,288,126	2,295,686	7,560	0.33%
GS<50	399,613	362,401	(37,212)	-9%
GS>50	456,622	414,378	(42,244)	-9%
Streetlight	17,381	33,270	15,889	91%
Unmetered Scattered Load	33,763	28,879	(4,884)	-14%
Total Throughput Revenue	**3,195,505**	**3,134,614**	**(60,891)**	**-1.91%**

Throughput revenue for 2006 was (1.91)% or $(60,891) lower than the amounts approved in the 2006 EDR primarily due to lower kWh usage in the unmetered scattered load and general service classes.

The timing difference between the 2006 Actual amounts which are based on the fiscal year of January 1 to December 31, 2006, and the 2006 EDR amounts, which are based on the rate year of May 1, 2006 to April 30,2007 also contribute to the variance, since the 2006 rates did not come into effect until May 2006.

Table 3.20 below compares the 2006 EDR Approved billing quantities to the 2006 Actual quantities.

Table 3.20 Variance Analysis – Billing Quantities – 2006 Board Approved to 2006 Actual

	Customers/Connections			kWh			kW		
Rate Class	2006 EDR	2006 Actual	Variance		2006 EDR	2006 Actual	2006 EDR	2006 Actual	Volumetric Variance
Residential	8,535	8,715	180	kWh	87,224,776	85,590,832			(1,633,944)
GS < 50	706	639	(67)	kWh	18,430,695	17,886,710			(543,985)
GS > 50	115	114	(1)	kW			178,363	175,422	(2,941)
Streetlight	2,477	2,493	16	kW			4,433	4,425	(8)
USL	82	85	3	kWh	413,657	427,433			13,776
Total	11,915	12,046	131		106,069,128	103,904,975	182,796	179,846	(2,167,103)
					Variance	(2,164,153)		(2,950)	

2007 Actual

Grimsby Power Inc.'s operating revenue in fiscal 2007 was $3,657,304, as shown in Table 3.1. Throughput revenue totalled $3,254,893 or 89.0% of total revenues. Other net operating revenue accounts for the remaining revenue of $402,411.

Table 3.21 Variance Analysis – Throughput Revenue – 2007 Actual to 2006 Actual

Throughput Revenue	2006 Actual $	2007 Actual $	Variance from 2006 Actual $	Variance %
Residential	2,295,686	2,384,473	88,787	3.87%
GS<50	362,401	389,142	26,741	7.38%
GS>50	414,378	423,305	8,927	2.15%
Streetlight	33,270	33,953	683	2.05%
Unmetered Scattered Load	28,879	24,020	(4,859)	-16.83%
Total Throughput Revenue	**3,134,614**	**3,254,893**	**120,279**	**3.84%**

The 2007 throughput revenue was $120,279 or 3.84% higher than the 2006 actual revenue. The revenue increase is mainly due to higher kWh usage in the residential and GS<50 classes and due to timing differences between the fiscal and rate year periods, as January 1 2007 to April 30 2007 reflected the full impact of the 2006 EDR rate increase, and IRM adjustments between May 1, 2007 and December 31, 2007.

Table 3.22 below compares the 2007 Actual billing quantities to the 2008 Actual quantities.

Table 3.22 Variance Analysis – Billing Quantities – 2007 Actual to 2006 Actual

	Customers/Connections			kWh			kW		
Rate Class	2006 Actual	2007 Actual	Variance		2006 Actual	2007 Actual	2006 Actual	2007 Actual	Volumetric Variance
Residential	8,715	8,825	110	kWh	85,590,832	86,770,665			1,179,833
GS < 50	639	657	18	kWh	17,886,710	18,502,908			616,198
GS > 50	114	102	(12)	kW			175,422	176,460	1,039
Streetlight	2,493	2,493	-	kW			4,425	4,378	(47)
USL	85	84	(1)	kWh	427,433	411,704			(15,729)
Total	12,046	12,161	115		103,904,975	105,685,276	179,846	180,838	1,781,293
					Variance	1,780,301		992	

2008 Actual

Grimsby Power Inc.'s operating revenue in fiscal 2008 was $3,716,664, as shown in Table 3.1. Throughput revenue totalled $3,298,205 or 88.7% of total revenues. Other net operating revenue accounts for the remaining revenue of $418,459.

Table 3.23 Variance Analysis – Throughput Revenue – 2008 Actual to 2007 Actual

Throughput Revenue	2007 Actual $	2008 Actual $	Variance from 2007 Actual $	Variance %
Residential	2,384,473	2,427,790	43,317	1.82%
GS<50	389,142	385,108	(4,034)	-1.04%
GS>50	423,305	431,890	8,585	2.03%
Streetlight	33,953	34,488	535	1.58%
Unmetered Scattered Load	24,020	18,929	(5,091)	-21.19%
Total Throughput Revenue	**3,254,893**	**3,298,205**	**43,312**	**1.33%**

The 2008 throughput revenue was $42,312 or 1.33% higher than the 2007 actual revenue. The increased usage from residential customers was offset by reductions in all other classes. Despite load reductions the revenue increased for almost all rate classes due to timing differences between the fiscal and rate year periods, as January 1 2008 to April 30 2008 reflected the full impact of the 2006 EDR rate increase, and IRM adjustments between May 1, 2008 and December 31, 2008.

Table 3.24 below compares the 2007 Actual billing quantities to the 2008 Actual quantities.

Table 3.24 Variance Analysis – Billing Quantities – 2008 Actual to 2007 Actual

	Customers/Connections			kWh			kW		
Rate Class	2007 Actual	2008 Actual	Variance		2007 Actual	2008 Actual	2007 Actual	2008 Actual	Volumetric Variance
Residential	8,825	9,007	182	kWh	86,770,665	86,978,306			207,641
GS < 50	657	656	(1)	kWh	18,502,908	18,161,547			(341,361)
GS > 50	102	105	3	kW			176,460	172,781	(3,679)
Streetlight	2,493	2,529	36	kW			4,378	4,443	66
USL	84	85	1	kWh	411,704	352,317			(59,387)
Total	12,161	12,382	221		105,685,276	105,492,169	180,838	177,224	(196,721)
					Variance	(193,107)		(3,614)	

2009 Actual

Grimsby Power Inc.'s operating revenue for 2009 was $3,668,091, as shown in Table 3.1. Throughput revenue was $3,287,668 or 89.6% of total revenues. Net other operating revenue accounts for the remaining revenue of $380,422.

Table 3.25 Variance Analysis – Throughput Revenue – 2009 Actual to 2008 Actual

Throughput Revenue	2008 Actual $	2009 Actual $	Variance from 2008 Actual $	Variance %
Residential	2,427,790	2,436,326	8,536	0.35%
GS<50	385,108	386,847	1,739	0.45%
GS>50	431,890	415,633	(16,258)	-3.76%
Streetlight	34,488	32,293	(2,195)	-6.36%
Unmetered Scattered Load	18,929	16,570	(2,359)	-12.46%
Total Throughput Revenue	**3,298,205**	**3,287,668**	**(10,537)**	**-0.32%**

Throughput revenue in 2009 was (0.32)% or $(10,537) lower than in 2008 due to the decreased residential customer volumetric revenue in all customer rate classes which were offset by the general services load increase.

Table 3.26 below compares the 2008 Actual billing quantities to the 2009 Actual quantities.

Table 3.26 Variance Analysis – Billing Quantities – 2009 Actual to 2008 Actual

	Customers/Connections			kWh			kW		
Rate Class	2008 Actual	2009 Actual	Variance		2008 Actual	2009 Actual	2008 Actual	2009 Actual	Volumetric Variance
Residential	9,007	9,147	140	kWh	86,978,306	86,819,996			(158,309)
GS < 50	656	662	6	kWh	18,161,547	18,343,495			181,947
GS > 50	105	100	(5)	kW			172,781	172,057	(724)
Streetlight	2,529	2,486	(43)	kW			4,443	4,322	(122)
USL	85	82	(3)	kWh	352,317	376,487			24,170
Total	12,382	12,477	95		105,492,169	105,539,978	177,224	176,379	46,962
					Variance	47,808		(846)	

2010 Actual

Grimsby Power Inc.'s operating revenue in fiscal 2010 was $3,696,862, as shown in Table 3.1. Throughput revenue totalled $3,351,574 or 90.7% of total revenues. Other net operating revenue accounts for the remaining revenue of $345,288.

Table 3.27 Variance Analysis – Throughput Revenue – 2010 Actual to 2009 Actual

Throughput Revenue	2009 Actual $	2010 Actual $	Variance from 20010 Actual $	Variance %
Residential	2,436,326	2,482,572	46,246	1.90%
GS<50	386,847	393,977	7,130	1.84%
GS>50	415,633	424,827	9,194	2.21%
Streetlight	32,293	34,077	1,784	5.52%
Unmetered Scattered Load	16,570	16,121	(449)	-2.71%
Total Throughput Revenue	**3,287,668**	**3,351,574**	**63,906**	**1.94%**

Throughput revenue increased by 1.94% or $ 63,906 in 2009 and is primarily due to the residential customer growth and usage increase for this class and the 2010 IRM rate increase effective May 1, 2010.

Table 3.28 below compares the 2009 Actual billing quantities to the 2010 Actual quantities.

Table 3.28 Variance Analysis – Billing Quantities – 2010 Actual to 2009 Actual

	Customers/Connections			kWh			kW		
Rate Class	2009 Actual	2010 Actual	Variance		2009 Actual	2010 Actual	2009 Actual	2010 Actual	Volumetric Variance
Residential	9,147	9,290	143	kWh	86,819,996	91,844,703			5,024,706
GS < 50	662	669	7	kWh	18,343,495	18,780,136			436,642
GS > 50	100	102	2	kW			172,057	174,346	2,289
Streetlight	2,486	2,512	26	kW			4,322	4,359	38
USL	82	80	(2)	kWh	376,487	381,924			5,438
Total	12,477	12,653	176		105,539,978	111,006,763	176,379	178,705	5,469,112
					Variance	5,466,786		2,326	

2011 Bridge Year

Grimsby Power Inc.'s operating revenue is forecast to be $3,740,989 as shown in Table 3.1. Throughput revenue totals $3,409,289 or 91.1% of total revenues. Other net operating revenue accounts for the remaining revenue of $331,700.

Table 3.29 Variance Analysis – Throughput Revenue – 2011 Bridge to 2010 Actual

Throughput Revenue	2010 Actual $	2011 Bridge $	Variance from 2011 Bridge $	Variance %
Residential	2,482,572	2,547,789	65,217	2.63%
GS<50	393,977	390,000	(3,977)	-1.01%
GS>50	424,827	422,000	(2,827)	-0.67%
Streetlight	34,077	34,000	(77)	-0.23%
Unmetered Scattered Load	16,121	15,500	(621)	-3.85%
Total Throughput Revenue	**3,351,574**	**3,409,289**	**57,715**	**1.72%**

Total throughput operating revenue is forecast to be 1.72% or $ 57,715 higher than the 2010 amounts. This increase is due to the increase in the number of residential customers.

Table 3.30 below compares the 2011 Bridge billing quantities to the 2010 Actual quantities.

Table 3.30 Variance Analysis – Billing Quantities – 2011 Bridge to 2010 Actual

	Customers/Connections			kWh			kW		
Rate Class	2010 Actual	2011 Bridge	Variance		2010 Actual	2011 Bridge	2010 Actual	2011 Bridge	Volumetric Variance
Residential	9,290	9,495	205	kWh	91,844,703	91,699,965			(144,738)
GS < 50	669	676	7	kWh	18,780,136	18,440,477			(339,659)
GS > 50	102	101	(1)	kW			174,346	185,444	11,098
Streetlight	2,512	2,530	18	kW			4,359	4,396	37
USL	80	80	-	kWh	381,924	368,368			(13,556)
Total	12,653	12,882	229		111,006,763	110,508,811	178,705	189,840	(486,818)
					Variance	(497,953)		11,135	

2012 Test Year

Grimsby Power Inc.'s 2012 Test Year operating revenue is forecast to be $ 4,243,703 as shown in Table 3.1. Throughput revenue totals $3,430,927 or 92.6% of total revenues. Other operating revenue (net), accounts for the remaining revenue of $339,741.

Table 3.31 Variance Analysis – Throughput Revenue – 2012 Test to 2011 Bridge

Throughput Revenue	2011 Bridge $	2012 Test $	Variance from 2011 Bridge $	Variance %
Residential	2,547,789	3,141,137	593,348	23.29%
GS<50	390,000	492,337	102,337	26.24%
GS>50	422,000	509,054	87,054	20.63%
Streetlight	34,000	80,351	46,351	136.33%
Unmetered Scattered Load	15,500	20,824	5,324	34.35%
Total Throughput Revenue	**3,409,289**	**4,243,703**	**834,414**	**24.47%**

Total throughput revenue is forecast to be $ 834,414 or 24.47% higher than the 2011 Bridge year. This variance is due to increased revenue required as determined through the Revenue Deficiency of $812,776. Exhibit 6 provides further details on the revenue deficiency for 2012 Test year. As a result of this rate application, Grimsby Power Inc. expects to increase its rate base by $4.2 million or 25.75% over the 2006 EDR rate base as explained in Exhibit 2.

Table 3.32 below compares the 2011 Bridge Year billing quantities to the 2012 Test Year billing quantities.

Table 3.32 Variance Analysis – Billing Quantities – 2012 Test to 2011 Bridge

	Customers/Connections			kWh			kW		
Rate Class	2011 Bridge	2012 Test	Variance	2011 Bridge		2012 Test	2011 Bridge	2012 Test	Variance
Residential	9,495	9,703	208	kWh	91,699,965	92,606,843			906,878
GS < 50	676	683	7	kWh	18,440,477	18,314,894			(125,583)
GS > 50	101	100	(1)	kW			185,444	188,723	3,279
Streetlight	2,530	2,548	18	kW			4,396	4,403	7
USL	80	80	-	kWh	368,368	355,293			(13,075)
Total	12,882	13,114	232		110,508,811	111,277,030	189,840	193,126	771,506
					Variance	768,220		3,286	

TRANFORMER ALLOWANCE

Grimsby Power Inc. currently provides a Transformer Ownership Allowance Credit of $0.60 per kW of demand per month for all customers who own their own transformation facilities (transformer).

Grimsby Power Inc. is proposing to maintain the rate of $0.60 per kW of demand per month for the 2012 Test Year for eligible customers.

VARIANCE ANALYSIS ON OTHER OPERATING REVENUE

Overview

Grimsby Power Inc.'s service revenue requirement for the purposes of this application is $ 4,583,444, and the base revenue requirement is $4,243,703. The materiality threshold used to analyze Other Operating Revenue accounts in accordance with the Filing Requirements is $50,000 for distributors with a distribution revenue requirement less than or equal to $10 million.

Table 3.33 provides a summary of Other Operating Revenue between 2006 Actual through to 2012 Test Year amounts.

Table 3.33 Summary of Other Operating Revenue (Board Appendix 2-C)

Appendix 2-C
Other Operating Revenue

USoA #	USoA Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
4235	Specific Service Charges	$ 33,206	$ 34,494	$ 34,543	$ 66,027	$ 59,377	$ 55,000	$ 55,000
4225	Late Payment Charges	$ 43,631	$ 59,851	$ 56,481	$ 58,427	$ 53,582	$ 55,000	$ 55,000
4080	SSS Admin Fees	$ 25,172	$ 24,769	$ 25,372	$ 25,805	$ 26,200	$ 26,200	$ 26,750
4082	Retail Services Revenues	$ 12,787	$ 17,264	$ 16,784	$ 16,422	$ 18,397	$ 21,300	$ 25,591
4084	STR Revenues	$ 885	$ 516	$ 282	$ 275	$ 544	$ 600	$ 800
4210	Rent from Electric Property	$ 77,419	$ 65,488	$ 66,471	$ 69,332	$ 65,185	$ 65,000	$ 65,000
4325	Revenues from Merchandise, Jobbing, Etc	$ 26,933	$ 70,442	$ 64,494	$ 102,212	$ 96,264	$ 100,000	$ 100,000
4355	Gain on Disposition of Utility & Other Property	$ 540	$ 1,000	$ 110		$ 300		
4375	Revenues from Non-Utility & Other Property	$ 2,265	$ 3,405	$ 150,977	$ 209,700	$ 162,065	$ 98,600	$ 98,600
4380	Expenses of Non-Utility Operations			-$ 118,572	-$ 181,822	-$ 155,709	-$ 95,000	-$ 95,000
4390	Miscellaneous Non-Operating Income	$ 4,098	$ 2,486	$ 3,953	$ 3,414	$ 8,905	$ 2,000	$ 5,000
4405	Interest and Dividend Income	$ 105,534	$ 122,696	$ 117,564	$ 10,630	$ 10,180	$ 3,000	$ 3,000
Specific Service Charges		$ 33,206	$ 34,494	$ 34,543	$ 66,027	$ 59,377	$ 55,000	$ 55,000
Late Payment Charges		$ 43,631	$ 59,851	$ 56,481	$ 58,427	$ 53,582	$ 55,000	$ 55,000
Other Operating Revenues		$ 116,262	$ 108,037	$ 108,909	$ 111,834	$ 110,325	$ 113,100	$ 118,141
Other Income or Deductions		$ 139,370	$ 200,029	$ 218,526	$ 144,135	$ 122,004	$ 108,600	$ 111,600
Total		$ 332,469	$ 402,411	$ 418,459	$ 380,422	$ 345,288	$ 331,700	$ 339,741

Variance Analysis – Other Operating Revenue – 2006 Actual to 2006 Board Approved

Table 3.34 below summarizes the variance by account description followed by a discussion on those variances over $50,000.

Table 3.34 Variance Analysis – Other Operating Revenue – 2006 Actual to 2006 Board Approved

Account	Description	2006 Board Approved	2006 Actual	$ Variance	% Variance
4235	Specific Service Charges	103,981	33,206	(70,775)	-68.1%
4225	Late Payment Charges	14,073	43,631	29,558	210.03%
4080	SSS Admin Fees	27,592	25,172	(2,420)	-8.77%
4082	Retail Services Revenues	8,162	12,787	4,625	56.66%
4084	STR Revenues	26	885	859	3302.88%
4210	Rent from Electric Property	54,875	77,419	22,544	41.08%
4325	Revenues from Merchandise, Jobbing, Etc.	91,052	26,933	(64,119)	-70.42%
4355	Gain on Disposition of Utility & Other Property	1,212	540	(672)	-55.45%
4375	Revenues from Non-Utility Operation	-	2,265	2,265	0.00%
4380	Expenses of Non-Utility Operations	-	-	-	0.00%
4390	Miscellaneous Non-Operating Income	2,131	4,098	1,967	92.32%
4405	Interest and Dividend Income	24,656	105,534	80,878	328.03%
Specifice Service Charges		103,981	33,206	(70,775)	-68.1%
Late Payment Charges		14,073	43,631	29,558	210.0%
Other Distribution Revenues		90,655	116,262	25,607	28.2%
Other Income and Expenses		119,051	139,370	20,319	17.1%
Total Revenue Offsets		**327,760**	**332,469**	**4,709**	**1.44%**

Specific Service Charges

The 2006 Board Approved Specific Service Charges for $103,981 included $27,401 for revenue from access to the power poles. In 2006, this revenue had been recognized in account 4210. Also the 2006 Set up Change/Change of Occupancy Charge was $ 14,285 lower than the amounts approved in the 2006 EDR. The remaining variance between the 2006 Board Approved Specific Service Charges and 2006 actual is a split amount between collection, disconnections/reconnections, and install/remove load control device and interval meter interrogations fees.

Variance Analysis – Other Operating Revenue – 2007 Actual to 2006 Actual

Table 3.35 below summarizes the variance by account description followed by a discussion on those variances.

Table 3.35 Variance Analysis – Other Operating Revenue – 2007 Actual to 2006 Actual

Account	Description	2006 Actual	2007 Actual	$ Variance	% Variance
4235	Specific Service Charges	33,206	34,494	1,288	3.88%
4225	Late Payment Charges	43,631	59,851	16,220	37.18%
4080	SSS Admin Fees	25,172	24,769	(403)	-1.60%
4082	Retail Services Revenues	12,787	17,264	4,478	35.02%
4084	STR Revenues	885	516	(369)	-41.68%
4210	Rent from Electric Property	77,419	65,488	(11,931)	-15.41%
4325	Revenues from Merchandise, Jobbing, Etc.	26,933	70,442	43,509	161.55%
4355	Gain on Disposition of Utility & Other Property	540	1,000	460	85.19%
4375	Revenues from Non-Utility Operation	2,265	3,405	1,140	50.33%
4380	Expenses of Non-Utility Operations	-	-	-	0.00%
4390	Miscellaneous Non-Operating Income	4,098	2,486	(1,613)	-39.35%
4405	Interest and Dividend Income	105,534	122,696	17,162	16.26%
Specifice Service Charges		33,206	34,494	1,288	3.88%
Late Payment Charges		43,631	59,851	16,220	37.18%
Other Distribution Revenues		116,262	108,037	(8,225)	-7.07%
Other Income and Expenses		139,370	200,029	60,659	43.52%
Total Revenue Offsets		**332,469**	**402,411**	**69,942**	**21.04%**

Other Income and Expenses

The Revenues from Merchandise, Jobbing Income of $ 70,442 was 161.55% or $ 43,509 higher due to the selling transformers, two larger jobs: 496 Inglehart and 30 Tops Drive. Interest and dividend income of $ 122,696 was 16.26% or $ 17,162 higher than the 2006 due to higher than expected interest earned on bank accounts.

Variance Analysis – Other Operating Revenue – 2008 Actual to 2007 Actual

Table 3.36 below summarizes the variance by account description followed by a discussion on those variances.

Table 3.36 Variance Analysis – Other Operating Revenue – 2008 Actual to 2007 Actual

Account	Description	2007 Actual	2008 Actual	$ Variance	% Variance
4235	Specific Service Charges	34,494	34,543	49	0.14%
4225	Late Payment Charges	59,851	56,481	(3,370)	-5.63%
4080	SSS Admin Fees	24,769	25,372	603	2.43%
4082	Retail Services Revenues	17,264	16,784	(480)	-2.78%
4084	STR Revenues	516	282	(234)	-45.35%
4210	Rent from Electric Property	65,488	66,471	983	1.50%
4325	Revenues from Merchandise, Jobbing, Etc.	70,442	64,494	(5,948)	-8.44%
4355	Gain on Disposition of Utility & Other Property	1,000	110	(890)	-89.00%
4375	Revenues from Non-Utility Operation	3,405	150,977	147,572	4333.98%
4380	Expenses of Non-Utility Operations	-	(118,572)	(118,572)	100.00%
4390	Miscellaneous Non-Operating Income	2,486	3,953	1,467	59.02%
4405	Interest and Dividend Income	122,696	117,564	(5,132)	-4.18%
Specifice Service Charges		34,494	34,543	49	0.14%
Late Payment Charges		59,851	56,481	(3,370)	-5.63%
Other Distribution Revenues		108,037	108,909	872	0.81%
Other Income and Expenses		200,029	218,526	18,497	9.25%
Total Revenue Offsets		**402,411**	**418,459**	**16,048**	**3.99%**

All summary accounts are below the materiality threshold.

Variance Analysis – Other Operating Revenue – 2009 Actual to 2008 Actual

Table 3.37 below summarizes the variance by account description followed by a discussion on those variances.

Table 3.37 Variance Analysis – Other Operating Revenue – 2009 Actual to 2008 Actual

Account	Description	2008 Actual	2009 Actual	$ Variance	% Variance
4235	Specific Service Charges	34,543	66,027	31,484	91.14%
4225	Late Payment Charges	56,481	58,427	1,946	3.45%
4080	SSS Admin Fees	25,372	25,805	433	1.71%
4082	Retail Services Revenues	16,784	16,422	(362)	-2.16%
4084	STR Revenues	282	275	(8)	-2.66%
4210	Rent from Electric Property	66,471	69,332	2,861	4.30%
4325	Revenues from Merchandise, Jobbing, Etc.	64,494	102,212	37,718	58.48%
4355	Gain on Disposition of Utility & Other Property	110	-	(110)	-100.00%
4375	Revenues from Non-Utility Operation	150,977	209,700	58,723	38.90%
4380	Expenses of Non-Utility Operations	(118,572)	(181,822)	(63,250)	53.34%
4390	Miscellaneous Non-Operating Income	3,953	3,414	(539)	-13.63%
4405	Interest and Dividend Income	117,564	10,630	(106,934)	-90.96%
Specifice Service Charges		34,543	66,027	31,484	91.14%
Late Payment Charges		56,481	58,427	1,946	3.45%
Other Distribution Revenues		108,909	111,834	2,925	2.69%
Other Income and Expenses		218,526	144,135	(74,391)	-34.04%
Total Revenue Offsets		**418,459**	**380,422**	**(38,037)**	**-9.09%**

Other Income and Expenses

2009 Revenues from Non-Utility Operations increased by $58,723, or 38.90% over the 2008 amount of $105,977, and 2009 Expenses from Non-Utility Operations increased $ 63,250 or 53.34% over 2008 amounts resulted in a net expense of $9,527.

Interest and Dividend income for 2009 was $106,934 lower than 2008 actual amounts attributable to the dividends paid and declining interest rates, resulting in lower bank account interest revenue.

Variance Analysis – Other Operating Revenue – 2010 Actual to 2009 Actual
Table 3.38 below summarizes the variance by account description.

Table 3.38 Variance Analysis – Other Operating Revenue – 2010 Actual to 2009 Actual

Account	Description	2009 Actual	2010 Actual	$ Variance	% Variance
4235	Specific Service Charges	66,027	59,377	(6,650)	-10.07%
4225	Late Payment Charges	58,427	53,582	(4,845)	-8.29%
4080	SSS Admin Fees	25,805	26,200	394	1.53%
4082	Retail Services Revenues	16,422	18,397	1,975	12.03%
4084	STR Revenues	275	544	269	98.12%
4210	Rent from Electric Property	69,332	65,185	(4,148)	-5.98%
4325	Revenues from Merchandise, Jobbing, Etc.	102,212	96,264	(5,948)	-5.82%
4355	Gain on Disposition of Utility & Other Property	-	300	300	100.00%
4375	Revenues from Non-Utility Operation	209,700	162,065	(47,636)	-22.72%
4380	Expenses of Non-Utility Operations	(181,822)	(155,709)	26,112	-14.36%
4390	Miscellaneous Non-Operating Income	3,414	8,905	5,491	160.83%
4405	Interest and Dividend Income	10,630	10,180	(450)	-4.23%
Specifice Service Charges		66,027	59,377	(6,650)	-10.07%
Late Payment Charges		58,427	53,582	(4,845)	-8.29%
Other Distribution Revenues		111,834	110,325	(1,509)	-1.35%
Other Income and Expenses		144,135	122,004	(22,131)	-15.35%
Total Revenue Offsets		**380,422**	**345,288**	**(35,134)**	**-9.24%**

All summary accounts are below the materiality threshold.

Variance Analysis – Other Operating Revenue – 2011 Bridge to 2010 Actual
Table 3.39 below summarizes the variance by account description.

Table 3.39 Variance Analysis – Other Operating Revenue – 2011 Bridge to 2010 Actual

Account	Description	2010 Actual	2011 Bridge	$ Variance	% Variance
4235	Specific Service Charges	59,377	55,000	(4,377)	-7.37%
4225	Late Payment Charges	53,582	55,000	1,418	2.65%
4080	SSS Admin Fees	26,200	26,200	0	0.00%
4082	Retail Services Revenues	18,397	21,300	2,903	15.78%
4084	STR Revenues	544	600	56	10.33%
4210	Rent from Electric Property	65,185	65,000	(185)	-0.28%
4325	Revenues from Merchandise, Jobbing, Etc.	96,264	100,000	3,736	3.88%
4355	Gain on Disposition of Utility & Other Property	300	-	(300)	-100.00%
4375	Revenues from Non-Utility Operation	162,065	98,600	(63,465)	-39.16%
4380	Expenses of Non-Utility Operations	(155,709)	(95,000)	60,709	-38.99%
4390	Miscellaneous Non-Operating Income	8,905	2,000	(6,905)	-77.54%
4405	Interest and Dividend Income	10,180	3,000	(7,180)	-70.53%
Specifice Service Charges		59,377	55,000	(4,377)	-7.37%
Late Payment Charges		53,582	55,000	1,418	2.65%
Other Distribution Revenues		110,325	113,100	2,775	2.52%
Other Income and Expenses		122,004	108,600	(13,404)	-10.99%
Total Revenue Offsets		**345,288**	**331,700**	**(13,588)**	**-3.94%**

All summary accounts are below the materiality threshold.

Variance Analysis – Other Operating Revenue – 2012 Test to 2011 Bridge

Table 3.40 below summarizes the variance by account description.

Table 3.40 Variance Analysis – Other Operating Revenue – 2012 Test to 2011 Bridge

Account	Description	2011 Bridge	2012 Test	$ Variance	% Variance
4235	Specific Service Charges	55,000	55,000	-	0.00%
4225	Late Payment Charges	55,000	55,000	-	0.00%
4080	SSS Admin Fees	26,200	26,750	550	2.10%
4082	Retail Services Revenues	21,300	25,591	4,291	20.15%
4084	STR Revenues	600	800	200	33.33%
4210	Rent from Electric Property	65,000	65,000	-	0.00%
4325	Revenues from Merchandise, Jobbing, Etc.	100,000	100,000	-	0.00%
4355	Gain on Disposition of Utility & Other Property	-	-	-	
4375	Revenues from Non-Utility Operation	98,600	98,600	-	0.00%
4380	Expenses of Non-Utility Operations	(95,000)	(95,000)	-	0.00%
4390	Miscellaneous Non-Operating Income	2,000	5,000	3,000	150.00%
4405	Interest and Dividend Income	3,000	3,000	-	0.00%
Specifice Service Charges		55,000	55,000	-	0.00%
Late Payment Charges		55,000	55,000	-	0.00%
Other Distribution Revenues		113,100	118,141	5,041	4.46%
Other Income and Expenses		108,600	111,600	3,000	2.76%
Total Revenue Offsets		**331,700**	**339,741**	**8,041**	**2.42%**

All summary accounts are below the materiality threshold.

SPECIFIC SERVICE CHARGES

Grimsby Power Inc. is proposing to maintain its existing specific service charges which are consistent with the OEB's Standard Rates.

Request to Maintain Current Rates and Specific Charges

Grimsby Power Inc. anticipates no material changes to the following Specific Service Charge revenue and proposes to maintain the current rates for the following:

Item Description (Rate Code)	Calculation Basis	Rate ($)
Arrears Certificate (1)	Standard	15.00
Statement of Account (2)	Standard	15.00
Pulling Post Dated Cheques (3)	Standard	15.00
Duplicate Invoices for Previous Billing (4)	Standard	15.00
Easement Letter (5)	Standard	15.00
Account History (6)	Standard	15.00
Credit Reference/Credit Check (Plus Credit Agency Costs) (7)	Standard	15.00
Returned Cheque Charge (8)	Standard	15.00
Charge to Certify Cheque (9)	Standard	15.00
Legal Letter Charge (10)	Standard	15.00
Account Set Up Charge/Change of Occupancy Charge (Plus Credit Agency Costs if Applicable) (11)	Standard	30.00
Special meter reads (12)	Standard	30.00
Meter Dispute Chare plus Meter Measurement Canada Fees (13)	Standard	30.00
Interval Meter interogation (14)	Standard	20.00
Late Payment - per Month (15)	%	1.50
Late Payment - per Month (16)	%	19.56
Collection of Account Charge - No Disconnection (17)	Standard	30.00
Collection of Account Charge - No Disconnection - After Regular Hours (18)	Standard	165.00
Disconnect/Reconnect at Meter - During Regular Hours (19)	Standard	65.00
Disconnect/Reconnect at Meter - After Regular Hours (21)	Standard	185.00
Disconnect/Reconnect at Pole - During Regular Hours (20)	Standard	185.00
Disconnect/Reconnect at Pole - After Regular Hours (22)	Standard	415.00
Service call - Customer Owned Equipment (25)	Standard	30.00
Service Call - After Regular Hours (26)	Standard	165.00
Install/Remove Load Control Device - During Regular Hours (27)	Standard	65.00
Install/Remove Load Control Device - After Regular Hours (28)	Standard	185.00
Temporary Service Install & Remove - Overhead - No Transformer (29)	Standard	500.00
Temporary Service Install & Remove - Underground - No Transformer (30)	Standard	300.00
Temporary Service Install & Remove - Overhead - with Transformer (31)	Standard	1,000.00
Specific Charge for Access to the Power Poles $/Pole/Year (32)	Standard	22.35

Request to Remove Specific Service Charge

Grimsby Power Inc. proposes to remove the Prepaid Meter – Monthly Service Charge from its Schedule of Rates as this option is no longer available.

Other Operating Revenue and Other Income or Deductions

For each "Other Operating Revenue" and "Other Income or Deductions" accounts with a balance greater than $ 25,000, a detailed breakdown of the account components is presented below.

Table 3.41 Standard Supply Service Administration Fees

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
SSS - RESIDENTIAL	$ 22,936	$ 22,539	$ 23,161	$ 23,636	$ 24,071	$ 24,000	$ 24,500
SSS CHARGES <50	$ 1,571	$ 1,746	$ 1,729	$ 1,716	$ 1,736	$ 1,750	$ 1,800
SSS CHARGES > 50	$ 233	$ 187	$ 228	$ 209	$ 155	$ 200	$ 200
SSS CHARGES STREETLIGHTIN	$ 146	$ 12	$ 8	$ 3	$ 3		
SSS CHARGES - GENERAL	$ 286	$ 285	$ 245	$ 241	$ 235	$ 250	$ 250
Total	$ 25,172	$ 24,769	$ 25,372	$ 25,805	$ 26,200	$ 26,200	$ 26,750

Table 3.42 Rent from Electricity Property

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Bell	$ 32,841	$ 19,422	$ 19,422	$ 19,422	$ 19,623	$ 19,500	$ 19,500
Cogeco	$ 29,581	$ 29,581	$ 29,603	$ 29,603	$ 29,603	$ 29,600	$ 29,600
Other (NRBN,Pen West, Rogers, Niagara Peninsula Energy Inc	$ 14,997	$ 16,485	$ 17,446	$ 20,307	$ 15,958	$ 15,900	$ 15,900
Total	$ 77,419	$ 65,488	$ 66,472	$ 69,333	$ 65,185	$ 65,000	$ 65,000

Table 3.43 Revenues from Merchandise, Jobbing etc.

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Number of Jobs	127	64	74	64	63	65	65
Average per job	$ 212	$ 1,101	$ 872	$ 1,597	$ 1,528	$ 1,538	$ 1,538
Total	$ 26,933	$ 70,442	$ 64,494	$ 102,212	$ 96,264	$ 100,000	$ 100,000

Table 3.43 summarizes the amount and source of interest income from the 2006 Actual to 2012 Test Years. Dividends payment, declining interest rates and lower bank account balances account for the overall decline in revenues. Variance Account Carrying Charges, while noted in this Table, are excluded from the revenue offset amount for the purposes of this rate application.

Table 3.44 Interest and Dividend Income

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Bank Deposit Interest	$ 105,534	$ 122,696	$ 117,564	$ 10,630	$ 10,180	$ 3,000	$ 3,000
Total	$ 105,534	$ 122,696	$ 117,564	$ 10,630	$ 10,180	$ 3,000	$ 3,000

Appendix 3.1 Data for Weather Regression Model

	Purchased	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	Ontario Real GDP Monthly %	Customer	Predicted Purchases
Jan-99	13,003,504	775	0	0	31	105.45	7268	13,003,507
Feb-99	11,162,298	557	0	0	28	106.09	7297	11,047,371
Mar-99	11,921,555	567	0	1	31	106.73	7325	11,603,456
Apr-99	10,363,189	318	0	1	30	107.38	7354	10,459,743
May-99	10,704,841	113	13.6	1	31	108.03	7382	10,850,535
Jun-99	13,176,864	38	86.3	0	30	108.68	7411	13,747,634
Jul-99	16,130,835	1	163.7	0	31	109.34	7439	16,969,516
Aug-99	13,031,373	13	47	0	31	110.00	7468	12,758,561
Sep-99	12,178,222	71	38.5	1	30	110.67	7496	11,335,015
Oct-99	11,063,256	283	0	1	31	111.34	7525	11,028,838
Nov-99	11,592,696	377	0	1	30	112.01	7553	10,889,699
Dec-99	13,308,264	589	0	0	31	112.69	7582	12,861,725
Jan-00	13,415,991	748	0	0	31	113.21	7610	13,363,734
Feb-00	12,143,787	623	0	0	29	113.73	7639	12,130,221
Mar-00	11,928,445	435	0	1	31	114.25	7667	11,655,886
Apr-00	11,034,353	364	0	1	30	114.77	7696	11,032,274
May-00	11,541,279	152	18.7	1	31	115.30	7724	11,588,571
Jun-00	12,766,642	43	38.6	0	30	115.83	7753	12,451,231
Jul-00	13,738,605	12	57.7	0	31	116.36	7781	13,551,358
Aug-00	14,361,462	18	58.3	0	31	116.90	7810	13,626,825
Sep-00	12,355,113	115	30.1	1	30	117.43	7838	11,594,391
Oct-00	11,579,763	231	0.2	1	31	117.97	7867	11,323,396
Nov-00	12,088,646	447	0	1	30	118.52	7895	11,532,901
Dec-00	14,448,465	812	0	0	31	119.06	7924	13,951,437
Jan-01	13,909,294	703	0	0	31	119.23	7952	13,670,812
Feb-01	11,967,330	597	0	0	28	119.40	7981	12,042,039
Mar-01	13,014,848	599	0	1	31	119.58	8009	12,572,426
Apr-01	11,291,502	314	0	1	30	119.75	8038	11,326,210
May-01	11,368,448	142	8.3	1	31	119.92	8066	11,617,458
Jun-01	13,217,050	41	63.7	0	30	120.10	8095	13,804,781
Jul-01	14,116,611	18	79.6	0	31	120.27	8124	14,809,697
Aug-01	15,942,870	1	114	0	31	120.45	8152	16,058,096
Sep-01	12,591,001	93	21.8	1	30	120.62	8181	11,663,822
Oct-01	12,596,897	244	0	1	31	120.80	8209	11,791,343
Nov-01	12,484,655	332	0	1	30	120.97	8238	11,634,391
Dec-01	13,243,351	535	0	0	31	121.15	8266	13,582,471
Jan-02	13,871,887	593	0	0	31	121.50	8295	13,786,611
Feb-02	12,413,923	554	0	0	28	121.86	8323	12,353,497
Mar-02	12,830,040	539	0	1	31	122.22	8352	12,837,744
Apr-02	11,767,060	339	8	1	30	122.59	8380	12,130,346
May-02	11,875,070	249	8.3	1	31	122.95	8409	12,367,250
Jun-02	13,593,688	42	64.7	0	30	123.31	8437	14,282,589
Jul-02	17,361,415	1	151	0	31	123.68	8466	17,817,865
Aug-02	16,216,881	4	94.4	0	31	124.04	8494	15,787,405
Sep-02	14,116,968	33	61.3	1	30	124.41	8523	13,374,571
Oct-02	12,649,930	304	8.9	1	31	124.78	8551	12,733,045
Nov-02	12,214,896	450	0	1	30	125.14	8580	12,415,430
Dec-02	14,076,639	643	0	0	31	125.51	8608	14,336,059

	Purchased	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	Ontario Real GDP Monthly %	Customer	Predicted Purchases
Jan-03	14,687,239	830	-	-	31	125.66	8,660	14,946,647
Feb-03	13,286,182	699	-	-	28	125.81	8,670	13,222,330
Mar-03	13,127,950	593	-	1	31	125.95	8,682	13,418,229
Apr-03	12,005,641	387	-	1	30	126.10	8,721	12,414,410
May-03	11,558,768	216	-	1	31	126.24	8,753	12,407,369
Jun-03	12,773,128	55	41	-	30	126.39	8,772	13,893,650
Jul-03	15,357,469	7	84	-	31	126.54	8,797	15,797,005
Aug-03	15,746,911	6	103	-	31	126.68	8,819	16,508,943
Sep-03	12,329,921	74	15	1	30	126.83	8,862	12,223,420
Oct-03	12,361,911	294	-	1	31	126.98	8,857	12,767,511
Nov-03	12,571,912	392	-	1	30	127.12	8,954	12,725,762
Dec-03	14,155,641	571	-	-	31	127.27	8,973	14,592,748
Jan-04	15,393,531	859	-	-	31	127.53	9,012	15,484,043
Feb-04	13,488,384	648	-	-	29	127.80	9,028	13,982,784
Mar-04	13,192,182	514	-	1	31	128.06	9,080	13,695,954
Apr-04	12,084,383	329	-	1	30	128.32	9,108	12,741,414
May-04	12,393,614	164	14	1	31	128.59	9,139	13,271,892
Jun-04	13,246,270	60	29	-	30	128.85	9,208	14,020,965
Jul-04	14,811,795	8	72	-	31	129.12	9,207	15,874,492
Aug-04	14,277,538	29	40	-	31	129.38	9,237	14,815,455
Sep-04	13,760,318	44	31	1	30	129.65	9,274	13,265,339
Oct-04	12,739,948	254	-	1	31	129.92	9,291	13,206,708
Nov-04	13,474,390	396	-	1	30	130.19	9,312	13,197,545
Dec-04	15,806,180	637	-	-	31	130.45	9,356	15,275,281
Jan-05	15,904,400	766	-	-	31	130.74	9,373	15,674,068
Feb-05	13,355,854	642	-	-	28	131.03	9,380	13,964,013
Mar-05	14,106,535	647	-	1	31	131.33	9,395	14,488,781
Apr-05	12,415,909	339	-	1	30	131.62	9,415	13,163,045
May-05	12,186,547	213	-	1	31	131.91	9,423	13,256,669
Jun-05	16,687,966	13	120	-	30	132.20	9,437	17,493,800
Jul-05	18,388,988	1	145	-	31	132.50	9,449	18,847,237
Aug-05	17,645,309	4	103	-	31	132.79	9,452	17,310,678
Sep-05	14,535,597	33	26	1	30	133.09	9,460	13,265,753
Oct-05	13,359,593	234	8	1	31	133.38	9,467	13,654,663
Nov-05	13,515,784	396	-	1	30	133.68	9,467	13,396,996
Dec-05	15,642,297	689	-	-	31	133.98	9,469	15,572,194
Jan-06	14,831,647	555	-	-	31	134.25	9,489	15,206,208
Feb-06	13,693,984	603	-	-	28	134.53	9,523	14,033,615
Mar-06	14,234,656	530	-	1	31	134.81	9,525	14,315,115
Apr-06	12,480,967	315	-	1	30	135.08	9,530	13,239,120
May-06	13,391,623	156	22	1	31	135.36	9,543	14,065,204
Jun-06	15,047,749	27	43	-	30	135.64	9,544	14,867,535
Jul-06	19,026,240	2	136	-	31	135.92	9,551	18,664,720
Aug-06	17,271,942	8	70	-	31	136.20	9,560	16,272,863
Sep-06	13,597,770	105	4	1	30	136.48	9,575	12,835,983
Oct-06	13,918,242	304	-	1	31	136.76	9,589	13,736,249
Nov-06	14,040,974	393	-	1	30	137.04	9,598	13,555,478
Dec-06	15,474,866	508	-	-	31	137.33	9,599	15,211,047

	Purchased	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	Ontario Real GDP Monthly %	Customer	Predicted Purchases
Jan-07	15,702,988	666	-	-	31	137.55	9,605	15,678,677
Feb-07	14,969,307	762	-	-	28	137.78	9,603	14,600,429
Mar-07	14,984,498	565	-	1	31	138.01	9,605	14,519,231
Apr-07	13,573,714	374	-	1	30	138.23	9,606	13,510,534
May-07	13,586,565	138	23	1	31	138.46	9,623	14,150,778
Jun-07	16,499,886	19	74	-	30	138.69	9,640	16,105,989
Jul-07	16,698,025	9	82	-	31	138.92	9,657	16,836,947
Aug-07	17,984,840	8	106	-	31	139.15	9,667	17,727,965
Sep-07	14,762,955	55	37	1	30	139.38	9,721	14,091,136
Oct-07	14,023,826	158	13	1	31	139.61	9,742	13,981,985
Nov-07	14,013,283	468	-	1	30	139.84	9,763	13,984,132
Dec-07	15,868,249	644	-	-	31	140.07	9,789	15,850,158
Jan-08	15,764,852	633	-	-	31	139.97	9,806	15,840,106
Feb-08	14,902,959	679	-	-	29	139.86	9,810	15,075,444
Mar-08	15,024,634	621	-	1	31	139.76	9,810	14,944,229
Apr-08	12,928,634	288	-	1	30	139.65	9,826	13,539,485
May-08	13,093,339	213	0	1	31	139.55	9,840	13,803,073
Jun-08	15,634,588	34	55	-	30	139.44	9,855	15,720,801
Jul-08	17,769,759	4	88	-	31	139.34	9,858	17,287,521
Aug-08	16,451,327	20	45	-	31	139.23	9,860	15,778,973
Sep-08	14,772,756	70	20	1	30	139.13	9,869	13,705,082
Oct-08	14,010,438	298	-	1	31	139.02	9,875	14,083,377
Nov-08	14,578,065	461	-	1	30	138.92	9,883	14,117,717
Dec-08	16,663,518	655	-	-	31	138.81	9,937	16,073,931
Jan-09	17,050,345	852	-	-	31	138.39	9,943	16,656,912
Feb-09	14,445,284	617	-	-	28	137.97	9,947	14,617,111
Mar-09	14,873,166	541	-	1	31	137.54	9,956	14,897,943
Apr-09	13,253,480	335	-	1	30	137.13	9,955	13,842,295
May-09	13,056,803	178	-	1	31	136.71	9,966	13,851,278
Jun-09	14,334,094	59	30	-	30	136.29	9,967	15,025,355
Jul-09	15,527,173	19	22	-	31	135.87	9,989	15,078,244
Aug-09	17,690,606	18	70	-	31	135.46	9,995	16,844,680
Sep-09	14,455,746	68	12	1	30	135.05	10,008	13,585,720
Oct-09	14,130,993	260	3	1	31	134.63	10,041	14,281,091
Nov-09	14,175,811	425	-	1	30	134.22	10,055	14,232,986
Dec-09	16,626,564	614	-	-	31	133.81	10,073	16,128,590
Jan-10	16,710,571	729	-	-	31	134.17	10,076	16,466,356
Feb-10	14,688,782	618	-	-	28	134.52	10,094	14,810,693
Mar-10	14,685,369	457	-	1	31	134.87	10,107	14,845,797
Apr-10	13,053,838	236	1	1	30	135.23	10,110	13,781,406
May-10	14,445,331	128	29	1	31	135.58	10,117	14,956,241
Jun-10	16,128,917	27	45	-	30	135.94	10,131	15,679,718
Jul-10	19,784,906	6	121	-	31	136.30	10,134	18,879,711
Aug-10	19,044,590	7	96	-	31	136.65	10,148	17,958,237
Sep-10	14,895,980	97	22	1	30	137.01	10,166	14,215,205
Oct-10	13,951,925	261	-	1	31	137.37	10,176	14,361,821
Nov-10	14,495,200	417	-	1	30	137.73	10,215	14,414,266
Dec-10	17,057,264	696	-	-	31	138.10	10,231	16,570,021

	Purchased	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	Ontario Real GDP Monthly %	Customer	Predicted Purchases
Jan-11		726	-	-	31	138.35	10,244	16,672,245
Feb-11		633	-	-	28	138.60	10,257	15,062,333
Mar-11		551	-	1	31	138.85	10,270	15,328,145
Apr-11		328	1	1	30	139.10	10,283	14,269,451
May-11		172	11	1	31	139.35	10,296	14,676,787
Jun-11		38	58	-	30	139.61	10,308	16,407,450
Jul-11		7	100	-	31	139.86	10,321	18,345,777
Aug-11		11	79	-	31	140.11	10,334	17,592,758
Sep-11		72	27	1	30	140.37	10,347	14,551,655
Oct-11		260	3	1	31	140.62	10,360	14,694,574
Nov-11		413	-	1	30	140.88	10,373	14,605,566
Dec-11		633	-	-	31	141.13	10,386	16,583,079
Jan-12		726	-	-	31	141.42	10,399	16,870,703
Feb-12		633	-	-	29	141.72	10,412	15,712,997
Mar-12		551	-	1	31	142.01	10,425	15,526,602
Apr-12		328	1	1	30	142.30	10,438	14,467,909
May-12		172	11	1	31	142.59	10,450	14,875,245
Jun-12		38	58	-	30	142.89	10,463	16,605,908
Jul-12		7	100	-	31	143.18	10,476	18,544,234
Aug-12		11	79	-	31	143.48	10,489	17,791,215
Sep-12		72	27	1	30	143.77	10,502	14,750,113
Oct-12		260	3	1	31	144.07	10,515	14,893,031
Nov-12		413	-	1	30	144.37	10,528	14,804,024
Dec-12		633	-	-	31	144.66	10,541	16,781,537

Exhibit 4 Operating Costs

MANAGERS SUMMARY

The operating costs presented in this Exhibit represent the annual expenditures required to sustain Grimsby Power Inc.'s distribution operations. Grimsby Power Inc. follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of Grimsby Power Inc.'s operating costs for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, the 2012 (CGAAP) Test Year, and 2012 (IFRS) Test Year in accordance with the Filing Requirements is provided. The Boards Chapter 2 Appendix 2-E is shown below as Table 4.1 which shows the variances and totals. The Boards Chapter 2 Appendix 2-I is shown below as Table 4.2 which shows the OM&A Cost per Customer and per FTEE.

Table 4.1 Summary of OM&A Expenses and Year over Year Comparisons (Board Appendix 2-E)

	2006	2006	Variance	Percentage Change
	Board-approved	Actuals	$	%
Operations	$ 207,528	$ 187,438	-$ 20,090	-9.68%
Maintenance	$ 219,107	$ 225,316	$ 6,209	2.83%
Billing and Collecting	$ 399,757	$ 407,642	$ 7,885	1.97%
Community Relations	$ 5,388	$ 53,288	$ 47,900	889.01%
Administrative and General	$ 719,186	$ 635,882	-$ 83,304	-11.58%
Total OM&A Expenses	$ 1,550,966	$ 1,509,565	-$ 41,401	-2.67%
				1.90%

	2006	2007	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 187,438	$ 187,089	-$ 349	-0.19%
Maintenance	$ 225,316	$ 271,420	$ 46,105	20.46%
Billing and Collecting	$ 407,642	$ 483,317	$ 75,676	18.56%
Community Relations	$ 53,288	$ 80,754	$ 27,466	51.54%
Administrative and General	$ 635,882	$ 695,452	$ 59,570	9.37%
Total OM&A Expenses	$ 1,509,565	$ 1,718,034	$ 208,468	13.81%
Inflation Rate				2.10%

	2007	2008	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 187,089	$ 200,472	$ 13,383	7.15%
Maintenance	$ 271,420	$ 409,935	$ 138,515	51.03%
Billing and Collecting	$ 483,317	$ 487,755	$ 4,438	0.92%
Community Relations	$ 80,754	$ 33,426	-$ 47,328	-58.61%
Administrative and General	$ 695,452	$ 661,546	-$ 33,906	-4.88%
Total OM&A Expenses	$ 1,718,034	$ 1,793,136	$ 75,102	4.37%
Inflation Rate				2.30%

	2008	2009	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 200,472	$ 197,350	-$ 3,122	-1.56%
Maintenance	$ 409,935	$ 380,246	-$ 29,689	-7.24%
Billing and Collecting	$ 487,755	$ 463,965	-$ 23,791	-4.88%
Community Relations	$ 33,426	$ 11,428	-$ 21,999	-65.81%
Administrative and General	$ 661,546	$ 717,486	$ 55,939	8.46%
Total OM&A Expenses	$ 1,793,136	$ 1,770,474	-$ 22,662	-1.26%
Inflation Rate				1.30%

	2009 Actuals	2010 Actuals	Variance $	Percentage Change %
Operations	$ 197,350	$ 179,324	-$ 18,026	-9.13%
Maintenance	$ 380,246	$ 397,852	$ 17,606	4.63%
Billing and Collecting	$ 463,965	$ 506,789	$ 42,825	9.23%
Community Relations	$ 11,428	$ 11,749	$ 322	2.81%
Administrative and General	$ 717,486	$ 710,002	-$ 7,483	-1.04%
Total OM&A Expenses	$ 1,770,474	$ 1,805,717	$ 35,243	1.99%
Inflation Rate				1.30%

	2010 Actuals	2011 Actuals	Variance $	Percentage Change %
Operations	$ 179,324	$ 271,866	$ 92,542	51.61%
Maintenance	$ 397,852	$ 418,385	$ 20,533	5.16%
Billing and Collecting	$ 506,789	$ 504,524	-$ 2,265	-0.45%
Community Relations	$ 11,749	$ 16,500	$ 4,751	40.43%
Administrative and General	$ 710,002	$ 869,244	$ 159,242	22.43%
Total OM&A Expenses	$ 1,805,717	$ 2,080,519	$ 274,802	15.22%
Inflation Rate				

	2011 Actuals	CGAAP 2012 Forecast	Variance $	Percentage Change %
Operations	$ 271,866	$ 283,721	$ 11,855	4.36%
Maintenance	$ 418,385	$ 489,114	$ 70,729	16.91%
Billing and Collecting	$ 504,524	$ 590,270	$ 85,746	17.00%
Community Relations	$ 16,500	$ 12,500	-$ 4,000	-24.24%
Administrative and General	$ 869,244	$ 1,084,372	$ 215,128	24.75%
Total OM&A Expenses	$ 2,080,519	$ 2,459,977	$ 379,458	18.24%

Table 2: Additional Total OM&A Expense Comparative Information Table

Required Total OM&A Comparison

	2010 Actuals	2012 IFRS Forecast	Variance $	Percentage Change %
Test Year versus Most	$ 1,805,717	$ 2,623,797	$ 818,080	45.31%
	2006 Board-approved	**2012 Forecast**	**Variance $**	**Percentage Change %**
Test Year versus LRY Board-	$ 1,550,966	$ 2,623,797	$ 1,072,831	69.17%
Simple average of % variance for all years				6.80%
Compound annual growth rate for all years				11.09%

Table 4.2 OM&A Cost per Customer and per FTEE (Board Appendix 2-I)

	2006 - Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 CGAAP Test Year	2012 IFRS Test Year
Number of Customers	11,915	9,468	9,584	9,768	9,909	10,062	10,272	10,486	10,486
Total OM&A from Appendix 2-G		$ 1,509,565	$ 1,718,034	$ 1,793,136	$ 1,770,474	$ 1,805,717	$ 2,080,519	$ 2,459,977	$ 2,623,797
OM&A cost per customer	$ -	$ 159.44	$ 179.26	$ 183.57	$ 178.67	$ 179.46	$ 202.54	$ 234.60	$ 250.22
Number of FTEEs		14.5	14.5	15.5	15.5	16.5	17.5	18.5	18.5
Customers/FTEEs		652.97	660.97	630.19	639.29	609.82	586.97	566.81	566.81
OM&A Cost per FTEE		$ 104,107.96	$ 118,485.10	$ 115,686.22	$ 114,224.11	$ 109,437.40	$ 118,886.78	$ 132,971.73	$ 141,826.86

The number of customers includes the average number of residential, GS<50 and GS>50 customers as found in Grimsby Power Inc's Load Forecast.

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided later in this Exhibit.

OM&A Costs

OM&A costs in this Exhibit represent Grimsby Power Inc.'s integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives, to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to Grimsby Power Inc.'s distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2012 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate cost effective solutions are put in place.

Grimsby Power Inc. is proposing recovery of 2012 Test Year OM&A costs, excluding amortization, PILs and interest totaling $2,623,797.

OM&A Budgeting Process Used by Grimsby Power Inc.

The annual budget process was revised in 2010 and utilizes a bottom up approach to creating a budget. Budgets for 2011 and 2012 were created using this new process. This approach builds from all known costs and adds in costs for all identified tasks, activities and projects which were not previously detailed at the task or activity level. The operating budget is intended to be prepared annually by management and is reviewed and approved by the Grimsby Power Inc. Board. The budget is prepared before the start of each fiscal year, and provides a plan against which actual results may be measured and analyzed. Once approved, the budget is only revised if a material change in plan is required. All material changes would be subject to Grimsby Power Inc. Board approval.

The operating budget is a component of the overall budget process described in Exhibit 1.

Operating Work Plans

Each Department Manager provides detailed input for the preparation of the budget. The following directives are provided to each department head:

- Outside expenses for all tasks, activities, and projects are built using previous year actual, current year forecast or current year budget as the base;
- Significant variances in spending from prior years must be explained and documented;
- Review the headcount of the department for accuracy and outline any proposed changes;
- The total labor budget using projected wage and benefit cost are built into the budget model (excel spreadsheet). Overtime and the distribution of total hours are based on previous years actual plus any identified changes for the future year.

Income Tax, Large Corporation tax and Ontario Capital Taxes

Grimsby Power Inc. is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Please refer to Tables 4.33 & 4.34 for further tax calculations and a copy of Grimsby Power Inc.'s tax returns in Appendix 4.1.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITES

Operations & Maintenance

The expenses for these activities include all costs relating to the operation (5000-5095) and maintenance (5105-5195) of Grimsby Power Inc.'s electrical distribution system. This includes both direct labor costs and non-capital material spending to support Grimsby Power Inc.'s Inspection and Maintenance Program as well as unplanned, planned, and emergency work. From 2006 to 2011 expenses were allocated from support departments to cover the expenses of Labour Burden, Engineering and Stores. As a result of IFRS the extent of the allocations has been changed to reflect the new IFRS standards. Grimsby Power Inc.'s maintenance strategy is, to the extent possible, to minimize unplanned and emergency-type work through an effective planned maintenance program (including predictive and preventative actions). Grimsby Power Inc.'s Inspection and Maintenance Program is included in its Distribution Asset Management Plan (DAMP) which is contained in this application. Since the last rebasing in 2006, Grimsby Power's Inspection and Maintenance program has been focused on tree clearing (maintaining tree clearances to overhead plant), overhead inspection patrols, pad-mounted equipment inspection patrols, and maintaining items (in priority sequence) identified by these patrols as a risk to the public.

Grimsby Power Inc.'s customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with Grimsby Power Inc.'s capital project work so that items identified in the inspection/patrol program are corrected with the appropriate capital investment. Grimsby Power Inc. may adjust its capital spending priorities to address those matters.

Predictive Maintenance

Predictive maintenance activities involve the testing of elements of Grimsby Power Inc.'s distribution system. These activities include substation transformer oil analysis, planned visual inspections and pole testing. These evaluation tools are all administered using a grid system with appropriate frequency levels. Any identified deficiencies found are prioritized and addressed within a suitable time frame.

Preventative Maintenance

Preventative maintenance activities include inspection, servicing and repair of distribution system components. This includes overhead and pad-mounted load break switch maintenance and pad-mounted transformer maintenance. Also included are regular inspection and repair of substation components and ancillary equipment. The work is performed using a combination of time and condition based methodologies.

Emergency Maintenance

This item includes unexpected system repairs to the electrical system that must be addressed immediately. The costs include repairs to distribution assets caused by storms (wind, rain, lightning, snow, ice, etc.), tree contacts, animal contacts, and general equipment failures on the distribution system. Grimsby Power Inc. constantly evaluates its maintenance data to adjust predictive and preventative actions. The ultimate objective is to reduce this emergency maintenance. An answering service company has been contracted to contact "on call" lineperson and supervisory staff in the event of service problems outside of normal business hours.

Service Work

The majority of costs related to this work pertain to service upgrades and repairs requested by customers. This includes service disconnections and reconnections by Grimsby Power Inc. for all service classes; assisting pre-approved contractors; the making of final connections after Electrical Safety Authority ("ESA") inspection for service upgrades; and changes of service locations.

Metering

The Grimsby Power Inc. metering technicians (Metering) are part of the Engineering and Operations Department. They are responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter settings for billing purposes.

Revenue protection is another key activity performed by Metering, by proactively investigating potential diversion and theft of power. This is performed in conjunction with local law enforcement agencies.

Distribution Substation Services

Substation services are managed by the Operations Supervisor and address the maintenance of all equipment at Grimsby Power Inc.'s two distribution substations. This includes both labor costs, non-capital material spending, and third party services to support both scheduled and emergency maintenance events. Grimsby Power Inc.'s substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of Grimsby Power Inc.'s planned maintenance program (including predictive and preventative actions) for its substations.

ENGINEERING DEPARTMENT

The Engineering Department is responsible for all distribution system design and keeping accurate distribution system asset related data. This is accomplished by utilizing a Geographic Information System ("GIS") and various data bases in MS Access format. The GIS system is used for asset management activities, mapping the distribution system, troubleshooting system problems, delivering underground utility locating services for excavating contractors and for design and construction activities including new capital projects and customer connections. Engineering provides distribution system asset information to Grimsby Power Inc.'s various departments. Prior to IFRS Engineering expenses were allocated to operations, maintenance, and capital accounts based on percentage splits between accounts. This allocation of costs is performed on a monthly basis and adjusted to actual at year end. The 2011 budget process as described earlier required expenses which could be attributed to a specific account (as opposed to an allocation account) to be directly accounted for. With the implementation of IFRS Engineering expenses previously allocated in the 2012 Test Year budget have been transferred to account 5085 thus eliminating the allocation methodology for Engineering expenses.

STORES / WAREHOUSE

The Finance Department is responsible and accountable for managing the procurement, control, and movement of materials as it flows from receipt to issuance and supports the design/construct process. This would include monitoring inventory levels, receiving goods upon delivery (issuing material receipts), material issues, and material returns as required. Prior to IFRS Stores expenses were allocated to operations, maintenance, and capital accounts based on percentage splits between accounts. This allocation of expenses is performed on a monthly basis and adjusted to actual at year end. The 2011 budget process as described earlier required expenses which could be attributed to a specific account (as opposed to an allocation account) to be directly accounted for. With the implementation of IFRS Stores expenses previously allocated in the 2012 Test Year budget have been transferred to account 5085 thus eliminating the allocation methodology for Stores expenses.

FLEET

The Operations Department is responsible and accountable for the maintenance and control of approximately eight fleet vehicles and associated equipment. Its objectives include organizing maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle down time. Prior to IFRS fleet expenses were allocated to operations, maintenance, and capital accounts based on the number of hours used. A standard hourly cost/hr is set for all vehicles within the fleet. Expenses are adjusted to actual at year end. With the implementation of IFRS some fleet expenses previously allocated in the 2012 Test Year budget have been transferred to account 5085.

HEALTH AND SAFETY

For the years from 2006 to 2011 expenses related to health & safety were allocated to all operations, maintenance and capital accounts. As a result of a new budgeting process and IFRS, health & safety expenses are allocated directly to the appropriate OM&A account.

Grimsby Power Inc. does not employ (on staff) a specific Health and Safety professional or have a specific department in charge of Health and Safety. Instead, the responsibility of Health and Safety is delegated to each department manager.

The Internal Responsibility System (IRS) is paramount in the execution of Grimsby Power Inc.'s Health and Safety Management System.

Grimsby Power Inc. is committed to maximizing productivity and reducing the risk of injury. This is accomplished by executing a health & safety management program that promotes preventative (rather than reactive) actions. The commitment to health & safety is significant, and involves documenting unsafe behaviors, monitoring conformance to established standards and policies, determining the effectiveness of safety training and monitoring the resolution of safety recommendations/audits; commitment to continuous improvement in training; and identifying and correcting root causes for system deficiencies. Grimsby Power Inc. has achieved the Bronze Medal for safety by the former E&USA, (health & safety delivery agency) currently the IHSA (Infrastructure Health & Safety Association) in the quest for zero lost time injuries.

CUSTOMER ACCOUNTS

The Customer Accounts department is responsible and accountable for the customer care activities for customers in Grimsby Power Inc.'s service area. These activities include billing, call centre, collections, meter reading, and other back office functions. Grimsby Power Inc. aspires to achieve customer service excellence in its processes and customer programs. The expenses associated with the Customer Accounts department are collected in accounts 5305 to 5340.

Meter Reading

Meter reading services are contracted out to a non-affiliated third party under a service contract agreement. On average, the contractor reads 10,125 (December 31, 2010) electric service meters per month. With the installation of Smart Meters this agreement operates on a month to month basis and is intended to be phased out in mid 2011. This phase out is dependent on the efficiency of the data transmission (target is 98%) within the smart meter system (meter to tower to advanced control computer to operational data store). The 2011 budget reflects only 6 months of manual meter reading expenses and it is expected that the Operational Data Store and the MDMR will be utilized in place of manual meter reading as these systems come on line in 2011. The 2012 budget contains expenses for a check read of all meters once in the calendar year. There is a small percentage of customers in the GS>50 rate class (approximately 72) which will require ongoing reading. The means to read these meters is still being assessed.

Billing

Grimsby Power Inc. performs monthly billing and issues approximately 121,729 electricity invoices annually to customers. On average this total includes approximately 1327 final bills for customers moving within or outside of Grimsby Power Inc.'s service territory. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. With the advent of Time of Use (TOU) billing the billing schedule is being modified to maximize business processes. The billing functions include the VEE processes; EBT and retailer settlement functions for approximately 1398 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. Grimsby Power Inc. offers customers a number of billing and payment options including walk in counter service (not including bill payment), an equal payment plan, a preauthorized payment plan, and payment by credit card through the Paymentis system.

Collections

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. In an effort to minimize credit losses, Grimsby Power Inc.

enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. Final bill collections are turned over to a collection agency after collection methods are exhausted.

Community Relations

Grimsby Power Inc. is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. Grimsby Power Inc. maintains a presence in the community it serves and staff is available to answer customer questions in a friendly environment.

Since LDCs are the “face-to-the-customer” for the electricity industry, Grimsby Power Inc. has an important role to play in educating the public about electricity safety and energy conservation. Grimsby Power Inc. continues to participate with the OPA in administering programs directed at Energy Conservation. Grimsby Power Inc. is very active in the community promoting conservation initiatives, attending a number of community events each year, distributing energy efficient electric devices and energy conservation information. These conservation activities are funded by the OPA.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Consistent with Section 6-4 of the 2007 EDR Handbook which states “For an applicant with fewer than three employees, reporting of employee compensation under this section is not required In cases where there are three or fewer, full time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer FTEs.” Grimsby Power Inc. has aggregated accounts 5605 and 5610 with account 5615. In 2011 a number of changes were made to the accounts utilized by Grimsby Power Inc. and the information noted below reflects practices put in place starting in 2011.

Executive Salaries and Expenses 5605

This account includes expenses for the Chief Executive Officer including salaries and related expenses. As there is only 1 FTE in this category this account has been aggregated into account 5615.

Management Salaries and Expenses 5610

This account includes expenses for the Director of Finance and the Director of Engineering including salaries and related expenses. As there are only 2 FTE's in this category this account has been aggregated into account 5615.

General Administrative Services and Expenses 5615

Consistent with the notations under accounts 5605 and 5610 the General Administrative Services and Expenses account includes the Executive team and the Finance Department. The positions of CEO, Director of Engineering & Operations, Director of Finance, and the Executive Assistant include a wide range of responsibilities which together cross all functional areas of the corporation.

The Director of Engineering & Operations is responsible for the Distribution Asset Management Plan, Engineering Design, Metering, Graphic Information System (GIS), Information Technology (IT) and Operations.

The Executive Assistant is responsible for providing support services required to operate an effective corporation including human resource-related support services (payroll, benefit administration, collective agreement negotiation, etc.), corporate governance services, and Board of Director support.

The Finance Department under the direction of the Director of Finance is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with GAAP (and IFRS as of 2012); all daily accounting functions, including accounts payable, accounts receivable, and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. The department is also responsible for all regulatory reporting and compliance with applicable codes and legislation governing Grimsby Power Inc. including development and preparation of rate filings, performance reporting, and compliance.

Expenses included in General Administrative Services and Expenses also include salary and related payroll burdens associated with the Accounting Assistant, the Wholesale and Retail Settlement Officer, and the Financial & Regulatory Analyst as well as incidental expenses relating to corporate services support and human resource support.

Office Supplies and Expenses 5620

Office Supplies and Expenses includes, but are not limited to, meals, travel, incidentals, lease payments for office equipment, fixed and mobile phone services, memberships, employee recognition programs, and general office supplies.

Outside Service Employed 5630

Outside Services Employed include, but are not limited to, consulting and professional fees of accountants, auditors, legal services, tax consultants, engineering auditors, health and safety auditors, health & safety program facilitators, and human resource professionals.

Property Insurance 5635

Property Insurance includes insurance on all property of Grimsby Power Inc.

Employee Post-Retirement Benefits 5645

Employee Post-Retirement Benefits include annual expenses for post-retirement benefits provided to eligible Grimsby Power Inc. employees (retired employees) in accordance with company policy.

Regulatory Expenses 5655

Regulatory Expenses include those expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to the OEB. Third party service costs to prepare annual rate applications are also included.

Miscellaneous General Expense 5665

Miscellaneous General Expenses include Membership dues and Board of Directors fees and expenses. Grimsby Power Inc. is a member of the Electrical Distributor Association (EDA). Through our membership with the EDA, LDC's have promoted a unified voice to various regulatory bodies and the Ministry of Energy.

Maintenance of General Plant 5675

Expenses under Maintenance of General Plant include all costs of operating the service centre/office building. These include items such as: building utility costs, maintenance & repairs to the building/land, grounds maintenance, and services associated with the operation of the computer network including burdened salaries for the Engineering Technician who performs IT functions.

Electrical Safety Authority ("ESA") 5680

Expenses under Electrical Safety Authority ("ESA") fees include all annual charges from the ESA.

DETAILED OM&A EXPENSE TABLES (BOARD APPENDIX 2-F)

Tables 4.3 through 4.7 provide detailed breakdowns of costs in the various OM&A accounts.

Table 4.3 Detailed Account by Account Operation Expenses

Account	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 CGAAP Test	2012 IFRS Test
Operations									
5005	Operation Supervision and Engineering	$ 13,468	$ 22,491	$ 25,442	$ 22,962	$ 24,379	$ 63,825	$ 60,649	$ 60,649
5012	Station Buildings and Fixtures Expense	$ 1,784	$ 2,680	$ 4,244	$ 340	$ 775	$ -	$ -	$ -
5020	Overhead Distribution Lines and Feeders - Ope	$ 37,049	$ 45,511	$ 60,675	$ 55,554	$ 68,827	$ 28,427	$ 38,630	$ 37,599
5025	Overhead Distribution Lines and Feeders - Ope	$ 19,265	$ 20,809	$ 22,106	$ 19,133	$ 16,330	$ 9,650	$ 12,928	$ 12,010
5035	Overhead Distribution Transformers - Operation	$ 5,045	$ 1,132	$ 4,437	$ 712	$ 2,031	$ -	$ -	$ -
5040	Underground Distribution Lines and Feeders - O	$ 39,275	$ 37,010	$ 30,904	$ 37,269	$ 29,597	$ 32,874	$ 35,403	$ 31,158
5045	Underground Distribution Lines and Feeders - O	$ 36	$ 1,334	$ 729	$ 210	$ 62	$ -	$ -	$ -
5055	Underground Distribution Transformers - Operat	$ 1,294	$ 2,659	$ 1,115	$ 57	$ -	$ -	$ -	$ -
5065	Meter Expense	$ 33,901	$ 14,082	$ 15,944	$ 23,875	$ 6,645	$ -	$ -	
5070	Customer Premises - Operation Labour	$ 5,243	$ 12,700	$ 8,203	$ 8,048	$ 8,307	$ 4,687	$ 5,383	$ 4,701
5075	Customer Premises - Operation Materials and	$ 35	$ 10	$ -	$ -	$ 123	$ -	$ -	$ -
5085	Miscellaneous Distribution Expenses	$ 18,144	$ -	$ 13,774	$ 16,291	$ 12,572	$ 106,903	$ 104,970	$ 306,291
5095	Overhead Distribution Lines and Feeders - Ren	$ 12,900	$ 26,672	$ 12,900	$ 12,900	$ 9,675	$ 25,500	$ 25,758	$ 25,758
Total - Operations		$ 187,438	$ 187,089	$ 200,472	$ 197,350	$ 179,324	$ 271,866	$ 283,721	$ 478,166

Table 4.4 Detailed Account by Account Maintenance Expenses

Account	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 CGAAP Test	2012 IFRS Test
Maintenance									
5105	Maintenance Supervision and Engineering	$ 19,823	$ 24,781	$ 35,678	$ 31,818	$ 33,342	$ 55,325	$ 51,441	$ 51,441
5114	Maintenance of Distribution Station Equipment	$ 2,951	$ 5,882	$ 3,697	$ 1,575	$ 2,027	$ 800	$ 816	$ 816
5120	Maintenance of Poles, Towers and Fixtures	$ 37,882	$ 39,055	$ 47,202	$ 35,802	$ 69,241	$ 64,082	$ 43,421	$ 40,114
5125	Maintenance of Overhead Conductors and Devi	$ 58,353	$ 41,876	$ 72,404	$ 72,129	$ 79,075	$ 99,159	$ 90,730	$ 82,836
5130	Maintenance of Overhead Services	$ 33,216	$ 36,780	$ 50,945	$ 54,578	$ 57,337	$ 40,193	$ 75,842	$ 67,233
5135	Overhead Distribution Lines and Feeders - Righ	$ 39,542	$ 51,377	$ 59,110	$ 69,375	$ 51,225	$ 40,268	$ 77,873	$ 77,653
5145	Maintenance of Underground Conduit	-$ 623	$ 132	$ 646	$ 8,196	-$ 76			
5150	Maintenance of Underground Conductors and D	$ 402	$ 16,997	$ 15,241	$ 3,003	$ 24,137			
5155	Maintenance of Underground Services	$ 9,725	$ 12,812	$ 17,825	$ 12,685	$ 8,750	$ 11,162	$ 15,029	$ 13,817
5160	Maintenance of Line Transformers	$ 23,619	$ 40,516	$ 101,294	$ 83,405	$ 63,243	$ 93,164	$ 85,784	$ 78,586
5175	Maintenance of Meters	$ 425	$ 1,212	$ 5,894	$ 7,680	$ 9,550	$ 14,232	$ 48,178	$ 48,178
Total - Maintenance		$ 225,316	$ 271,420	$ 409,935	$ 380,246	$ 397,852	$ 418,385	$ 489,114	$ 460,674

Table 4.5 Detailed Account by Account Billing and Collecting Expenses

Account	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 CGAAP Test	2012 IFRS Test
Billing and Collecting									
5305	Supervision	$ 8,214	$ 10,000	$ 9,228	$ 14,328	$ 9,824	$ 4,660	$ 4,284	$ 4,284
5310	Meter Reading Expense	$ 111,485	$ 106,073	$ 113,978	$ 100,061	$ 172,730	$ 87,665	$ 168,662	$ 166,644
5315	Customer Billing	$ 253,712	$ 308,072	$ 303,930	$ 298,993	$ 264,282	$ 357,358	$ 360,711	$ 360,711
5320	Collecting	$ 62,378	$ 58,275	$ 59,514	$ 54,583	$ 55,130	$ 42,935	$ 43,983	$ 43,983
5325	Collecting - Cash Over and Short	$ 0	-$ 243	-$ 63	-$ 70	$ 70	$ -	$ -	$ -
5330	Collection charges					$ 573	$ 5,906	$ 6,630	$ 6,630
5335	Bad Debt Expense	-$ 28,147	$ 1,140	$ 1,167	-$ 3,931	$ 4,180	$ 6,000	$ 6,000	$ 6,000
Total - Billing and Collecting		$ 407,642	$ 483,317	$ 487,755	$ 463,965	$ 506,789	$ 504,524	$ 590,270	$ 588,252

Table 4.6 Detailed Account by Account Community Relations Expenses

Account	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 CGAAP Test	2012 IFRS Test
Community Relations									
5410	Community Relations - Sundry	$ 10,846	$ 11,670	$ 11,836	$ 11,428	$ 11,649	$ 12,000	$ 9,000	$ 9,000
5415	Energy Conservation	$ 41,058	$ 67,080	$ 19,894	$ -	$ -	$ -	$ -	$ -
5515	Advertising Expenses	$ 1,384	$ 2,004	$ 1,696		$ 100	$ 4,500	$ 3,500	$ 3,500
Total - Community Relations		$ 53,288	$ 80,754	$ 33,426	$ 11,428	$ 11,749	$ 16,500	$ 12,500	$ 12,500

Table 4.7 Detailed Account by Account General & Administrative Expenses

Account	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 CGAAP Test	2012 IFRS Test
Administrative and General Expenses									
5615	General Administrative Salaries and Expenses	$ 367,268	$ 480,355	$ 481,750	$ 469,117	$ 465,175	$ 528,970	$ 614,579	$ 614,579
5620	Office Supplies and Expenses	$ 43,289	$ 46,507	$ 47,473	$ 39,985	$ 42,000	$ 32,325	$ 44,861	$ 44,694
5630	Outside Services Employed	$ 86,805	$ 44,396	$ 12,131	$ 52,577	$ 43,503	$ 47,920	$ 86,856	$ 86,856
5635	Property Insurance	$ 4,139	$ 4,323	$ 4,107	$ 8,373	$ 8,642	$ 22,000	$ 23,307	$ 23,307
5640	Injuries and Damages	$ 16,732	$ 18,121	$ 18,631	$ 16,794	$ 13,144	$ -	$ -	$ -
5645	Employee Pensions and Benefits						$ 5,880	$ 5,998	$ 5,998
5655	Regulatory Expenses	$ 33,993	$ 24,865	$ 23,361	$ 25,722	$ 26,173	$ 26,500	$ 59,520	$ 59,520
5665	Miscellaneous General Expenses				$ 19,705	$ 21,455	$ 88,790	$ 99,401	$ 99,401
5675	Maintenance of General Plant	$ 42,818	$ 40,438	$ 42,334	$ 50,172	$ 60,004	$ 80,885	$ 113,093	$ 113,093
5680	Electrical Safety Authority Fees	$ 4,351	$ 4,458	$ 4,609	$ 4,726	$ 4,777	$ 5,000	$ 5,100	$ 5,100
Total - Administrative and General Expenses		$ 599,394	$ 663,462	$ 634,397	$ 687,172	$ 684,872	$ 838,270	$ 1,052,715	$ 1,052,548

Account	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 CGAAP Test	2012 IFRS Test
Taxe Other Than Income Taxes									
6105	Taxes Other Than Income Taxes	$ 36,488	$ 31,990	$ 27,150	$ 30,314	$ 25,130	$ 27,000	$ 27,540	$ 27,540
Total - Administrative and General Expenses		$ 36,488	$ 31,990	$ 27,150	$ 30,314	$ 25,130	$ 27,000	$ 27,540	$ 27,540

Account	Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 CGAAP Test	2012 IFRS Test
Other Deductions									
6205	Donations - LEAP program						$ 3,974	$ 4,117	$ 4,117
Total - Administrative and General Expenses		$ -	$ -	$ -	$ -	$ -	$ 3,974	$ 4,117	$ 4,117

COST DRIVERS

Grimsby Power Inc. has provided a detailed OM&A cost driver table (Table 4.8 below) covering the periods from 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and 2012 Test Year (closing balance) including the variances year over year. Before moving to a variance analysis for each account that exceeds the materiality threshold, a summary of total OM&A expenses is presented below along with an analysis of the total movement from 2006 Actual to 2012 Test Year (CGAAP).

Table 4.8 Cost Driver Table (Board appendix 2-G)

OM&A	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 CGAAP Test Year
Opening Balance	$ 1,550,966	$ 1,509,565	$ 1,718,034	$ 1,793,136	$ 1,770,474	$ 1,805,717	$ 2,080,519
(1) Staffing (Payroll and Benefits)	-$ 87,247	$ 133,453	$ 128,757	-$ 59,703	$ 159,224	$ 58,624	$ 130,663
(2) Change in Allocation Method						$ 139,820	$ 14,314
(3) Third Party Service Providers	$ 55,001	$ 35,049	-$ 22,795	$ 11,122	-$ 120,637	$ 12,744	$ 102,507
(4) Smart Meter System Costs							$ 129,960
(5) Computer Network and Website							$ 28,568
(6) Meter Maintenance						$ 52,500	-$ 31,922
(7) LEAP Program						$ 3,974	$ 143
(8) HST Saving							-$ 18,723
(9) Remaining Balance	-$ 9,155	$ 39,967	-$ 30,860	$ 25,920	-$ 3,344	$ 7,141	$ 23,948
Closing Balance	$ 1,509,565	$ 1,718,034	$ 1,793,135	$ 1,770,475	$ 1,805,716	$ 2,080,519	$ 2,459,977

Additional commentary is available in the variance analysis later in this exhibit.

Staffing (Payroll & Benefits)

Year over year changes in compensation and benefits reflects changes in employee compliment, wage increases, and increases in benefit costs. Decreases are reflective of the gaps in payroll during periods when one employee leaves and another is hired. The majority of increases are due to additions in employee compliment. Specific details are shown under “Employee Compensation and Benefits” in Table 4.25. The commentary later in this exhibit explains in detail year to year variances in terms of employee compliment, base wages, overtime and benefits by employee category.

Change in Allocation Method

For the determination of Grimsby Power Inc.’s 2011 budget, a new process was created to account for individual tasks, activities, and projects – a bottom up approach to budgeting. Along with this process, the allocation of expenses was realigned with the USofA accounts. One of the goals of the new process was to directly allocate identifiable work into its appropriate account as opposed to allocating costs over a number of accounts using mathematical calculations. Prior to 2011 costs associated with Stores, Engineering, and Operations Supervision was allocated to various Capital and OM&A accounts. The net difference between 2010 and 2012 Test Year (CGAAP) is an additional $154,135 booked to OM&A.

Third Party Service Providers

Grimsby Power Inc. utilizes a number of third party service providers as the need dictates. The Table 4.9 below highlights the details of year to year changes and summary explanations follow.

Table 4.9 Cost Drivers – Third Party Service Providers

	2006	2007	2008	2009	2010	2011 Bridge Year	2012 Test Year (CGAAP)
(3) Third Party Service Providers	**55,001**	**35,049**	**- 22,795**	**11,122**	**- 120,637**	**12,744**	**102,507**
FortisOntario (Financial Services)	15,213	- 15,213		-	-	-	-
Financial Audit Services	52,995	- 12,990	- 29,074	37,413	- 7,287	- 7,557	670
Canada Post	-	6,895	9,774	4,090	4,407	6,724	1,500
Line Contractor (Maintenance 5120 & 5125)	-	3,490	21,526	- 23,460	43,848	7,557	- 29,090
NPI Board Fees	-	34,537	83	- 33,453	- 54,525	- 11,000	-
NPI Management Fees		1,110	- 27,111	- 3,467	- 121,000		
Canadian Niagara Power (CIS Related Costs)	-	-	-	27,990	11,910	5,100	900
Health & Safety	-	-	-	-	-	11,920	11,336
Line Contractor (Maintenance 5160)							12,240
Process Meter Data							46,000
HR Consultant							26,880
Training							32,071

<u>FortisOntario (Financial Services)</u> – In 2006 turnover in the Finance Department created a number of months where there was no Department Head. FortisOntario provided assistance to bridge the gap between vacancies. The turnover is discussed in detail later in this exhibit.

<u>Financial Audit Services</u> - Increases and decreases can be explained by the activity in any given year as follows:

- *During 2006 extra audit work was required related to Grimsby Power Inc.'s rebasing application.*
- *In 2009 accounting methods were changed. Starting in 2009 expenses were booked using the accrual method of accounting. 2009 is higher because it includes expenses booked for the 2008 Audit plus accrual expenses for 2009's Audit.*

Canada Post – Increases in direct postage costs from 2006 have been fairly consistent year over year.

Line Contractor (Maintenance 5120, 5125, 5160) - The Line Contractor amounts vary from year to year depending on the volume of projects and the type of work accomplished. Expenses allocated to these accounts would generally be line transfers or removal work on large projects or emergency overflow work created as a result of storm restoration activity.

NPI Board Fees and NPI Management Fees - Fees charged from the holding company NPI to Grimsby Power Inc. fluctuated over the years dependent on staffing and activity levels. This is discussed in detail in this exhibit under the Shared Services discussion. These fees ended with the hiring of the CEO in February 2010.

Canadian Niagara Power (CIS Related Costs) - The installation of the new SAP customer information system (CIS) took place in 2009, adding to costs in this year. These costs represent approximately one half year of monthly fees. The increase in 2010 is attributed to a full year of monthly fees.

Health and Safety Facilitator – In 2011 Grimsby Power Inc. began utilizing a health and safety facilitator to raise the profile of health and safety within the organization. The facilitator provides quality health and safety meeting content and various training & evaluation activities.

Process Meter Data – GPI currently has a number of disparate systems and service providers which enable GPI to process meter data. This process includes the downloading of data from interval & wholesale meters, converting this data for use in the billing system, and comparing Grimsby Power Inc. data with IESO data in the settlement process. The net increase in costs is approximately $46,000 and includes a third party service to provide a consolidated end to end solution.

HR Consultant - In 2012 the collective agreement between Grimsby Power Inc. and the Power Workers Union will expire. Grimsby Power Inc. has budgeted professional services to assist with negotiations. In addition to this a review of compensation will be conducted.

Training – In 2012 Grimsby Power Inc. is planning in increasing its training program. Additional costs amount to $32,071.

Smart Meter System Costs

By the end of 2011 GPI will move to time-of-use pricing and as a result additional expenses are incurred. The Table 4.10 below highlights the details.

Table 4.10 Cost Drivers – Smart Meter System Costs

	2006	2007	2008	2009	2010	2011 Bridge Year	2012 Test Year (CGAAP)
(4) Smart Meter System Costs							**129,960**
MDMR							60,588
AMI Software Support							6,930
KTI/Sensus Meter Fees							30,618
KTI/Sensus TGB Fees							31,824

Computer Network and Website

Grimsby Power Inc. has an internal network of computer servers and associated work stations utilized by most staff. A network security audit has never been conducted and a risk assessment indicates that this network is critical to the operation of the utility. An audit will be conducted to ascertain the condition of the system and to recommend enhancements (if necessary). Grimsby Power Inc.'s website has not been updated in a number of years and does not incorporate today's functionality. A web site upgrade will take place in 2011 and future costs will be incurred to keep the website current. See Table 4.11 below for detail.

Table 4.11 Cost Drivers – Computer Network and Website

	2006	2007	2008	2009	2010	2011 Bridge Year	2012 Test Year (CGAAP)
(5) Computer Network & Web Site							**28,568**
Network Security Audit							10,000
Web Site Maintenance							10,000
Increase Internet Capacity							8,568

Meter Maintenance

The Operational Data Store (ODS) is required to facilitate the maintenance of smart meters and to enhance the operation of the utility by providing enhanced features not envisioned prior to the smart meter installation program. Grimsby Power Inc. has just recently went live with the system and is in the process of evaluating how the ODS will be utilized in the future. In addition to this costs incurred to convert existing customer premise meter bases to accommodate smart meters is included for 2011. In 2012 a web presentment tool is also incorporated into the budget which is new functionality to the smart meter system. See Table 4.12 below for detail.

Table 4.12 Cost Driver – Meter Maintenance & ODS Meter Fees

	2006	2007	2008	2009	2010	2011 Bridge Year	2012 Test Year (CGAAP)
(6) Meter Maintenance & ODS Meter Fees						**52,500**	- **31,922**
Meter Base Conversions						52,500	- 52,500
Web Presentment							4,200
Operational Data Store							16,378

LEAP Program

As per the OEB's report on Low-Income Energy Assistance Programs dated July 22, 2011, GPI anticipates spending $4,117 or 0.12% of its (anticipated) approved revenue requirement for the 2012 Test Year. This program was introduced in 2011.

HST Saving

As a result of the introduction of the HST on July 1, 2010, the OEB required utilities to calculate/estimate the savings incurred over the period from July 1, 2010 to December 31, 2011. Grimsby Power Inc. has estimated this amount to be $18,723.

Remaining Balance

This represents the difference between the sum of the identified cost drivers and difference between one year and the next.

VARIANCE ANALYSIS

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011, Grimsby Power Inc. has provided variance analyses for the 2012 Test Year vs. 2006 - Last Board-Approved Rebasing Application (Actual) and between the 2012 Test Year and 2010 Actual (Most Current Actual). Grimsby Power Inc. has reviewed the variance of each USoA account and provided explanations for variances exceeding a materiality threshold of $50,000. The variances are indicated in Table 4.13 below and an explanation of each variance is presented in the following section.

Table 4.13 Variance Analysis – OM&A Expenses (Board Appendix 2-J)

Account	Description	Last Board-approved Rebasing Year (2006 Actuals)	Most Current Actual Year (2010)	CGAAP Test Year (2012)	IFRS Test Year (2012)	2012 CGAAP Test Year Versus Last Rebasing (Actual)		2012 CGAAP Test Year Versus Most Current Actuals		2012 IFRS Test Year Versus CGAAP Test Year	
						Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Operations											
5005	Operation Supervision and Engineering	$ 13,468	$ 24,379	$ 60,649	$ 60,649	$ 47,181	350.33%	$ 36,270	148.77%	$ -	0.00%
5012	Station Buildings and Fixtures Expense	$ 1,784	$ 775	$ -	$ -	-$ 1,784	-100.00%	-$ 775	-100.00%	$ -	
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 37,049	$ 68,827	$ 38,630	$ 37,599	$ 1,581	4.27%	-$ 30,197	-43.87%	-$ 1,031	-2.67%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 19,265	$ 16,330	$ 12,928	$ 12,010	-$ 6,337	-32.89%	-$ 3,402	-20.83%	-$ 918	-7.10%
5035	Overhead Distribution Transformers - Operation	$ 5,045	$ 2,031	$ -	$ -	-$ 5,045	-100.00%	-$ 2,031	-100.00%	$ -	
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 39,275	$ 29,597	$ 35,403	$ 31,158	-$ 3,872	-9.86%	$ 5,806	19.62%	-$ 4,245	-11.99%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 36	$ 62	$ -	$ -	-$ 36	-100.00%	-$ 62	-100.00%	$ -	
5055	Underground Distribution Transformers - Operation	$ 1,294	$ -	$ -	$ -	-$ 1,294	-100.00%	$ -		$ -	
5065	Meter Expense	$ 33,901	$ 6,645	$ -	$ -	-$ 33,901	-100.00%	-$ 6,645	-100.00%	$ -	
5070	Customer Premises - Operation Labour	$ 5,243	$ 8,307	$ 5,383	$ 4,701	$ 140	2.67%	-$ 2,924	-35.20%	-$ 682	-12.67%
5075	Customer Premises - Operation Materials and Expenses	$ 35	$ 123	$ -	$ -	-$ 35	-100.00%	-$ 123	-100.00%	$ -	
5085	Miscellaneous Distribution Expenses	$ 18,144	$ 12,572	$ 104,970	$ 306,291	$ 86,826	478.54%	$ 92,398	734.95%	$ 201,321	191.79%
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 12,900	$ 9,675	$ 25,758	$ 25,758	$ 12,858	99.67%	$ 16,083	166.23%	$ -	0.00%
Total - Operations		$ 187,438	$ 179,324	$ 283,721	$ 478,166	$ 96,283	51.37%	$ 104,397	58.22%	$ 194,445	68.53%
Account	**Description**										
Maintenance											
5105	Maintenance Supervision and Engineering	$ 19,823	$ 33,342	$ 51,441	$ 51,441	$ 31,618	159.50%	$ 18,099	54.28%	$ -	0.00%
5114	Maintenance of Distribution Station Equipment	$ 2,951	$ 2,027	$ 816	$ 816	-$ 2,135	-72.35%	-$ 1,211	-59.74%	$ -	0.00%
5120	Maintenance of Poles, Towers and Fixtures	$ 37,882	$ 69,241	$ 43,421	$ 40,114	$ 5,539	14.62%	-$ 25,820	-37.29%	-$ 3,307	-7.62%
5125	Maintenance of Overhead Conductors and Devices	$ 58,353	$ 79,075	$ 90,730	$ 82,836	$ 32,377	55.48%	$ 11,655	14.74%	-$ 7,894	-8.70%
5130	Maintenance of Overhead Services	$ 33,216	$ 57,337	$ 75,842	$ 67,233	$ 42,626	128.33%	$ 18,505	32.27%	-$ 8,609	-11.35%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 39,542	$ 51,225	$ 77,873	$ 77,653	$ 38,331	96.94%	$ 26,648	52.02%	-$ 220	-0.28%
5145	Maintenance of Underground Conduit	-$ 623	-$ 76	$ -	$ -	$ 623	-100.00%	$ 76	-100.00%	$ -	
5150	Maintenance of Underground Conductors and Devices	$ 402	$ 24,137	$ -	$ -	-$ 402	-100.00%	-$ 24,137	-100.00%	$ -	
5155	Maintenance of Underground Services	$ 9,725	$ 8,750	$ 15,029	$ 13,817	$ 5,304	54.54%	$ 6,279	71.76%	-$ 1,212	-8.06%
5160	Maintenance of Line Transformers	$ 23,619	$ 63,243	$ 85,784	$ 78,586	$ 62,165	263.21%	$ 22,541	35.64%	-$ 7,198	-8.39%
5175	Maintenance of Meters	$ 425	$ 9,550	$ 48,178	$ 48,178	$ 47,753	11235.73%	$ 38,628	404.50%	$ -	0.00%
Total - Maintenance		$ 225,316	$ 397,852	$ 489,114	$ 460,674	$ 263,798	117.08%	$ 91,262	22.94%	-$ 28,440	-5.81%
Account	**Description**										
Billing and Collecting											
5305	Supervision	$ 8,214	$ 9,824	$ 4,284	$ 4,284	-$ 3,930	-47.85%	-$ 5,540	-56.39%	$ -	0.00%
5310	Meter Reading Expense	$ 111,485	$ 172,730	$ 168,662	$ 166,644	$ 57,177	51.29%	-$ 4,068	-2.36%	-$ 2,018	-1.20%
5315	Customer Billing	$ 253,712	$ 264,282	$ 360,711	$ 360,711	$ 106,999	42.17%	$ 96,429	36.49%	$ -	0.00%
5320	Collecting	$ 62,378	$ 55,130	$ 43,983	$ 43,983	-$ 18,395	-29.49%	-$ 11,147	-20.22%	$ -	0.00%
5325	Collecting - Cash Over and Short	$ 0	$ 70	$ -	$ -	-$ 0	-100.00%	-$ 70	-100.00%	$ -	
5330	Collection charges	$ -	$ 573	$ 6,630	$ 6,630	$ 6,630		$ 6,057	1057.57%	$ -	0.00%
5335	Bad Debt Expense	-$ 28,147	$ 4,180	$ 6,000	$ 6,000	$ 34,147	-121.32%	$ 1,820	43.55%	$ -	0.00%
Total - Billing and Collecting		$ 407,642	$ 506,789	$ 590,270	$ 588,252	$ 182,628	44.80%	$ 83,481	16.47%	-$ 2,018	-0.34%
Account	**Description**										
Community Relations											
5410	Community Relations - Sundry	$ 10,846	$ 11,649	$ 9,000	$ 9,000	-$ 1,846	-17.02%	-$ 2,649	-22.74%	$ -	0.00%
5415	Energy Conservation	$ 41,058	$ -	$ -	$ -	-$ 41,058	-100.00%	$ -		$ -	
5515	Advertising Expenses	$ 1,384	$ 100	$ 3,500	$ 3,500	$ 2,116	152.84%	$ 3,400	3400.00%	$ -	0.00%
Total - Community Relations		$ 53,288	$ 11,749	$ 12,500	$ 12,500	-$ 40,788	-76.54%	$ 751	6.39%	$ -	0.00%
Account	**Description**										
Administrative and General Expenses											
5615	General Administrative Salaries and Expenses	$ 367,268	$ 465,175	$ 614,579	$ 614,579	$ 247,311	67.34%	$ 149,404	32.12%	$ -	0.00%
5620	Office Supplies and Expenses	$ 43,289	$ 42,000	$ 44,861	$ 44,694	$ 1,572	3.63%	$ 2,861	6.81%	-$ 167	-0.37%
5630	Outside Services Employed	$ 86,805	$ 43,503	$ 86,856	$ 86,856	$ 51	0.06%	$ 43,353	99.65%	$ -	0.00%
5635	Property Insurance	$ 4,139	$ 8,642	$ 23,307	$ 23,307	$ 19,168	463.16%	$ 14,665	169.69%	$ -	0.00%
5640	Injuries and Damages	$ 16,732	$ 13,144	$ -	$ -	-$ 16,732	-100.00%	-$ 13,144	-100.00%	$ -	
5645	Employee Pensions and Benefits	$ -	$ -	$ 5,998	$ 5,998	$ 5,998		$ 5,998		$ -	0.00%
5655	Regulatory Expenses	$ 33,993	$ 26,173	$ 59,520	$ 59,520	$ 25,527	75.10%	$ 33,347	127.41%	$ -	0.00%
5665	Miscellaneous General Expenses	$ -	$ 21,455	$ 99,401	$ 99,401	$ 99,401		$ 77,946	363.30%	$ -	0.00%
5675	Maintenance of General Plant	$ 42,818	$ 60,004	$ 113,093	$ 113,093	$ 70,276	164.13%	$ 53,089	88.48%	$ -	0.00%
5680	Electrical Safety Authority Fees	$ 4,351	$ 4,777	$ 5,100	$ 5,100	$ 749	17.21%	$ 323	6.76%	$ -	0.00%
Total - Administrative and General Expenses		$ 599,394	$ 684,872	$ 1,052,715	$ 1,052,548	$ 453,321	75.63%	$ 367,843	53.71%	-$ 167	-0.02%
Account	**Description**										
Taxe Other Than Income Taxes											
6105	Taxes Other Than Income Taxes	$ 28,221	$ 25,130	$ 27,540	$ 27,540	-$ 681	-2.41%	$ 2,410	9.59%	$ -	0.00%
Total - Other Than Income Taxes		$ 28,221	$ 25,130	$ 27,540	$ 27,540	-$ 681	-2.41%	$ 2,410	9.59%	$ -	0.00%
Account	**Description**										
Other Deductions											
6205	Donations - LEAP program			$ 4,117	$ 4,117	$ 4,117		$ 4,117		$ -	0.00%
Total - Other deductions				$ 4,117	$ 4,117	$ 4,117		$ 4,117		$ -	0.00%
Total OM&A		$ 1,501,298	$ 1,805,717	$ 2,459,977	$ 2,623,797	$ 958,679	63.86%	$ 654,260	36.23%	$ 163,820	6.66%

2006 ACTUAL VERSUS 2012 TEST YEAR

<u>5085 – Miscellaneous Distribution Expense (CGAAP) - $86,826</u>

Prior to 2011 expenses for the Engineering and Operations Departments related to health & safety, training and education, communications, meals, travel, incidentals, and the GIS system were spread over numerous accounts. In 2011 GPI's account structure was re-aligned with the Uniform System of Accounts and the difference between 2006 Actual and 2012 Test reflects this change. A significant portion of the total cost difference relates to wages - $53,144 (burdened cost in 2012).

Budgeted items in 2012 which did not exist in 2006 are as follows:

- Distribution System analysis using DESS Software - $5,000
- Harris MeterSense Operational Data Store support and per meter fees - $16,378
- Engineering Co-op Student - $12,240
- Various third party costs for training, education, seminars, conferences $12,771

5160 – Maintenance of Line Transformers $62,165

In 2012 an additional activity has been added to this account which is the painting of Pad-Mounted transformers. The subcontractor costs for this work are estimated to cost $12,240. This work has been identified during plant inspections and is required to limit the degradation of transformer cases as a result of deteriorated paint. Grimsby Power also charges time to this account when transferring transformers from old to new poles as this relates to capital project work. In 2012 labour & truck represents $53,230 - an increase in activity as compared with 2006.

5310 – Meter Reading Expense $57,177

GPI currently has a number of disparate systems and service providers which enable GPI to process meter data. The net increase in costs is approximately $46,000 and includes a third party service to provide a consolidated end to end solution to obtain and verify meter readings.

5315 – Customer Billing $106,999

In 2008 Grimsby Power was advised by Advanced Utility Systems, the customer information system software vendor, that GPI's version of the software would not be supported after January 1, 2009. During this time frame Grimsby Power was in discussions with FortisOntario to provide a hosted CIS platform using Canadian

Niagara Power Inc.'s SAP CIS billing solution. As part of this service offering Grimsby Power Inc. would pay a monthly service charge to utilize Canadian Niagara Power Inc.'s SAP CIS billing solution. The SAP CIS billing solution went live in May of 2009 and service charges began at this time. The difference in costs between the Advanced System and the service provided by Canadian Niagara Power Inc.'s is a net increase of $25,989. In addition to this costs for Canada Post have increased by $33,390 since 2006.

5615 – Administrative and General Expenses $247,311

Grimsby Power Inc.'s 2012 budget includes the following burdened costs which were in addition to costs incurred in 2006:

- The position of Accounting Assistant was added in 2011
- A portion of the costs for the Finance and Regulatory Analyst
- Prior to 2011 the Director of Engineering's wages were distributed amongst Operations, Maintenance, and Capital accounts. In 2011 these wages were allocated directly to Management Salaries and Expenses (5610).
- Cost for Above - $207,514

In 2012 a specific focus has been made on training, education, and industry seminars and conferences. In 2006 thru 2009 there was less of a focus on these items as these items were reduced in order to keep costs as low as possible. In 2006 there were no expenditures for direct costs in this area. Training and contact with industry counterparts is a key to the future success of employees at Grimsby Power Inc. Direct costs associated with these items attributes to $19,831 in 2012.

5665 – Miscellaneous General Expenses $99,401

In 2011 GPI's account structure was re-aligned with the Uniform System of Accounts. In 2006 this account was not utilized for reporting purposes ($0 balance). Starting in 2011 this account was used to account for Memberships and Directors Fees & Expenses. Previously these costs were allocated to account 5615.

5675 – Maintenance of General Plant $70,276

In 2011, GPI's account structure was re-aligned with the Uniform System of Accounts. The cost centres noted below were previously allocated to different accounts as noted:

- Network Support (Web Hosting, Security, etc.) - Allocated
- Internet Service - 5620
- Engineering Software Service - Allocated

Network related expenses included in the 2012 budget amount to $32,591.

In 2012 new costs (as compared with 2006) have been added to this account for annual upkeep as follows:

- Annual maintenance of GPI's corporate website $10,000
- Security audit of GPI's computer network $10,000
- Increase in internet capacity $8,568
- Regular lawn & ground maintenance incl. snow removal $10,445

2010 ACTUAL VERSUS 2012 TEST YEAR
5085 - Miscellaneous Distribution Expense $92,398

Expenses for 2010 were actually less in this GL as compared to 2006. The explanation provided under variance analysis for 2006 Actual to 2012 Test Year applies here as well.

5315 – Customer Billing $96,429

Expenses for 2010 were slightly higher but consistent with 2006 expenses. The explanation provided under variance analysis for 2006 Actual to 2012 Test Year applies here as well.

5615 – Administrative and General Expenses $149,404

Prior to 2011 the Director of Engineering's wages were distributed amongst Operations, Maintenance, and Capital accounts. In 2011 these wages were allocated directly to Management Salaries and Expenses (5610).

5665 - Miscellaneous General Expenses $77,946

In 2011 GPI's account structure was re-aligned with the Uniform System of Accounts. In 2009 & 2010 this account was utilized to record GPI's Electrical Distributors Association (EDA) and Utility Standards Forum (USF) membership fees only. Starting in 2011 this account was used to account for other Memberships and Directors Fees & Expenses. Previously these costs were allocated to account 5615.

5675 – Maintenance of General Plant $53,089

In 2011 GPI's account structure was re-aligned with the Uniform System of Accounts. The cost centres noted below were previously allocated to different accounts as noted:

- Network Support (Web Hosting, Security, etc.) - Allocated
- Internet Service - 5620
- Engineering Software Service - Allocated

Network related expenses included in the 2012 test year amount to $32,591.

In 2012 new costs (as compared with 2010) have been added to this account for annual upkeep as follows:

- Annual maintenance of GPI's corporate website $10,000
- Security audit of GPI's computer network $10,000
- Increase in internet capacity $8,568

2012 TEST YEAR (MIFRS) VERSUS 2012 TEST YEAR (CGAAP)
<u>5085 – Miscellaneous Distribution Expense (IFRS) $169,494</u>

Under IFRS certain allocations with respect to truck repairs and maintenance, stores expenses, and engineering expenses must be directly expensed to OM&A instead of allocating across both OM&A and Capital. Grimsby Power Inc. has identified and purposely placed expenses in this miscellaneous account for presentation purposes. In the future under IFRS a number of new accounts will be needed to account for direct as opposed to allocated expenses. The specific costs redirected are as follows:

- Truck Maintenance & Repair - $53,333
- Stores - $13,856
- Engineering - $102,305

ONE TIME COSTS

Grimsby Power Inc. has identified only one (1) one-time cost in the 2012 test year. This cost is attributed to third party expenses estimated to occur as a result of the 2011 Cost of Service application process. The cost has been estimated at $100,000. In terms of the 2012 test year $25,000 has been included in the cost figures. This effectively annualizes the cost by spreading the cost over the four year rebasing timeframe.

LOW INCOME ENERGY CONSUMER PROGRAMS (LEAP)

Grimsby Power Inc. has included the cost of the Low Income Assistance Program (LEAP) in account 6205 – Other Deductions – Donations. This amount is calculated as 0.12% of the 2011 Test year Revenue of $3,430,927 as a proxy for 2012. LEAP Funding is equal to $4,117.

SPECIAL PURPOSE CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT 2009

Grimsby Power Inc has included $27,204 for consultant's fees and training in 2012 to assist with the development of strategies or studies with respect to the GEGEA.

CHARITABLE DONATIONS

Grimsby Power has not included any charitable donations in OM&A expenses for 2012.

REGULATORY COSTS

Detailed regulatory costs are presented in Table 4.14. Regulatory costs for the 2012 Test Year amount to $59,520. Regular ongoing costs included with Grimsby Power Inc.'s 2012 budget include OEB assessments and third party professional services/consulting costs anticipated for the 2012 IRM application. Cost of service application costs have been included at $100,000 distributed over a four year period ($25,000 in 2012).

Table 4.14 Regulatory Costs (Board Appendix 2-H)

	Regulatory Cost Category	USoA Account	One-time Cost? [2]	Last Rebasing Year (2006)	Last Year of Actuals (2010)	Bridge Year (2011)	Annual % Change	Test Year (2012)	Annual % Change
	(A)	(B)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655	On-Going	$ 22,675	$ 23,382	$ 24,000	2.64%	$ 25,720	7.17%
2	OEB Hearing Assessments (applicant-originated)								
3	OEB Section 30 Costs (OEB-initiated)	5655	On-Going	$ 240	$ 790	$ 800	1.32%	$ 1,000	25.00%
4	Expert Witness costs for regulatory matters								
5	Legal costs for regulatory matters		On-Going						
6	Consultants' costs for regulatory matters	5655	On-Going			$ 400		$ 5,000	1150.00%
6	Consultants' costs for regulatory matters	5630	On-Going	$ 450	$ 1,424				
7	Operating expenses associated with staff resources allocated to regulatory matters								
8	Operating expenses associated with other resources allocated to regulatory matters [1]								
9	Other regulatory agency fees or assessments	5655	On-Going	$ 800	$ 800	$ 800	0.00%	$ 800	0.00%
10	Any other costs for regulatory matters (please define) publication costs	5655	On-Going		$ 1,201	$ 500	-58.37%	$ 2,000	300.00%
11	Cost of Service Application - legal, consultants and intervenors costs	5655	On-Time	$ 10,277				$ 25,000	
12	Sub-total - Ongoing Costs [3]			$ 24,165	$ 27,597	$ 26,500	-3.97%	$ 34,520	30.26%
13	Sub-total - One-time Costs [4]			$ 10,277	$ -	$ -		$ 25,000	
14	Total			$ 34,443	$ 27,597	$ 26,500	-3.97%	$ 59,520	124.60%

SHARED SERVICES/CORPORATE COST ALLOCATION

Introduction

Grimsby Power Inc. receives or provides services from its related corporate entities. The major services in terms of expense above the materiality threshold of $50,000 are as follows:

- Receives services:
  - Electrical transformation services from Niagara West Transformation Corporation
- Provides services:
  - Electricity distribution services to the Town of Grimsby

A summary of charges to affiliates for services provided in 2006 Actual thru 2010 Actual together with the projections for the 2011 Bridge Year and 2012 Test Year, are shown in Tables 4.15 thru 4.21.

SERVICES PROVIDED BY GRIMSBY POWER INC. (GPI) TO TOWN OF GRIMSBY

Street Light Services

Grimsby Power Inc. provides administrative, installation, and maintenance services for street lights to the Town of Grimsby. These services are provided based on employee time at fully burdened rates, as well as truck and material expenses at fully burdened rates/costs.

Electricity

The Town of Grimsby is an electricity customer of Grimsby Power Inc.

SERVICES PROVIDED BY GRIMSBY POWER INC. TO GRIMSBY HYDRO INC. (GHI)

Book Keeping Services

Grimsby Power Inc.'s Director of Finance provides book keeping services to Grimsby Hydro Inc.

SERVICES PROVIDED BY GRIMSBY POWER INC. TO NIAGARA POWER INC. (NPI)

Book Keeping Services

Grimsby Power Inc.'s Director of Finance provides book keeping services to Niagara Power Inc.

SERVICES PROVIDED BY GRIMSBY POWER INC. TO NIAGARA REGIONAL BROADBAND NETWORKS (NRBN)

Fibre Optic Cable Pole Rental

Grimsby Power Inc. charges Niagara Regional Broadband Networks a pole rental fee for Niagara Regional Broadband Networks attachments to Grimsby Power Inc.'s distribution poles.

SERVICES PROVIDED BY TOWN OF GRIMSBY TO GRIMSBY POWER INC.

Water Billing Services

Grimsby Power Inc. is a water customer of the Town of Grimsby.

Property Taxes

Grimsby Power Inc. is land owner in the Town of Grimsby and therefore attracts municipal property taxes.

Fuel

Grimsby Power Inc. purchases its fuel (diesel and gasoline) for its trucks, light vehicles, and equipment from the Town of Grimsby.

SERVICES PROVIDED BY NIAGARA POWER INC. TO GRIMSBY POWER INC.

In the years 2006 to 2010 Niagara Power Inc (NPI) provided governance and management services to Grimsby Power Inc.

SERVICES PROVIDED BY NIAGARA REGIONAL BROADBAND NETWORKS TO GRIMSBY POWER INC.

Niagara Regional Broadband Networks provides Grimsby Power Inc. with fibre optic network connectivity services.

SERVICES PROVIDED BY NIAGARA WEST TRANSFORMER CORPORATION (NWTC) TO GRIMSBY POWER INC.

Niagara West Transformer Corporation operates a transformer station upon which Grimsby Power Inc. is connected to the transmission system. Niagara West Transformation Corporation charges a transformation service fee based on $/kW utilization to Grimsby Power Inc.

SERVICES PROVIDED BY CANADIAN NIAGARA POWER A FORTISONTARIO COMPANY TO GRIMSBY POWER INC.

Canadian Niagara Power a FortisOntario company maintains a customer information system (CIS) for Grimsby Power Inc. under a software as a solution (SAAS) model.

SERVICES PROVIDED BY FORTISONTARIO TO GRIMSBY POWER INC.

FortisOntario provides Grimsby Power Inc. with smart meter implementation and consultation services as it relates to the integration of the smart meter systems with the customer information system (CIS).

CORPORATE COST ALLOCATION (BOARD APPENDIX 2-L)

Table 4.15 2006 Shared Services/Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	Service	Service	Allocation
From	To					
				$	$	%
GPI	Town of Grimsby	Power Electricity	Market Rate	$ 451,036		
GPI	Town of Grimsby	Streetlights Services	Fixed Fee/Cost-Based	$ 34,915		
GPI	NRBN	Pole Rental	Market Rate	$ 14,997		
GPI	NPI	Bookkeeping Services	Fixed Fee	$ 2,265		
Town of Grimsby	GPI	Water Billing Services	Market Rate	$ 444		
Town of Grimsby	GPI	Fuel Billing Services	Cost-Plus	$ 14,667		
Town of Grimsby	GPI	Property taxes	Market Rate	$ 23,795		
NRBN	GPI	Internet Service	Market Rate	$ 9,007		
NWTC	GPI	Connection Fees	Market Rate	$ 395,970		
NPI	GPI	Management Fee	Cost-Based	$ 161,469		
NPI	GPI	Board Fees	Cost-Based	$ 53,358		

Table 4.16 2007 Shared Services/Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
GPI	Town of Grimsby	Power Electricity	Market Rate	$ 364,883		
GPI	Town of Grimsby	Streetlights Services	Fixed Fee/Cost-Based	$ 22,407		
GPI	NRBN	Pole Rental	Market Rate	$ 14,997		
GPI	NPI	Bookkeeping Services	Fixed Fee	$ 2,580		
GPI	GHI	Bookkeeping Services	Fixed Fee	$ 825		
Town of Grimsby	GPI	Water Billing Services	Market Rate	$ 413		
Town of Grimsby	GPI	Fuel Billing Services	Market Rate	$ 15,477		
Town of Grimsby	GPI	Property taxes	Market Rate	$ 24,332		
NRBN	GPI	Internet Service	Market Rate	$ 9,007		
NWTC	GPI	Connection Fees	Market Rate	$ 424,335		
NPI	GPI	Management Fee	Cost-Based	$ 162,579		
NPI	GPI	Board Fee	Cost-Based	$ 87,895		

Table 4.17 2008 Shared Services/Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
GPI	Town of Grimsby	Power Electricity	Market Rate	$ 354,817		
GPI	Town of Grimsby	Streetlights Services	Fixed Fee/Cost-Based	$ 28,867		
GPI	NRBN	Pole Rental	Market Rate	$ 14,997		
GPI	NPI	Bookkeeping Services	Fixed Fee	$ 2,670		
GPI	GHI	Bookkeeping Services	Fixed Fee	$ 600		
Town of Grimsby	GPI	Water Billing Services	Market Rate	$ 361		
Town of Grimsby	GPI	Fuel Billing Services	Market Rate	$ 21,466		
Town of Grimsby	GPI	Property taxes	Market Rate	$ 24,484		
NRBN	GPI	Internet Service	Market Rate	$ 9,007		
NWTC	GPI	Connection Fees	Market Rate	$ 377,552		
NPI	GPI	Board Fee	Cost-Based	$ 87,977		
NPI	GPI	Management Fee	Fixed Fee	$ 121,000		
NPI	GPI	Management Fee	Cost-Based	$ 14,467		

Table 4.18 2009 Shared Services/Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
GPI	Town of Grimsby	Power Electricity	Market Rate	$ 312,481		
GPI	Town of Grimsby	Streetlights Services	Fixed Fee/Cost-Based	$ 36,509		
GPI	NRBN	Pole Rental	Market Rate	$ 14,997		
GPI	NPI	Bookkeeping Services	Fixed Fee	$ 2,760		
GPI	GHI	Bookkeeping Services	Fixed Fee	$ 600		
Town of Grimsby	GPI	Water Billing Services	Market Rate	$ 416		
Town of Grimsby	GPI	Fuel Billing Services	Market Rate	$ 13,158		
Town of Grimsby	GPI	Property taxes	Market Rate	$ 25,155		
NRBN	GPI	Internet Service	Market Rate	$ 9,007		
NWTC	GPI	Connection Fees	Market Rate	$ 369,666		
NPI	GPI	Management Fee	Cost-Based	$ 132,000		
NPI	GPI	Board Fee	Cost-Based	$ 54,525		
Fortis/CNP	GPI	IT Maintenance Fee	Cost-Based	$ 22,680		
Fortis/CNP	GPI	Prepayment for ERP Implementation	Cost-Based	$ 94,500		

Table 4.19 2010 Shared Services/Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
GPI	Town of Grimsby	Power Electricity	Market Rate	$ 385,469		
GPI	Town of Grimsby	Streetlights Services	Fixed Fee/Cost-Based	$ 26,265		
GPI	NRBN	Power Electricity	Market Rate	$ 4,233		
GPI	NRBN	Pole Rental	Market Rate	$ 14,997		
GPI	NPI	Bookkeeping Services	Fixed Fee	$ 3,000		
GPI	GHI	Bookkeeping Services	Fixed Fee	$ 600		
Town of Grimsby	GPI	Water Billing Services	Market Rate	$ 449		
Town of Grimsby	GPI	Fuel Billing Services	Market Rate	$ 13,918		
Town of Grimsby	GPI	Property taxes	Market Rate	$ 25,493		
NRBN	GPI	Internet Service	Market Rate	$ 8,549		
NWTC	GPI	Connection Fees	Market Rate	$ 380,511		
NPI	GPI	Management Fee	Cost-Based	$ 11,000		
Fortis/CNP	GPI	IT Maintenance Fee	Cost-Based	$ 43,680		
Fortis	GPI	SM Consulting Fees	Cost-Based	$ 3,467		

Table 4.20 2011 Shared Services/Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
GPI	Town of Grimsby	Power Electricity	Market Rate	$ 390,000		
GPI	Town of Grimsby	Streetlights Services	Fixed Fee/Cost Based	$ 27,052		
GPI	NRBN	Power Electricity	Market Rate	$ 4,600		
GPI	NRBN	Pole Rental	Market Rate	$ 14,997		
GPI	NPI	Bookkeeping Services	Fixed Fee	$ 3,000		
GPI	GHI	Bookkeeping Services	Fixed Fee	$ 600		
Town of Grimsby	GPI	Water Billing Services	Market Rate	$ 450		
Town of Grimsby	GPI	Fuel Billing Services	Market Rate	$ 18,000		
Town of Grimsby	GPI	Property taxes	Market Rate	$ 27,000		
NRBN	GPI	Internet Service	Market Rate	$ 8,400		
NWTC	GPI	Connection Fees	Market Rate	$ 390,000		
Fortis/CNP	GPI	IT Maintenance Fee	Cost-Based	$ 45,000		

Table 4.21 2012 Shared Services/Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
GPI	Town of Grimsby	Power Electricity	Market Rate	$ 390,000		
GPI	Town of Grimsby	Streetlights Services	Fixed Fee/Cost Based	$ 27,864		
GPI	NRBN	Power Electricity	Market Rate	$ 4,600		
GPI	NRBN	Pole Rental	Market Rate	$ 14,997		
GPI	NPI	Bookkeeping Services	Fixed Fee	$ 3,000		
GPI	GHI	Bookkeeping Services	Fixed Fee	$ 600		
Town of Grimsby	GPI	Water Billing Services	Market Rate	$ 450		
Town of Grimsby	GPI	Fuel Billing Services	Market Rate	$ 18,360		
Town of Grimsby	GPI	Property taxes	Market Rate	$ 27,540		
NRBN	GPI	Internet Service	Market Rate	$ 8,568		
NWTC	GPI	Connection Fees	Market Rate	$ 390,000		
Fortis/CNP	GPI	IT Maintenance Fee	Cost-Based	$ 45,900		

METHODOLOGY USED IN DETERMINING PRICES CHARGE TO/FROM AFFLIATES

NPI to GPI Board Fees – Cost Based

The governance of GPI was provided by the NPI Board. The Board Fee was based on the actual board of director hours times a per hour rate times a percentage of the meeting time being allocated to GPI business.

NPI to GPI – Cost-Plus

The management of GPI was provided by the President of NPI. This fee was based on this employee's salary plus payroll burdens plus a mark-up.

NPI to GPI – Management Fees – Fixed Fee

The President of NPI left the corporation at the beginning of 2008. In order to maintain management oversight of GPI a fixed fee was established for the NPI Board to provide this service. The fixed fee was based on the previous cost plus basis noted under "NPI to GPI – Management Fees – Cost-Plus" above without payroll burdens and mark-up.

GPI to the Town of Grimsby for Street Light Services

A two tiered pricing structure has been determined for Street Light Services. Most of the cost is determined through fixed costs. Fixed costs have been established for certain standard types of services such as replace lamp or change a photo cell. These costs are based on the average time to perform the service times the fully burdened expenses for two linemen and a bucket truck. The fixed fees are multiplied by the number of units in each category to determine the total cost.

Some costs such as troubleshooting are not well served by a fixed fee. A time based methodology is utilized for all non-fixed fee work based on:

- Lines Staff Labour – actual hourly rate times # of hours plus percentage burden
- Truck rate – hourly unit rate times # of hours
- Material – inventory cost (average weighted cost) plus percentage burden

VARIANCE ANALYSIS SHARED SERVICES/CORPORATE COST ALLOCATION

Referring to Table 4.22 there are three variances, all in the comparison of the 2012 Test Year with 2006 Actual, that exceed the materiality threshold of $50,000. Details are described below:

- GPI to Town of Grimsby – Power Electricity – -$61,036

  The sale of electricity has declined presumable due to a change in use by the Town and CDM activities.

- NPI to GPI – Management Fee - -$161,469

  A change in corporate governance structure no longer attracts a management fee from NPI.

- NPI to GPI – Board Fees - -$53,358

  A change in corporate governance structure no longer attracts a Board fee from NPI.

Table 4.22 Variance Analysis – Shared Services

						Variance 2012 Test Year to 2006 Actual		Variance 2012 Test Year to 2010 Actual	
Name of Company		Service Offered	Price for Service (2006)	Price for Service (2010)	Price for Service (2012)	Variance $	Variance %	Variance $	Variance %
From	To								
GPI	Town of Grimsby	Power Electricity	$ 451,036	$ 385,469	$ 390,000	-$ 61,036	-13.5%	$ 4,531	1.2%
GPI	Town of Grimsby	Streetlights Services	$ 34,915	$ 26,265	$ 27,864	-$ 7,050	-20.2%	$ 1,600	6.1%
GPI	NRBN	Power Electricity	$ -	$ 4,233	$ 4,600	$ 4,600	100.0%	$ 367	8.7%
GPI	NRBN	Pole Rental	$ 14,997	$ 14,997	$ 14,997	$ -	0.0%	$ -	0.0%
GPI	NPI	Bookkeeping Services	$ 2,265	$ 3,000	$ 3,000	$ 735	32.5%	$ -	0.0%
GPI	GHI	Bookkeeping Services	$ -	$ 600	$ 600	$ 600	100.0%	$ -	0.0%
Town of Grimsby	GPI	Water Billing Services	$ 444	$ 449	$ 450	$ 6	1.4%	$ 1	0.2%
Town of Grimsby	GPI	Fuel Billing Services	$ 14,667	$ 13,918	$ 18,360	$ 3,693	25.2%	$ 4,442	31.9%
Town of Grimsby	GPI	Property taxes	$ 23,795	$ 25,493	$ 27,540	$ 3,745	15.7%	$ 2,047	8.0%
NRBN	GPI	Internet Service	$ 9,007	$ 8,549	$ 8,568	-$ 439	-4.9%	$ 20	0.2%
NWTC	GPI	Connection Fees	$ 395,970	$ 380,511	$ 390,000	-$ 5,970	-1.5%	$ 9,489	2.5%
Fortis/CNP	GPI	IT Maintenance Fee	$ -	$ 43,680	$ 45,900	$ 45,900	100.0%	$ 2,220	5.1%
NPI	GPI	Management Fee	$ 161,469	$ 11,000	$ -	-$ 161,469	-100.0%	-$ 11,000	-100.0%
NPI	GPI	Board Fees	$ 53,358	$ -	$ -	-$ 53,358	-100.0%	$ -	0.0%
Fortis	GPI	SM Consulting Fees	$ -	$ 3,467	$ -	$ -	0.0%	-$ 3,467	-100.0%

Purchase of Products and Services from Non-Affiliates

Grimsby Power Inc. purchases many services and products from third parties. Table 4.23 discloses the expenditures by vendor or service provider where the annual amount exceeded $50,000 per year, for the years 2006, 2007, 2008, 2009 and 2010, respectively.

Commitments to suppliers are ongoing in 2011. Purchases for 2012 have not yet been established but will proceed to be based on the methodology contained within Grimsby Power Inc's Purchasing Policy – Document Number 2.01, which has been attached as Appendix 4.2.

Table 4.23 Purchases from Non-Affiliated Vendors/Service Providers

Name of Vendor	2006	2007	2008	2009	2010	Product/Service	Procurement Method
ADVANCED UTILITY SYSTEMS	$ 54,356					BILLING SOFTWARE	SOLE SOURCE
COLLECTIVE UTILITY SERVICES	$ 64,702	$ 66,023	$ 74,314	$ 61,160	$ 72,901	METER READING	MARKET RATE
CANADA POST		$ 52,970	$ 60,131	$ 64,596	$ 68,334	POSTAGE	MARKET RATE
CANADIAN CABLE INJECTION	$ 76,143					UNDERGROUND DISTRIBUTION WORK	SOLE SOURCE
CANADIAN NIAGARA POWER				$122,490		SAP ERP AND IT SERVICES	PARTNERSHIP
COS COMPUTER SOLUTIONS		$ 90,000				ACCOUNTING SOFTWARE	RFP
DAVEY TREE EXPERT CO.		$ 51,194	$ 53,197	$ 59,845		FORESTRY	TENDER
D L HANNON INC		$407,935		$ 67,590		LINE WORK	TENDER
DUNDAS POWER LINE LTD			$128,522			LINE WORK	TENDER
GRAFTON UTILITY SUPPLY	$497,330	$388,067	$359,340	$379,921	$531,737	MATERIALS	MARKET RATE/ALLIANCE
GROUND AERIAL MAINTENANCE SERVICES					$226,538	LINE WORK	TENDER
GUELPH UTILITY POLE CO. LTD		$ 91,990		$ 71,744	$120,790	MATERIALS	SOLE SOURCE
GUELPH HYDRO ELECTRIC SYSTEMS INC.				$ 51,160		GIS SERVICE PROVIDER	RFP
JESSTEC INDUSTRIES INC				$ 71,403		MATERIALS	RFQ
KPMG	$ 50,245					PROFESSIONAL SERVICES	TENDER
KTI LIMITED				$266,639	$689,471	SMART METERS & TOWERS	TENDER
M3 & W INC.				$ 84,714		CONSERVATION PROJECTS	RFP
OLAMETER INC.					$ 83,237	MASS DEPLOYMENT OF SMART METERS	RFP
SAP CANADA INC			$ 86,931		$ 67,602	SOFTWARE LICENCES	SOLE SOURCE
SOUTHWEST POWER CORP.			$ 76,595		$ 58,947	LINE WORK	TENDER
TRANSELEC COMMON INC.			$ 69,211	$ 83,086	$ 91,289	UNDERGROUND DISTRIBUTION WORK	SOLE SOURCE
WILDERNESS VEGETATION MANAGEMENT					$ 52,749	FORESTRY	TENDER

EMPLOYEE COMPENSATION BREAKDOWN
Compensation/Performance System

Union

Grimsby Power Inc.'s unionized staff is represented by the Power Workers Union. The current collective agreement expires May 31, 2012. It is anticipated Grimsby Power Inc. will be entering formal negotiations in the early part of 2012. The current agreement, which was entered into on June 1, 2009, includes annual wage increases as follows:

- 2.5% per year effective June 1, 2009
- 2.5% per year effective June 1, 2010
- 3.0% per year effective June 1, 2011

More detail on percentage wage increases is contained in Table 4.25 below.

Executive, Management, and Non Union

Executive, Management, and Non Union compensation plans consists of salaries and benefits. Each position within the company has been placed at a base wage grade or on a pay scale which is reviewed annually by the CEO and the Board of Directors' Compensation Committee. Each employee's position is reviewed and adjustments are made based on an inflationary adjustment and performance assessment. Changes to senior management compensation, if any, are approved by the GPI Board. Grimsby Power Inc. has utilized incentive or bonus compensation initiatives on an irregular basis. Grimsby Power Inc. plans to create a formal incentive or bonus plan in 2011.

More detail on percentage wage increases is contained in Table 4.25 below.

Benefits

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, vacation and a defined benefit pension plan (OMERS). The plans are designed to address the health and welfare needs of staff with similar plans for both union and management/non-union employees. All full time staff participates in the OMERS pension plan.

The benefit package applies to all full time staff and ends when employees are terminated. Retirement benefits are not available as part of the benefit package.

Employee Compensation and Benefits

Grimsby Power Inc. has set out the information in Table 4.24 below according to Section 6-4 of the 2007 EDR Handbook where it states "For an applicant with fewer than three employees, reporting of employee compensation under this section is not required. In cases where there are three or fewer, full time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer FTEs." Grimsby Power Inc. has aggregated the executive, management, and non-union staff together in the Management category of Table 4.24.

Employee complement, compensation and benefits are set out in Table 4.24 below. An allocation has been completed at the bottom of the table to show how many dollars of the total compensation and benefits is charged to OM&A versus being capitalized. All salary increases for both Management and Union staff are noted in Table 4.24 below.

Table 4.24 Employee Compensation and Benefits (Board Appendix 2-K)

	2006 - Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 CGAAP Test Year
Number of Employees (FTEs including Part-Time)[1]								
Executive		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management		$ 7	$ 7	$ 7	$ 7	$ 8	$ 8	$ 8
Non-Union		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union		$ 8	$ 8	$ 9	$ 9	$ 9	$ 10	$ 11
Total	$ -	$ 15	$ 15	$ 16	$ 16	$ 17	$ 18	$ 19
Number of Part-Time Employees								
Executive		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management		$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
Non-Union		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
Total Salary and Wages								
Executive								
Management		$ 321,734	$ 391,759	$ 408,088	$ 423,621	$ 530,311	$ 551,754	$ 543,313
Non-Union								
Union		$ 434,156	$ 447,538	$ 524,576	$ 510,853	$ 533,906	$ 594,264	$ 691,844
Total	$ -	$ 755,890	$ 839,297	$ 932,664	$ 934,474	$ 1,064,217	$ 1,146,018	$ 1,235,157
Current Benefits								
Executive								
Management		$ 93,002	$ 138,473	$ 123,583	$ 137,785	$ 169,822	$ 171,863	$ 182,379
Non-Union								
Union		$ 133,702	$ 140,957	$ 176,361	$ 157,230	$ 160,860	$ 187,452	$ 216,281
Total	$ -	$ 226,704	$ 279,430	$ 299,944	$ 295,015	$ 330,682	$ 359,315	$ 398,660
Accrued Pension and Post-Retirement Benefits								
Executive								
Management		$ 2,987	$ 3,316	$ 3,429	$ 3,578	$ 4,051	$ 4,161	$ 7,215
Non-Union								
Union								
Total	$ -	$ 2,987	$ 3,316	$ 3,429	$ 3,578	$ 4,051	$ 4,161	$ 7,215
Total Benefits (Current + Accrued)								
Executive	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ 95,989	$ 141,789	$ 127,012	$ 141,363	$ 173,873	$ 176,024	$ 189,594
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ 133,702	$ 140,957	$ 176,361	$ 157,230	$ 160,860	$ 187,452	$ 216,281
Total	$ -	$ 229,691	$ 282,746	$ 303,373	$ 298,592	$ 334,733	$ 363,476	$ 405,875
Total Compensation (Salary, Wages, & Benefits)								
Executive	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ -	$ 417,724	$ 533,548	$ 535,100	$ 564,984	$ 704,184	$ 727,778	$ 732,907
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ 567,857	$ 588,495	$ 700,937	$ 668,082	$ 694,766	$ 781,716	$ 908,124
Total	$ -	$ 985,581	$ 1,122,043	$ 1,236,037	$ 1,233,066	$ 1,398,950	$ 1,509,494	$ 1,641,032
Compensation - Average Yearly Base Wages								
Executive								
Management		$ 49,959	$ 60,271	$ 67,398	$ 66,942	$ 70,708	$ 73,567	$ 72,442
Non-Union								
Union		$ 54,269	$ 55,942	$ 58,286	$ 56,761	$ 59,323	$ 59,426	$ 62,895
Total		$ 104,229	$ 116,213	$ 125,684	$ 123,703	$ 130,031	$ 132,994	$ 135,337
Compensation - Average Yearly Overtime								
Executive								
Management		$ 3,775	$ 5,030	$ 11,823	$ 5,963	$ 3,988	$ 4,108	$ 4,231
Non-Union								
Union		$ 23,239	$ 18,437	$ 29,382	$ 25,930	$ 23,278	$ 23,976	$ 24,696
Total		$ 27,014	$ 23,467	$ 41,205	$ 31,893	$ 27,266	$ 28,084	$ 28,927
Compensation - Average Yearly Incentive Pay								
Executive								
Management		$ 3,000		$ 30,000	$ 11,500		$ 27,810	$ 28,644
Non-Union								
Union								
Total		$ 3,000	$ -	$ 30,000	$ 11,500	$ -	$ 27,810	$ 28,644
Compensation - Average Yearly Benefits								
Executive								
Management		$ 14,308	$ 21,304	$ 19,013	$ 21,198	$ 22,643	$ 22,915	$ 24,317
Non-Union								
Union		$ 16,713	$ 17,620	$ 19,596	$ 17,470	$ 17,873	$ 18,745	$ 19,662
Total		$ 31,021	$ 38,923	$ 38,608	$ 38,668	$ 40,516	$ 41,660	$ 43,979
Total Compensation	$ -	$ 985,581	$ 1,122,043	$ 1,236,037	$ 1,233,066	$ 1,398,950	$ 1,509,494	$ 1,641,032
Total Compensation Charged to OM&A		$ 919,603	$ 1,053,056	$ 1,181,813	$ 1,122,110	$ 1,281,333	$ 1,339,957	$ 1,470,620
Total Compensation Capitalized	$ -	$ 65,978	$ 68,987	$ 54,224	$ 110,956	$ 117,617	$ 169,537	$ 170,412

Table 4.25 Percentage Wage/Salary Increases

	2004		2005		2006		2007		2008		2009		2010		2011		2012	
	Month	%	Month	%	Month	%	Month	%	Month	%	Month	%	Month	%	Month	%	Month	%
Management/Non Union	Jan	3	Jan	3	Jan	3	Jan	2.5	Jan	3	Jan	2.5	Jan	2.5	Jan	3	Jan	3
Union	June	3	June	3	June	3	June	3.25	June	3	June	2.5	June	2.5	June	3	June	3

Change in Employee Compensation & Benefits

2006 Actual vs. 2004 Actual

Management

Change in FTE: No Change

The difference in FTE count is noted as "No Change" however, a significant change was made in 2005. On January 1, 2005 The President of Grimsby Power Inc. was transferred to Niagara Power Inc. thus eliminating the expenditure for Grimsby Power Inc. in terms of salary and benefits. The day to day management of Grimsby Power Inc. was also transferred to Niagara Power Inc. This position (within Grimsby Power Inc.) remained vacant until 2010.

Anticipating the increased demands placed on staff to produce (and report) the information required for a rate rebasing application, to enable the central co-ordination of regulatory reporting, and to facilitate Conservation and Demand Management initiatives a Regulatory Analyst position was created and filled in November of 2006.

The Director of Finance position was left vacant for a period of approximately six weeks in April and May of 2004 thus, reducing wages and benefits in this period.

In 2005, in preparation for a leave, the Director of Finance position was backfilled utilizing a twelve month contract. The contract began at the end of August 2005 and for approximately five weeks there was an overlap. This effectively increased the costs for this position. Also as of June 1, 2005 the number of hours for staff on a 35 hour work week was changed to a 37.5 hour work week. This increased the costs for this year and the subsequent years as the 37.5 hour work week was maintained.

In March of 2006 the contracted Director of Finance left the corporation and another contracted Accounting Assistant was hired in May 2006 for a period of approximately six months. The Director of Finance on leave returned in September 2006. This movement of employees within the finance department resulted in decreased wage and benefit expenses for this period for the Director of Finance position.

Union
Change in FTE: No Change

2007 Actual vs. 2006 Actual
Management
Change in FTE: No Change

In 2007 the full extent of expenses (increasing expenses) for the Regulatory Analyst position is realized in salary and benefits.

Union
Change in FTE: No Change

2008 Actual vs. 2007 Actual
Management
Change in FTE: No Change

In 2008 the Director of Finance position was vacant for approximately four and one half months reducing salary and benefits for this position.

Union
Change in FTE: Plus 1

With respect to the Line Department a succession planning exercise highlighted the following:

- The Line Superintendent position would likely need to be filled in the next five years due to a pending retirement;
- In 2001 the Line Department was comprised of five FTE employees – a Line Superintendent and Four Journeyman Lineman. In late 2001 and early 2002 two of the Journeyman Lineman left Grimsby Power Inc. and they were not replaced;
- In 2008 the two Journeyman Linemen were within 10 years of early retirement.
- Hiring another lineman would reduce the need to hire Line Contractors by an equivalent of one FTE.
- In 2008 a report by the Electricity Sector Council titled "Powering Up The Future – 2008 Labour Market Information Study" reported that for Electrical Power Line and Cable Workers the vacancy rate was 4.9% and it was also predicted that there would be a shortage of qualified applicants (trades/other non-support category) for these positions.

Based on this information it was decided that the best course of action would be to hire a Line Apprentice. Hiring at this time would allow the person in this position to gain valuable experience and become competent given that, on average, it takes approximately ten years to become a competent and experienced Journeyman Lineman. This position was filled in August 2008.

One of the Line Staff was on leave for approximately two months thus, reducing wages during this period.

In order to assist with the build of capital distribution projects two contracted Power Lineman from the Power Workers Union (Union Hall) were placed on payroll for a period of time. This added approximately $43,000 to wages.

2009 Actual vs. 2008 Actual

Management
Change in FTE: No Change

Union
Change in FTE: No Change

One of the Line Staff was on leave for approximately six weeks thus, reducing wages during this period.

2010 Actual vs. 2009 Actual
Management
Change in FTE: Plus 1

During the period from early 2007 until mid 2009 numerous explorations were made with respect to potential mergers, amalgamations, or an outright sale of the utility. As these discussions were ongoing it was decided to delay the hiring of an executive in the role of President/CEO. In 2009 Niagara Power Inc. Board of Directors approved the acquisition of an interest in Grimsby Power Inc. to FortisOntario. With this acquisition and the subsequent stability it brought, the Board of Directors approved the search for a new President/CEO. The search ended in a successful placement in February of 2010.

Union
Change in FTE: No Change

2011 Bridge vs. 2010 Actual
Management
Change in FTE: No Change

Union
Change in FTE: Plus 1

The responsibility for financial record keeping and reporting rested with the Director of Finance who performed all of the day to day accounting functions. This task was found to be very onerous for one person and as a result of having only one person competent to perform this function a vacancy or extended absence posed a serious risk to the completion of day to day accounting activities. Throughout the years from 2006 to late 2008 a period of instability occurred in the Finance Department with upheaval in the Director of Finance position. During this period a number of different people held this position. In October of 2008 a new Director of Finance was hired and stability was attained. However, in order to mitigate the risk, as experienced in the past, and lessen the work load to a reasonable level a new position, the Accounting Assistant, was created with responsibilities to perform the day to day accounting functions. Initially in 2010 this position was filled with a contract employee hired through a placement agency and then subsequently filled in April of 2011 with a permanent employee.

In addition to this permanent employee a coop student is budgeted to be hired into the Engineering Department for a 4 month work term to assist with Graphic Information System (GIS) development. Grimsby Power Inc. manages its GIS with regular employees, however additional resources are required to develop and concentrate on specific aspects of the GIS system. Hiring a coop student is an efficient way to complete this type of work. The student has not been included in the FTE count but is included in the Table 4.24 above in terms of expenses.

2012 Test vs. 2011 Bridge

Management
Change in FTE: No Change

Union
Change in FTE: Plus 1

In early 2011 the position of Regulatory Analyst became vacant. Originally this position was created to be primarily responsible for regulatory activity. However, with the creation of conservation and demand management programs this position transitioned to be primarily responsible for the development and execution of CDM programs. As a result of the vacancy, this position is being re-aligned to reflect an increased responsibility for financial and regulatory functions and a decreased responsibility for CDM. As a result of this re-alignment the pay structure has been changed to reflect the job description – an increase in wage rate.

In 2010, budget approval (for 2011) was granted to hire an additional lineman. The timing of this placement is to take place in mid to late December of 2011. Justification for this position is as documented below. As the FTE count for this position is insignificant in 2011 the full FTE has been recognized in 2012 (see Table 4.24).

In 2010 the Operations Department was staffed with three Journeyman Linemen (two experienced Lineman and one apprentice) who at the time had finished the third year of a four year program. In the past, the Line Superintendent has supplied back-up Journeyman Lineman services when required. On call is shared with one other Engineering staff member which makes a five week on call rotation which includes the Line Superintendent. This schedule in itself is not onerous but most line work requires a minimum of two Linemen which essentially reduces the on-call schedule to every two weeks. This complement of staff has the following negatives:

- On call duty is very frequent – equivalent to every two weeks;
- When one Lineman is on vacation only two lineman are available for regular work limiting what the crew can do;
- A regular crew of three Linemen has limitations which could result in the crew taking health & safety shortcuts – "the work has to get done attitude" which is not an acceptable outcome.

Adding an additional Journeyman Lineman (fully certified lineman (preferred) or apprentice) will result in the following positive changes:

- On call duty will be reduced;
- A regular crew of four Lineman is much more versatile in the work that can be accomplished making the work safer and more efficient;

- Contract line work currently costs the corporation $100,000's of dollars each year. Additional line staff to Grimsby Power Inc. will reduce this spend by the amount of one full time equivalent (FTE) lineman;
- Grimsby Power Inc.'s current and future mobile equipment will not have to be increased to accommodate the extra Lineman. – no additional equipment expenses.

In addition to this permanent employee a coop student is budgeted to be hired into the Engineering Department for a 4 month work term to assist with GIS development. The same description as above in 2011 Bridge vs. 2010 Actual year applies.

OMERS PENSION EXPENSE AND POST RETIREE BENEFITS

OMERS Pension Expense

Grimsby Power Inc's employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). Accordingly, Grimsby Power Inc. has provided the OMERS pension premium information for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and the 2012 Test Year in the Table 4.26 below.

Table 4.26 Pension Premium Information

	2006 Last Rebasing Year Actuals	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
OMERS Premiums Paid	$ 49,397	$ 58,064	$ 59,991	$ 63,503	$ 76,319	$ 103,000	$ 123,000

Post – Retirement Benefits – Liability

Grimsby Power Inc. has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2006

Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and 2012 Test Year, in Table 4.27 below.

Post – Retirement Benefits – Premiums

Grimsby Power Inc. pay's certain post retirement benefits on behalf of its retired employees. Actual premiums paid for 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year, and 2012 Test Year, are shown in Table 4.27 below.

Table 4.27 Post – Retirement Benefit Information

	2006 Last Rebasing Year Actuals	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Post Retirement Premiums & Expenses Paid	$ 2,987	$ 3,316	$ 3,429	$ 3,578	$ 4,051	$ 4,161	$ 7,215
Change in Accrued Liability	$ 325	$ 329	$ 113	$ 149	$ 473	$ 110	$ 3,054
Total Post Employment Benefit Expense	**$ 3,312**	**$ 3,645**	**$ 3,542**	**$ 3,727**	**$ 4,524**	**$ 4,271**	**$ 10,269**

DEPRECIATION, AMORTIZATION AND DEPLETION

Amortization on capital assets is calculated as follows:

- Grimsby Power Inc. uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools. Amortization is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:
- Grimsby Power Inc.'s amortization policy has been to take a full year's amortization on capital additions during the current year. As per OEB

guidelines, LDCs are required to use the half-year rule when accounting for amortization expense. For this rate application, Grimsby Power Inc. has applied the half year rule for calculating depreciation expense for the year 2012. Grimsby Power Inc. recognizes that it should have changed its accounting policy to the half year rule. However due to a change in management staff this did not occur. Grimsby Power Inc. will change its accounting policy for amortization to reflect the half year rule for 2012.

- Depreciation rates are in line with rates set out in the APH. These rates are reflected in Tables 4.28 to 4.31 that follow.
- CGAAP vs. IFRS - On March 15th the OEB released information amending a November 8th, 2010 directive which effectively requires the 2012 test year forecasts to be in MIFRS format. Most LDC's are required to transition to the MIFRS format as of January 1, 2012. The OEB directive states:
  - **"…should make all reasonable efforts to provide forecasts for the 2012 test year (and any other subsequent test years) in modified IFRS accounting format"**
  - **"For those distributors, the Board will, when approving an effective date for 2012 rates, consider any reasonable delay in filing caused by additional work to file on the basis of modified IFRS"**

In terms of depreciation it is necessary to evaluate the useful lives of assets utilizing the standards set out in the IFRS rules. To assist Grimsby Power Inc. in this process KPMG, a leader in IFRS transition, was hired to lead Grimsby Power staff through the process of evaluating potentially new useful lives to be determined for all of its assets. In conjunction with KPMG the Kinectrics study titled "Asset Depreciation Study for the Ontario Energy Board" was heavily utilized to validate if Grimsby Power Inc.'s assessment was in line with industry norms.

In general terms the useful lives of general assets remained the same and the useful lives of distribution assets increased. For distribution assets the "Typical Useful Life" TUL (as defined in the Kinectrics study) are within the ranges reported by Kinectrics. The reasons for choosing the useful lives of assets was documented by KPMG in a conclusion document titled “Componentization and Depreciation”. This document is included as Appendix 4.3.

Table 4.28 Amortization Expense Summary

SUMMARY AMORTIZATION EXPENSE									
		2006	2007	2008	2009	2010	2011	2012 CGAAP	2012 IFRS
Account	Description	Amortization Expense	Amortization Expense	Amortization Expense	Amortization Expense	Amortization Expense	Amortization Expense	Amortization Expense	Amortization Expense
1805	Land								
1808	Buildings								
1810	Leasehold Improvements								
1815	Transformer Station Equipment >50 kV								
1820	Distribution Station Equipment <50 kV								
1825	Storage Battery Equipment								
1830	Poles, Towers & Fixtures	249,535	261,206	269,006	295,397	283,241	298,305	287,068	116,944
1835	Overhead Conductors & Devices	44,726	54,104	61,043	71,861	84,631	93,260	96,144	38,103
1840	Underground Conduit	173,141	183,426	183,430	165,590	195,455	189,268	186,983	55,059
1845	Underground Conductors & Devices	40,980	50,856	55,345	55,591	72,132	77,003	78,544	33,771
1850	Line Transformers	219,874	238,448	247,136	259,090	290,483	298,740	299,422	177,508
1855	Services (Overhead and Underground)	41,540	54,314	58,743	74,743	76,215	78,372	78,881	9,877
1860	Meters	42,323	44,104	46,168	55,114	20,231	14,752	14,897	9,527
1860	Meters (Smart Meters)								100,621
1905	Land								
1906	Land Rights								
1908	Buildings & Fixtures	12,457	12,457	12,457	13,711	11,212	12,457	12,457	12,457
1908	Buildings & Fixtures	1,075	1,075	1,138	2,811	758	1,406	1,406	1,406
1908	Buildings & Fixtures	217	217	217	435	2,847	5,964	7,616	7,805
1910	Leasehold Improvements								
1915	Office Furniture & Equipment (10 Years)	6,142	4,848	4,580	5,116	5,028	4,995	3,925	3,925
1915	Office Furniture & Equipment (5 Years)								
1920	Computer Equipment - Hardware	21,257	5,255	10,963	17,115	18,161	21,102	17,131	10,278
1925	Computer Software	73,549	51,899	39,945	46,854	72,219	102,154	100,237	100,237
1930	Transportation Equipment	32,033	36,467	33,306	48,050	22,806	16,982	42,446	14,149
1935	Stores Equipment								
1940	Tools, Shop & Garage Equipment	7,248	8,072	7,138	8,544	9,790	8,272	6,959	6,959
1945	Measurement & Testing Equipment	3,662	3,883	5,860	9,464	9,038	7,845	5,970	5,970
1950	Power Operated Equipment								
1955	Communications Equipment							1,185	2,370
1955	Communication Equipment (Smart Meters)								2,134
1960	Miscellaneous Equipment								
1975	Load Management Controls Utility Premises								
1980	System Supervisor Equipment								
1985	Miscellaneous Fixed Assets								
1995	Contributions & Grants	- 117,367	- 154,639	- 161,164	- 161,945	- 199,080	- 205,088	- 208,088	
2055	Construciton Work in Progress								
	Total	**852,392**	**855,993**	**875,311**	**967,542**	**975,166**	**1,025,789**	**1,033,182**	**709,099**

Details of Grimsby Power Inc.’s depreciation by account number are provided in Tables 4.29 through 4.36.

DEPRECIATION EXPENSE TABLES (BOARD APPENDIX 2-M)

Table 4.29 Depreciation Expense – 2006

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (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)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land			$ -		$ -				
1808	Buildings			$ -		$ -				
1810	Leasehold Improvements			$ -		$ -				
1815	Transformer Station Equipment >50 kV			$ -		$ -				
1820	Distribution Station Equipment <50 kV	$ 143,555	$ 143,555	$ -		$ -				
1825	Storage Battery Equipment			$ -		$ -				
1830	Poles, Towers & Fixtures	$ 6,211,841	$ 60,898	$ 6,150,943	$ 87,439	$ 6,238,382	25.00	4.00%	$ 249,535	No
1835	Overhead Conductors & Devices	$ 1,105,752		$ 1,105,752	$ 12,401	$ 1,118,153	25.00	4.00%	$ 44,726	No
1840	Underground Conduit	$ 4,508,023	$ 209,971	$ 4,298,052	$ 30,476	$ 4,328,528	25.00	4.00%	$ 173,141	No
1845	Underground Conductors & Devices	$ 847,894		$ 847,894	$ 176,600	$ 1,024,494	25.00	4.00%	$ 40,980	No
1850	Line Transformers	$ 5,513,820	$ 373,849	$ 5,139,971	$ 356,872	$ 5,496,843	25.00	4.00%	$ 219,874	No
1855	Services (Overhead and Underground)	$ 951,051		$ 951,051	$ 86,946	$ 1,038,489	25.00	4.00%	$ 41,540	No
1860	Meters	$ 1,215,046	$ 202,682	$ 1,012,364	$ 45,710	$ 1,058,074	25.00	4.00%	$ 42,323	No
1860	Meters (Smart Meters)			$ -		$ -				
1905	Land	$ 111,556		$ 111,556		$ 111,556				
1906	Land Rights			$ -		$ -				
1908	Buildings & Fixtures	$ 622,852		$ 622,852		$ 622,852	50.00	2.00%	$ 12,457	No
1908	Buildings & Fixtures	$ 51,275		$ 51,275		$ 51,275	40.00	2.50%	$ 1,075	No
1908	Buildings & Fixtures	$ 5,431		$ 5,431		$ 5,431	25.00	4.00%	$ 217	No
1910	Leasehold Improvements			$ -		$ -				
1915	Office Furniture & Equipment (10 Years)	$ 120,271	$ 80,981	$ 39,290	$ 22,134	$ 61,424	10.00	10.00%	$ 6,142	No
1915	Office Furniture & Equipment (5 Years)			$ -		$ -				
1920	Computer Equipment - Hardware	$ 282,395	$ 234,363	$ 48,032	$ 15,738	$ 63,770	3.00	33.33%	$ 21,257	No
1925	Computer Software	$ 239,207	$ 999	$ 238,208	$ 129,534	$ 367,743	5.00	20.00%	$ 73,549	No
1930	Transportation Equipment	$ 724,424	$ 590,667	$ 133,757	$ 26,409	$ 160,167	5.00	20.00%	$ 32,033	No
1935	Stores Equipment	$ 47,652	$ 47,652	$ -		$ -				
1940	Tools, Shop & Garage Equipment	$ 134,139	$ 61,659	$ 72,480		$ 72,480	10.00	10.00%	$ 7,248	No
1945	Measurement & Testing Equipment	$ 53,333	$ 35,023	$ 18,310		$ 18,310	5.00	20.00%	$ 3,662	No
1950	Power Operated Equipment			$ -		$ -				
1955	Communications Equipment	$ 9,002	$ 9,002	$ -		$ -				
1955	Communication Equipment (Smart Meters)			$ -		$ -				
1960	Miscellaneous Equipment			$ -		$ -				
1975	Load Management Controls Utility Premises			$ -		$ -				
1980	System Supervisor Equipment			$ -		$ -				
1985	Miscellaneous Fixed Assets			$ -		$ -				
1995	Contributions & Grants	-$ 2,821,350	$ 6,646	-$ 2,827,996	-$ 106,169	-$ 2,934,164	25.00	4.00%	-$ 117,367	No
etc.				$ -		$ -				
				$ -		$ -				
	Total	$ 20,077,171	$ 2,057,948	$ 18,019,223	$ 884,091	$ 18,903,806			$ 852,392	

Table 4.30 Depreciation Expense – 2007

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (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)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ -		$ -	$ -	$ -				
1808	Buildings	$ -		$ -	$ -	$ -				
1810	Leasehold Improvements	$ -		$ -	$ -	$ -				
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -				
1820	Distribution Station Equipment <50 kV	$ 143,555	$ 143,555	$ -	$ -	$ -				
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -				
1830	Poles, Towers & Fixtures	$ 6,299,280	$ 76,919	$ 6,222,361	$ 307,783	$ 6,530,144	25.00	4.00%	$ 261,206	No
1835	Overhead Conductors & Devices	$ 1,118,153		$ 1,118,153	$ 234,282	$ 1,352,596	25.00	4.00%	$ 54,104	No
1840	Underground Conduit	$ 4,538,499	$ 210,101	$ 4,328,398	$ 257,246	$ 4,585,644	25.00	4.00%	$ 183,426	No
1845	Underground Conductors & Devices	$ 1,024,494		$ 1,024,494	$ 246,900	$ 1,271,410	25.00	4.00%	$ 50,856	No
1850	Line Transformers	$ 5,870,692	$ 373,849	$ 5,496,843	$ 437,436	$ 5,961,212	25.00	4.00%	$ 238,448	No
1855	Services (Overhead and Underground)	$ 1,037,996		$ 1,037,996	$ 320,307	$ 1,357,861	25.00	4.00%	$ 54,314	No
1860	Meters	$ 1,260,756	$ 205,090	$ 1,055,666	$ 46,935	$ 1,102,601	25.00	4.00%	$ 44,104	No
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -				
1905	Land	$ 111,556		$ 111,556	$ -	$ 111,556				
1906	Land Rights	$ -		$ -	$ -	$ -				
1908	Buildings & Fixtures	$ 622,852		$ 622,852	$ -	$ 622,852	50.00	2.00%	$ 12,457	No
1908	Buildings & Fixtures	$ 51,275		$ 51,275	$ -	$ 51,275	40.00	2.50%	$ 1,075	No
1908	Buildings & Fixtures	$ 5,431		$ 5,431	$ -	$ 5,431	25.00	4.00%	$ 217	No
1910	Leasehold Improvements	$ -		$ -	$ -	$ -				
1915	Office Furniture & Equipment (10 Years)	$ 132,873	$ 84,393	$ 48,480	$ -	$ 48,480	10.00	10.00%	$ 4,848	No
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -				
1920	Computer Equipment - Hardware	$ 298,133	$ 279,229	$ 18,904	-$ 3,138	$ 15,766	3.00	33.33%	$ 5,255	No
1925	Computer Software	$ 368,742	$ 130,897	$ 237,845	$ 21,649	$ 259,495	5.00	20.00%	$ 51,899	No
1930	Transportation Equipment	$ 731,819	$ 571,656	$ 160,163	$ 22,173	$ 182,336	5.00	20.00%	$ 36,467	No
1935	Stores Equipment	$ 47,652	$ 47,652	$ -	$ -	$ -				No
1940	Tools, Shop & Garage Equipment	$ 134,139	$ 64,446	$ 69,694	$ 11,025	$ 80,719	10.00	10.00%	$ 8,072	No
1945	Measurement & Testing Equipment	$ 53,333	$ 50,104	$ 3,230	$ 16,186	$ 19,416	5.00	20.00%	$ 3,883	No
1950	Power Operated Equipment	$ -		$ -	$ -	$ -				
1955	Communications Equipment	$ -		$ -	$ -	$ -				
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -				
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -				
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -				
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -				
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -				
1995	Contributions & Grants	-$ 2,927,518	$ 6,550	-$ 2,934,068	-$ 931,914	-$ 3,865,982	25.00	4.00%	-$ 154,639	No
2055	Construciton Work in Progress	$ -		$ -	$ 66,483	$ 66,483				
		$ -		$ -	$ -	$ -				
	Total	$ 20,923,713	$ 2,244,440	$ 18,679,273	$ 1,053,354	$ 19,205,950			$ 855,993	

Table 4.31 Depreciation Expense – 2008

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (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)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ -		$ -	$ -	$ -				
1808	Buildings	$ -		$ -	$ -	$ -				
1810	Leasehold Improvements	$ -		$ -	$ -	$ -				
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -				
1820	Distribution Station Equipment <50 kV	$ 143,555	$ 143,555	$ -	$ -	$ -				
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -				
1830	Poles, Towers & Fixtures	$ 6,607,063	$ 133,960	$ 6,473,103	$ 252,040	$ 6,725,143	25.00	4.00%	$ 269,006	No
1835	Overhead Conductors & Devices	$ 1,352,435		$ 1,352,435	$ 173,651	$ 1,526,087	25.00	4.00%	$ 61,043	No
1840	Underground Conduit	$ 4,795,744	$ 210,101	$ 4,585,644	$ -	$ 4,585,753	25.00	4.00%	$ 183,430	No
1845	Underground Conductors & Devices	$ 1,271,395		$ 1,271,395	$ 112,392	$ 1,383,621	25.00	4.00%	$ 55,345	No
1850	Line Transformers	$ 6,308,128	$ 418,920	$ 5,889,208	$ 289,202	$ 6,178,410	25.00	4.00%	$ 247,136	No
1855	Services (Overhead and Underground)	$ 1,358,304		$ 1,358,304	$ 110,419	$ 1,468,575	25.00	4.00%	$ 58,743	No
1860	Meters	$ 1,307,691	$ 208,147	$ 1,099,543	$ 54,644	$ 1,154,188	25.00	4.00%	$ 46,168	No
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -				
1905	Land	$ 111,556		$ 111,556	$ -	$ 111,556				
1906	Land Rights	$ -		$ -	$ -	$ -				
1908	Buildings & Fixtures	$ 622,852		$ 622,852		$ 622,852	50.00	2.00%	$ 12,457	No
1908	Buildings & Fixtures	$ 51,275		$ 51,275	$ 3,799	$ 55,074	40.00	2.50%	$ 1,138	No
1908	Buildings & Fixtures	$ 5,431		$ 5,431		$ 5,431	25.00	4.00%	$ 217	No
1910	Leasehold Improvements	$ -		$ -	$ -	$ -				
1915	Office Furniture & Equipment (10 Years)	$ 130,103	$ 92,174	$ 37,929	$ 7,870	$ 45,798	10.00	10.00%	$ 4,580	No
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -				
1920	Computer Equipment - Hardware	$ 266,277	$ 242,045	$ 24,232	$ 8,656	$ 32,889	3.00	33.33%	$ 10,963	No
1925	Computer Software	$ 387,418	$ 263,376	$ 124,042	$ 75,681	$ 199,723	5.00	20.00%	$ 39,945	No
1930	Transportation Equipment	$ 735,401	$ 578,878	$ 156,523	$ 10,009	$ 166,532	5.00	20.00%	$ 33,306	No
1935	Stores Equipment	$ 47,086	$ 47,086	$ -	$ -	$ -				No
1940	Tools, Shop & Garage Equipment	$ 112,473	$ 46,662	$ 65,811	$ 5,570	$ 71,381	10.00	10.00%	$ 7,138	No
1945	Measurement & Testing Equipment	$ 61,786	$ 32,487	$ 29,299	$ -	$ 29,299	5.00	20.00%	$ 5,860	No
1950	Power Operated Equipment	$ -		$ -	$ -	$ -				
1955	Communications Equipment	$ -		$ -	$ -	$ -				
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -				
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -				
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -				
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -				
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -				
1995	Contributions & Grants	-$ 3,859,433	$ 7,057	-$ 3,866,490	-$ 162,610	-$ 4,029,100	25.00	4.00%	-$ 161,164	No
2055	Construciton Work in Progress	$ 66,483		$ 66,483	$ 23,653	$ 90,136				
		$ -		$ -	$ -	$ -				
	Total	$ 21,883,023	$ 2,424,448	$ 19,458,575	$ 964,976	$ 19,941,063			$ 875,311	

Table 4.32 Depreciation Expense – 2009

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (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)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ -		$ -	$ -	$ -				
1808	Buildings	$ -		$ -	$ -	$ -				
1810	Leasehold Improvements	$ -		$ -	$ -	$ -				
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -				
1820	Distribution Station Equipment <50 kV	$ 143,555	$ 143,555	$ -	$ -	$ -				
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -				
1830	Poles, Towers & Fixtures	$ 6,859,102	$ 133,960	$ 6,725,143	$ 267,602	$ 7,384,920	25.00	4.00%	$ 295,397	No
1835	Overhead Conductors & Devices	$ 1,526,087		$ 1,526,087	$ 270,594	$ 1,796,524	25.00	4.00%	$ 71,861	No
1840	Underground Conduit	$ 4,795,744	$ 224,512	$ 4,571,232	$ 22,598	$ 4,139,761	25.00	4.00%	$ 165,590	No
1845	Underground Conductors & Devices	$ 1,383,787		$ 1,383,787	$ 144,476	$ 1,389,777	25.00	4.00%	$ 55,591	No
1850	Line Transformers	$ 6,597,330	$ 157,235	$ 6,440,094	$ 278,085	$ 6,477,255	25.00	4.00%	$ 259,090	No
1855	Services (Overhead and Underground)	$ 1,468,723		$ 1,468,723	$ 138,613	$ 1,868,577	25.00	4.00%	$ 74,743	No
1860	Meters	$ 1,362,335	$ 208,147	$ 1,154,188	$ 209,248	$ 1,377,848	25.00	4.00%	$ 55,114	No
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -				
1905	Land	$ 111,556		$ 111,556	$ -	$ 111,556				
1906	Land Rights	$ -		$ -	$ -	$ -				
1908	Buildings & Fixtures	$ 622,852		$ 622,852		$ 622,852	50.00	2.00%	$ 13,711	No
1908	Buildings & Fixtures	$ 55,074		$ 55,074	$ 1,149	$ 56,223	40.00	2.50%	$ 2,811	No
1908	Buildings & Fixtures	$ 5,431		$ 5,431		$ 5,431	25.00	4.00%	$ 435	No
1910	Leasehold Improvements	$ -		$ -	$ -	$ -				
1915	Office Furniture & Equipment (10 Years)	$ 137,973	$ 86,810	$ 51,163	$ -	$ 51,163	10.00	10.00%	$ 5,116	No
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -				
1920	Computer Equipment - Hardware	$ 269,378	$ 249,979	$ 19,399	$ 31,946	$ 51,344	3.00	33.33%	$ 17,115	No
1925	Computer Software	$ 463,099	$ 371,628	$ 91,471	$ 142,796	$ 234,268	5.00	20.00%	$ 46,854	No
1930	Transportation Equipment	$ 745,411	$ 526,954	$ 218,456	$ 21,795	$ 240,252	5.00	20.00%	$ 48,050	No
1935	Stores Equipment	$ 47,086	$ 47,086	$ -	$ -	$ -				No
1940	Tools, Shop & Garage Equipment	$ 118,043	$ 37,730	$ 80,313	$ 5,130	$ 85,443	10.00	10.00%	$ 8,544	No
1945	Measurement & Testing Equipment	$ 61,786	$ 17,479	$ 44,306	$ 3,014	$ 47,321	5.00	20.00%	$ 9,464	No
1950	Power Operated Equipment	$ -		$ -	$ -	$ -				
1955	Communications Equipment	$ -		$ -	$ -	$ -				
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -				
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -				
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -				
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -				
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -				
1995	Contributions & Grants	-$ 4,022,043	$ 7,057	-$ 4,029,100	-$ 87,808	-$ 4,048,616	25.00	4.00%	-$ 161,945	No
2055	Construciton Work in Progress	$ 90,136		$ 90,136	-$ 90,136	$ -				
		$ -		$ -	$ -	$ -				
	Total	$ 22,842,444	$ 2,212,133	$ 20,630,310	$ 1,359,103	$ 21,309,862			$ 967,542	

Table 4.33 Depreciation Expense – 2010

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (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)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ -		$ -	$ -	$ -				
1808	Buildings	$ -		$ -	$ -	$ -				
1810	Leasehold Improvements	$ -		$ -	$ -	$ -				
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -				
1820	Distribution Station Equipment <50 kV	$ 143,555	$ 143,555	$ -	$ -	$ -				
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -				
1830	Poles, Towers & Fixtures	$ 7,126,704	$ 391,241	$ 6,735,463	$ 345,562	$ 7,081,025	25.00	4.00%	$ 283,241	No
1835	Overhead Conductors & Devices	$ 1,796,681		$ 1,796,681	$ 319,085	$ 2,115,766	25.00	4.00%	$ 84,631	No
1840	Underground Conduit	$ 4,818,342	$ 224,512	$ 4,593,830	$ 292,541	$ 4,886,371	25.00	4.00%	$ 195,455	No
1845	Underground Conductors & Devices	$ 1,528,262		$ 1,528,262	$ 275,188	$ 1,803,299	25.00	4.00%	$ 72,132	No
1850	Line Transformers	$ 6,875,415	$ 157,235	$ 6,718,179	$ 543,894	$ 7,262,073	25.00	4.00%	$ 290,483	No
1855	Services (Overhead and Underground)	$ 1,607,336		$ 1,607,336	$ 298,045	$ 1,905,381	25.00	4.00%	$ 76,215	No
1860	Meters	$ 1,571,583	$ 1,142,671	$ 428,912	$ 76,855	$ 505,768	25.00	4.00%	$ 20,231	No
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -				
1905	Land	$ 111,556		$ 111,556	$ -	$ 111,556				
1906	Land Rights	$ -		$ -	$ -	$ -				
1908	Buildings & Fixtures	$ 622,852		$ 622,852		$ 622,852	50.00	2.00%	$ 11,212	No
1908	Buildings & Fixtures	$ 56,223		$ 56,223		$ 56,223	40.00	2.50%	$ 758	No
1908	Buildings & Fixtures	$ 5,431		$ 5,431	$ 71,174	$ 76,605	25.00	4.00%	$ 2,847	No
1910	Leasehold Improvements	$ -		$ -	$ -	$ -				
1915	Office Furniture & Equipment (10 Years)	$ 131,122	$ 87,895	$ 43,227	$ 7,053	$ 50,280	10.00	10.00%	$ 5,028	No
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -				
1920	Computer Equipment - Hardware	$ 119,997	$ 79,878	$ 40,119	$ 14,365	$ 54,484	3.00	33.33%	$ 18,161	No
1925	Computer Software	$ 434,101	$ 106,127	$ 327,974	$ 33,120	$ 361,094	5.00	20.00%	$ 72,219	No
1930	Transportation Equipment	$ 744,667	$ 631,566	$ 113,102	$ 926	$ 114,028	5.00	20.00%	$ 22,806	No
1935	Stores Equipment	$ 47,086	$ 47,086	$ -	$ -	$ -				No
1940	Tools, Shop & Garage Equipment	$ 118,530	$ 58,774	$ 59,756	$ 38,148	$ 97,905	10.00	10.00%	$ 9,790	No
1945	Measurement & Testing Equipment	$ 64,800	$ 25,259	$ 39,541	$ 5,648	$ 45,189	5.00	20.00%	$ 9,038	No
1950	Power Operated Equipment	$ -		$ -	$ -	$ -				
1955	Communications Equipment	$ -		$ -	$ -	$ -				
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -				
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -				
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -				
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -				
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -				
1995	Contributions & Grants	-$ 4,109,851	$ 7,057	-$ 4,116,908	-$ 867,342	-$ 4,984,250	25.00	4.00%	-$ 199,080	No
2055	Construciton Work in Progress	$ -		$ -	$ 4,740	$ 4,740				
		$ -		$ -	$ -	$ -				
	Total	$ 23,814,394	$ 3,102,856	$ 20,711,538	$ 1,459,002	$ 21,441,039			$ 975,166	

Table 4.34 Depreciation Expense – 2011

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (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)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ -		$ -	$ -	$ -				
1808	Buildings	$ -		$ -	$ -	$ -				
1810	Leasehold Improvements	$ -		$ -	$ -	$ -				
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -				
1820	Distribution Station Equipment <50 kV	$ 143,555	$ 143,555	$ -	$ -	$ -				
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -				
1830	Poles, Towers & Fixtures	$ 7,472,266	$ 519,929	$ 6,952,337	$ 505,277	$ 7,457,614	25.00	4.00%	$ 298,305	No
1835	Overhead Conductors & Devices	$ 2,115,766		$ 2,115,766	$ 215,534	$ 2,331,500	25.00	4.00%	$ 93,260	
1840	Underground Conduit	$ 5,110,882	$ 394,193	$ 4,716,690	$ 15,000	$ 4,731,690	25.00	4.00%	$ 189,268	No
1845	Underground Conductors & Devices	$ 1,803,450		$ 1,803,450	$ 121,408	$ 1,925,075	25.00	4.00%	$ 77,003	No
1850	Line Transformers	$ 7,419,309	$ 284,192	$ 7,135,116	$ 333,391	$ 7,468,507	25.00	4.00%	$ 298,740	No
1855	Services (Overhead and Underground)	$ 1,905,381		$ 1,905,381	$ 54,140	$ 1,959,300	25.00	4.00%	$ 78,372	No
1860	Meters	$ 388,952	$ 23,950	$ 365,002	$ 3,803	$ 368,805	25.00	4.00%	$ 14,752	No
1905	Land	$ 111,556		$ 111,556	$ -	$ 111,556				
1906	Land Rights	$ -		$ -	$ -	$ -				
1908	Buildings & Fixtures	$ 622,852		$ 622,852		$ 622,852	50.00	2.00%	$ 12,457	No
1908	Buildings & Fixtures	$ 56,223		$ 56,223		$ 56,223	40.00	2.50%	$ 1,406	No
1908	Buildings & Fixtures	$ 76,605		$ 76,605	$ 77,240	$ 149,105	25.00	4.00%	$ 5,964	No
1910	Leasehold Improvements	$ -		$ -	$ -	$ -				
1915	Office Furniture & Equipment (10 Years)	$ 137,239	$ 87,289	$ 49,950	$ -	$ 49,950	10.00	10.00%	$ 4,995	No
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -				
1920	Computer Equipment - Hardware	$ 129,178	$ 77,371	$ 51,807	$ 11,500	$ 63,307	3.00	33.33%	$ 21,102	No
1925	Computer Software	$ 467,221	$ 178,952	$ 288,270	$ 222,500	$ 510,770	5.00	20.00%	$ 102,154	No
1930	Transportation Equipment	$ 745,593	$ 690,684	$ 54,909	$ 30,000	$ 84,909	5.00	20.00%	$ 16,982	No
1935	Stores Equipment	$ 47,086	$ 47,086	$ -	$ -	$ -				No
1940	Tools, Shop & Garage Equipment	$ 156,678	$ 73,956	$ 82,723	$ -	$ 82,723	10.00	10.00%	$ 8,272	No
1945	Measurement & Testing Equipment	$ 70,448	$ 36,225	$ 34,224	$ 5,000	$ 39,224	5.00	20.00%	$ 7,845	No
1950	Power Operated Equipment	$ -		$ -	$ -	$ -				
1955	Communications Equipment	$ -		$ -	$ -	$ -				
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -				
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -				
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -				
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -				
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -				
1995	Contributions & Grants	-$ 4,977,193	$ 7,057	-$ 4,984,250	-$ 150,000	-$ 5,127,200	25.00	4.00%	-$ 205,088	No
2055	Construciton Work in Progress	$ 4,740		$ 4,740	-$ 4,740	$ -				
		$ -		$ -	$ -	$ -				
	Total	$ 24,007,789	$ 2,564,439	$ 21,443,350	$ 1,440,053	$ 22,163,377			$ 1,025,789	

Table 4.35 Depreciation Expense – 2012 (CGAAP)

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ -		$ -	$ -	$ -				
1808	Buildings	$ -		$ -	$ -	$ -				
1810	Leasehold Improvements	$ -		$ -	$ -	$ -				
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -				
1820	Distribution Station Equipment <50 kV	$ 143,555	$ 143,555	$ -	$ -	$ -				
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -				
1830	Poles, Towers & Fixtures	$ 7,977,543	$ 924,182	$ 7,053,361	$ 246,699	$ 7,176,710	25.00	4.00%	$ 287,068	No
1835	Overhead Conductors & Devices	$ 2,331,300	$ 72,373	$ 2,258,927	$ 289,322	$ 2,403,588	25.00	4.00%	$ 96,144	No
1840	Underground Conduit	$ 5,125,882	$ 451,301	$ 4,674,581	$ -	$ 4,674,581	25.00	4.00%	$ 186,983	No
1845	Underground Conductors & Devices	$ 1,924,858	$ 38,570	$ 1,886,288	$ 154,611	$ 1,963,594	25.00	4.00%	$ 78,544	No
1850	Line Transformers	$ 7,752,700	$ 388,283	$ 7,364,416	$ 242,292	$ 7,485,562	25.00	4.00%	$ 299,422	No
1855	Services (Overhead and Underground)	$ 1,959,521	$ 12,615	$ 1,946,906	$ 50,225	$ 1,972,019	25.00	4.00%	$ 78,881	No
1860	Meters	$ 368,921	$ 3,439	$ 365,481	$ 13,910	$ 372,436	25.00	4.00%	$ 14,897	No
1860	Meters (Smart Meters)									
1905	Land	$ 111,556		$ 111,556	$ -	$ 111,556				
1906	Land Rights	$ -		$ -	$ -	$ -				
1908	Buildings & Fixtures	$ 622,852		$ 622,852	$ -	$ 622,852	50.00	2.00%	$ 12,457	No
1908	Buildings & Fixtures	$ 56,223		$ 56,223		$ 56,223	40.00	2.50%	$ 1,406	No
1908	Buildings & Fixtures	$ 153,846		$ 153,846	$ 82,570	$ 190,390	25.00	4.00%	$ 7,616	No
1910	Leasehold Improvements	$ -		$ -	$ -	$ -				
1915	Office Furniture & Equipment (10 Years)	$ 137,239	$ 97,986	$ 39,253	$ -	$ 39,253	10.00	10.00%	$ 3,925	No
1915	Office Furniture & Equipment (5 Years)	$ -		$ -	$ -	$ -				
1920	Computer Equipment - Hardware	$ 140,678	$ 98,212	$ 42,467	$ 17,850	$ 51,392	3.00	33.33%	$ 17,131	No
1925	Computer Software	$ 689,721	$ 201,014	$ 488,708	$ 24,950	$ 501,183	5.00	20.00%	$ 100,237	No
1930	Transportation Equipment	$ 764,820	$ 702,090	$ 62,731	$ 299,000	$ 212,231	5.00	20.00%	$ 42,446	No
1935	Stores Equipment	$ 47,086	$ 47,086	$ -	$ -	$ -				No
1940	Tools, Shop & Garage Equipment	$ 156,678	$ 87,890	$ 68,789	$ 1,600	$ 69,589	10.00	10.00%	$ 6,959	No
1945	Measurement & Testing Equipment	$ 75,448	$ 45,600	$ 29,849	$ -	$ 29,849	5.00	20.00%	$ 5,970	No
1950	Power Operated Equipment	$ -		$ -	$ -	$ -				
1955	Communications Equipment	$ -		$ -	$ 23,700	$ 11,850	10.00	10.00%	$ 1,185	No
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -				
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -				
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -				
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -				
1995	Contributions & Grants	-$ 5,127,193	$ 7,057	-$ 5,134,250	-$ 150,000	-$ 5,202,200	25.00	4.00%	-$ 208,088	No
2055	Construciton Work in Progress	$ -		$ -	$ -	$ -				
	Subtotal	$ 25,413,236	$ 3,321,253	$ 22,091,982	$ 1,296,729	$ 22,740,347			$ 1,033,182	
1860	Meters (Smart Meters)	$ 1,499,556		$ 1,499,556	$ 20,920	$ 1,510,016	15.00	6.67%	$ 100,668	No
1955	Communication Equipment (Smart Meters)	$ 10,669		$ 10,669	$ -	$ 10,669	5.00	20.00%	$ 2,134	No
	Total	$ 26,923,461	$ 3,321,253	$ 23,602,208	$ 1,317,649	$ 24,261,032			$ 1,135,984	

Table 4.36 Depreciation Expense – 2012 (IFRS)

Account	Description	2011 Closing Balance	Capital Contribution Allocations	2012 Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ -		$ -		$ -	$ -	$ -				
1808	Buildings	$ -		$ -		$ -	$ -	$ -				
1810	Leasehold Improvements	$ -		$ -		$ -	$ -	$ -				
1815	Transformer Station Equipment >50 kV	$ -		$ -		$ -	$ -	$ -				
1820	Distribution Station Equipment <50 kV	$ 143,555		$ 143,555	$ 143,555	$ -	$ -	$ -				Yes
1825	Storage Battery Equipment	$ -		$ -		$ -	$ -	$ -				
1830	Poles, Towers & Fixtures	$ 7,977,543	-$ 138,912	$ 7,838,631	$ 924,182	$ 6,914,449	$ 204,352	$ 7,016,625	60.00	1.67%	$ 116,944	Yes
1835	Overhead Conductors & Devices	$ 2,331,300	-$ 94,162	$ 2,237,138	$ 72,373	$ 2,164,764	$ 242,816	$ 2,286,172	60.00	1.67%	$ 38,103	Yes
1840	Underground Conduit	$ 5,125,882	-$ 820,427	$ 4,305,456	$ 451,301	$ 3,854,154	$ -	$ 3,854,154	70.00	1.43%	$ 55,059	Yes
1845	Underground Conductors & Devices	$ 1,924,858	-$ 778,518	$ 1,146,340	$ 38,570	$ 1,107,771	$ 148,446	$ 1,181,994	35.00	2.86%	$ 33,771	Yes
1850	OH Line Transformers	$ 5,531,203	-$ 1,614,105	$ 3,917,098	$ 388,283	$ 3,528,815	$ 184,446	$ 3,621,038	35.00	2.86%	$ 103,458	Yes
1850	UG Line Transformers	$ 2,221,496		$ 2,221,496		$ 2,221,496		$ 2,221,496	30.00	3.33%	$ 74,050	Yes
1855	Services Overhead	$ 178,739		$ 178,739	$ 12,615	$ 166,124	$ 14,770	$ 173,509	60.00	1.67%	$ 2,892	Yes
1855	Services Underground	$ 1,780,782	-$ 1,515,815	$ 264,967		$ 264,967	$ 28,901	$ 279,417	40.00	2.50%	$ 6,985	Yes
1860	Meters (Residential)	$ 19,340		$ 19,340		$ 19,340	$ 13,910	$ 26,295	25.00	4.00%	$ 1,052	Yes
1860	Meters (Industrial/Commercial)	$ 255,478	-$ 165,254	$ 90,224	$ 3,439	$ 86,784	$ -	$ 86,784	15.00	6.67%	$ 5,786	Yes
1860	Meters (Other CT's & PT's	$ 94,103		$ 94,103		$ 94,103	$ -	$ 94,103	35.00	2.86%	$ 2,689	Yes
1860	Meters (Smart Meters)	$ 1,499,556		$ 1,499,556		$ 1,499,556	$ 19,529	$ 1,509,321	15.00	6.67%	$ 100,621	Yes
1905	Land	$ 111,556		$ 111,556		$ 111,556	$ -	$ 111,556				
1906	Land Rights	$ -		$ -		$ -	$ -	$ -				
1908	Buildings & Fixtures	$ 622,852		$ 622,852		$ 622,852	$ -	$ 622,852	50.00	2.00%	$ 12,457	Yes
1908	Buildings & Fixtures	$ 56,223		$ 56,223		$ 56,223	$ -	$ 56,223	40.00	2.50%	$ 1,406	Yes
1909	Buildings & Fixtures	$ 153,846		$ 153,846		$ 153,846	$ 82,570	$ 195,131	25.00	4.00%	$ 7,805	Yes
1910	Leasehold Improvements	$ -		$ -		$ -	$ -	$ -				
1915	Office Furniture & Equipment (10 Years)	$ 137,239		$ 137,239	$ 97,986	$ 39,253	$ -	$ 39,253	10.00	10.00%	$ 3,925	Yes
1915	Office Furniture & Equipment (5 Years)	$ -		$ -		$ -	$ -	$ -				
1920	Computer Equipment - Hardware	$ 140,678		$ 140,678	$ 98,212	$ 42,467	$ 17,850	$ 51,392	5.00	20.00%	$ 10,278	Yes
1925	Computer Software	$ 689,721		$ 689,721	$ 201,014	$ 488,708	$ 24,950	$ 501,183	5.00	20.00%	$ 100,237	Yes
1930	Transportation Equipment	$ 764,820		$ 764,820	$ 702,090	$ 62,731	$ 299,000	$ 212,231	15.00	6.67%	$ 14,149	Yes
1935	Stores Equipment	$ 47,086		$ 47,086	$ 47,086	$ -	$ -	$ -				
1940	Tools, Shop & Garage Equipment	$ 156,678		$ 156,678	$ 87,890	$ 68,789	$ 1,600	$ 69,589	10.00	10.00%	$ 6,959	Yes
1945	Measurement & Testing Equipment	$ 75,448		$ 75,448	$ 45,600	$ 29,849	$ -	$ 29,849	5.00	20.00%	$ 5,970	Yes
1950	Power Operated Equipment	$ -		$ -		$ -	$ -	$ -				
1955	Communications Equipment	$ -		$ -		$ -	$ 23,700	$ 11,850	5.00	20.00%	$ 2,370	Yes
1955	Communication Equipment (Smart Meters)	$ 10,669		$ 10,669		$ 10,669		$ 10,669	5.00	20.00%	$ 2,134	Yes
1960	Miscellaneous Equipment	$ -		$ -		$ -	$ -	$ -				
1975	Load Management Controls Utility Premises	$ -		$ -		$ -	$ -	$ -				
1980	System Supervisor Equipment	$ -		$ -		$ -	$ -	$ -				
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -	$ -	$ -				
1995	Contributions & Grants	-$ 5,127,193	$ 5,127,193	$ -		$ -	$ -	$ -				
2055	Construciton Work in Progress	$ -		$ -		$ -	$ -	$ -				
		$ -		$ -		$ -	$ -	$ -				
	Total	$ 26,923,461	$ -	$ 26,923,461	$ 3,314,196	$ 23,609,265	$ 1,306,840	$ 24,262,685			$ 709,099	

TAX CALCULATIONS

Grimsby Power Inc. has completed the tax calculations as per Page 32 Section 2.7.8 in the Filing Guidelines. Table 4.37 below provides a summary of 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual and 2010 Actual income taxes included in audited statements, 2011 Bridge Year estimate using current rates, and 2012 Test Year income taxes based on revised rates.

Table 4.37 Summary of Income Taxes

Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
Income Taxes	414,369	68,355	142,914	49,416	27,287	43,786	62,299
Ontario Capital Tax	9,545	3,374	-	-	1,534	-	-
Total Taxes	**423,914**	**71,729**	**142,914**	**49,416**	**28,821**	**43,786**	**62,299**

Grimsby Power Inc's detailed tax calculations using the most recent tax rates are provided in the following Table 4.38.

Table 4.38 Tax Calculations

ITEM	2006 ACTUAL	2007 ACTUAL	2008 ACTUAL	2009 ACTUAL	2010 ACTUAL	2011 BRIDGE	2012 TEST YEAR
Accounting Net Income Before Taxes	**441,144**	**396,408**	**446,449**	**359,899**	**271,459**	**109,545**	**688,331**
Additions:							
Provisions for Income Taxes - Current	639,164	123,852	219,356	- 625	82,162		
Provisions for Income Taxes - Deferred	- 433,430	119,000	- 59,000	131,123	98,229		
Amortization of Tangible Assets	852,391	855,993	875,310	967,541	975,166	1,025,789	709,099
Loss on Disposal of Assets	2,160		1,598	2,281	464		
Charitable Donations from Schedule 2				1,750	700		
Non-Deductible Meals and Entertainment Expenses	2,456	2,874	5,192	1,860	2,099		
Other Reserves from Schedules 13	295,611	339,053		320,162	353,898		
Reserves @ End of the Year	6,500	6,500	326,662	360,398	788,927	788,282	656,500
Subtotal of additions	1,364,852	1,447,272	1,369,118	1,784,490	2,301,645	1,814,071	1,365,599
Other Additions							
Regulatory Assets Closing Balance				1,025,023			
Capital Assets Additions Included in Regulatory Balance	1,261,893	-	1,363,742	181,194	1,523,395		
Subtotal of other additions	1,261,893	-	1,363,742	1,206,217	1,523,395	-	-
Total Additions:	**2,626,745**	**1,447,272**	**2,732,860**	**2,990,707**	**3,825,040**	**1,814,071**	**1,365,599**
Deductions							
Capital Cost Allowance from Schedule 8	876,794	857,816	841,414	1,034,576	940,431	1,112,120	1,170,499
Gain on Disposal of Assets	4,098	1,000					
Other Reserves from Schedules 13	295,611	333,209	320,162	353,898	781,782	656,500	481,500
Reserves @Beginning of the Year	6,500	6,500	6,500	326,662	360,398		
Subtotal of deductions	1,183,003	1,198,525	1,168,076	1,715,136	2,082,611	1,768,620	1,651,999
Other Deductions							
Variance Adjustment		293,795					
Regulatory Liability Opening Balance					1,025,025		
Regulatory Assets Opening Balance			1,255,757	1,362,813			
Regulatory Assets Closing Balance					854,128		
Ontario Capital Tax		-	-	-	1,534		
Subtotal of other deductions	-	293,795	1,255,757	1,362,813	1,880,687	-	-
Total Deductions:	**1,183,003**	**1,492,320**	**2,423,833**	**3,077,949**	**3,963,298**	**1,768,620**	**1,651,999**
Income for Tax Purpose	**1,884,886**	**351,360**	**755,476**	**272,657**	**133,201**	**154,996**	**401,931**
Tax Rate Reflecting Tax Credits (Federal+Provincial)	21.98%	19.45%	18.92%	18.12%	20.49%	28.25%	15.50%
Income Taxes	**414,369**	**68,355**	**142,914**	**49,416**	**27,287**	**43,786**	**62,299**
Capital Tax Calculation							
Total Rate Base	12,886,118	13,081,893	13,134,302	13,448,002	13,927,451	15,005,665	16,336,952
Reduction	- 9,142,535	- 11,401,612			- 11,224,500		
Rate	0.255%	0.201%	0.000%	0.000%	0.057%		
Capital Tax	**9,545**	**3,374**	**-**	**-**	**1,534**	**-**	**-**

2010 Federal and Ontario Tax Return

Grimsby Power Inc.'s 2010 Federal and Provincial tax returns are included as Appendix 4.1.

CAPITAL COST ALLOWANCE

Grimsby power Inc. is providing Capital Cost Allowance continuity schedules for the 2011 Bridge Year and 2012 Test Year in Tables 4.39 & 4.42 below.

Table 4.39 2011 CCA / UCC Continuity Schedule

CCA Continuity Schedule (2011)

Class	Class Description	UCC Prior Year Ending Balance	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr	1/2 Year Rule {1/2 Additions	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	9,120,636	9,120,636	0	0	9,120,636	0	9,120,636	4%	364,825	8,755,811
2	Distribution System - pre 1988	484,256	484,256	0	0	484,256	0	484,256	6%	29,055	455,201
6	Buildings (No footings below ground)		0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	291,742	291,742	5,000	0	296,742	2,500	294,242	20%	58,848	237,894
10	Computer Hardware/ Vehicles	61,278	61,278	41,500	10,773	92,005	15,364	76,642	30%	22,992	69,013
10.1	Certain Automobiles		0	0	0	0	0	0	30%	0	0
12	Computer Software	16,560	16,560	222,500	0	239,060	111,250	127,810	100%	127,810	111,250
3			0	0	0	0	0	0	5%	0	0
			0	0	0	0	0	0		0	0
13 3	Lease # 3		0	0	0	0	0	0		0	0
13 4	Lease # 4		0	0	0	0	0	0		0	0
14	Franchise		0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post	2,320	2,320	0	0	2,320	0	2,320	45%	1,044	1,276
50	Computers & Systems Hardware acq'd post	1,136	1,136	0	0	1,136	0	1,136	55%	625	511
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	5,760,515	5,760,515	1,175,793	23,834	6,912,475	575,980	6,336,495	8%	506,920	6,405,555
	SUB-TOTAL - UCC	**15,738,443**	**15,738,443**	**1,444,793**	**34,607**	**17,148,630**	**705,093**	**16,443,536**		**1,112,120**	**16,036,510**
				0	0						
CEC	Goodwill		0								
CEC	Land Rights		0								
CEC	FMV Bump-up		0								
	SUB-TOTAL - CEC	**0**	**0**								

Table 4.40 2012 CCA / UCC Continuity Schedule

Class	Class Description	UCC Prior Year Ending Balance	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	8,755,811	8,755,811	0	0	8,755,811	0	8,755,811	4%	350,232	8,405,578
2	Distribution System - pre 1988	455,201	455,201	0	0	455,201	0	455,201	6%	27,312	427,889
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	237,894	237,894	25,300	0	263,194	12,650	250,544	20%	50,109	213,085
10	Computer Hardware/ Vehicles	69,013	69,013	316,850	0	385,863	158,425	227,438	30%	68,231	317,631
10.1	Certain Automobiles	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	111,250	111,250	24,950	0	136,200	12,475	123,725	100%	123,725	12,475
3		0	0	0	0	0	0	0	5%	0	0
		0	0	0	0	0	0	0	0%	0	0
13 3	Lease # 3	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	1,276	1,276	0	0	1,276	0	1,276	45%	574	702
50	Computers & Systems Hardware acq'd post Mar 19/07	511	511	0	0	511	0	511	55%	281	230
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	6,405,555	6,405,555	939,740		7,345,295	469,870	6,875,425	8%	550,034	6,795,261
	SUB-TOTAL - UCC	**16,036,510**	**16,036,510**	**1,306,840**	**0**	**17,343,350**	**653,420**	**16,689,930**		**1,170,499**	**16,172,851**
				0	0						
CEC	Goodwill	0	0								
CEC	Land Rights	0	0								
CEC	FMV Bump-up	0	0								
	SUB-TOTAL - CEC	**0**	**0**								

Table 4.41 2012 CEC Continuity Schedule

Cumulative Eligible Capital Calculation		
Cumulative Eligible Capital		0
Additions:		
Cost of Eligible Capital Property Acquired during the year		
Other Adjustments		
Subtotal	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	
	0	0
Amount transferred on amalgamation or wind-up of subsidiary		0
Subtotal		0
Deductions:		
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year		
Other Adjustments		
Subtotal	0	0
Cumulative Eligible Capital Balance		0
CEC Deduction		0
Cumulative Eligible Capital - Closing Balance		0

GREEN ENERGY PLAN O&M COSTS

In accordance with OEB EB-2009-0397 filing requirements for Distribution System Plans – Filing under Deemed Conditions of License dated March 25, 2010 Grimsby Power Inc. is including its Basic GEA Plan with this filing as Appendix 4.4. As required this plan has been submitted to the OPA for review. The OPA's response in included as Appendix 4.5. Grimsby Power Inc. has included $27,204 in its 2012 budget allocated to Account 1532000 – Renewable Generation Connection Deferral Account – OM&A.

Grimsby Power Inc. is aware of the Boards requirement to determine the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09 in regards to the recovery of cost for a Distributor's Green Energy Act (GEA) Plan. The costs projected to be incurred by Grimsby Power in the 2012 Test Year and beyond are less than Grimsby Power Inc.'s materiality threshold of $50,000 and as such Grimsby Power Inc. is proposing to defer the disposition of this account.

CDM COSTS

Grimsby Power Inc. has not incurred CDM costs to be included in rate base. All CDM costs are directly funded by OPA programs.

Appendix 4.1 Grimsby Power Inc. – 2010 Federal and Ontario Tax Return

Canada Revenue Agency / Agence du revenu du Canada

Business Consent form

Complete this form to consent to the release of confidential information about your program account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre (see Instructions).** Make sure you complete this form correctly, since we cannot change the information that you provided. You can also give **or** cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount.**

Note: Read all the instructions before completing this form.

Part 1 – Business information

Complete this part to identify your business (all fields have to be completed)

Business name: Grimsby Power Incorporated

BN: 864874839 Telephone Number: (905) 945-5437

Part 2 – Authorize a representative

Complete either part a) or b)

a) Authorize access by telephone, fax, mail or in person by appointment

If you are giving consent for an individual, enter that person's full name. If you are giving consent to a firm, enter the name and BN of the firm. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the firm's name and BN. If you do not identify an individual of the firm, then you are giving us consent to deal with anyone from that firm.

Note: If you are authorizing a representative (individual or firm) who is not registered with the Represent a client service, the phone number is required.

Name of Individual:

Name of Firm:

Telephone number: Extension: **BN:**

OR

b) Authorize online access (includes access by telephone, fax, mail or by appointment)

You can authorize your representative to deal with us through our online service for representatives. The Business Number must be registered with the "Represent a Client" service to be an online representative. **Our online service does not have a year-specific option, so your representative will have access to all years.** Please enter the name and RepID of the individual **or** GroupID and name of the group **or** name and BN of the firm.

Name of Individual: **and** **RepID:**

OR

Name of Group: **and** **GroupID:** G

OR

Name of Firm: Deloitte & Touche LLP **and** **BN:** 133245290

Telephone Number: (519) 650-7600

Part 3 – Select the program accounts, years and authorization level

a) Program Accounts – Select the program accounts the above individual or firm is authorized to access (tick only box A **or** B).

A. [X] This authorization applies to all program accounts and all years.

Expiry date:

AND

Authorization Level (tick level 1 or 2)

[ ] Level 1 lets CRA disclose information only on your program account(s) **or**

[X] Level 2 lets CRA disclose information **and** accept changes to your program account(s).

OR

B. [ ] This authorization applies only to program accounts and periods listed in Part 3b). If you ticked this option, you must complete 3b).

Business Consent form (RC59 continued)

Part 3 – Select the program accounts, years and authorization level (continued)

b) Details of program accounts and fiscal periods – Complete this area only if you ticked box B in Part 3a) on page 1.

If you ticked box B in part 3a), you have to provide at least one program identifier (see Instructions on page 1). You can then tick the "All program accounts" box for that program identifier **or** enter a reference number. Provide the authorization level (tick **either** box 1 to disclose information or box 2 to disclose information **and** accept changes to your program account).

You can also tick the "All years" box to allow unlimited tax year access **or** enter a specific fiscal period (specific period authorization **is not available** for online access). You can also enter an expiry date to automatically cancel authorization. If more authorizations or more than four program identifiers are needed, complete another Form RC59.

Program identifier	All program accounts		Reference number	Authorization level 1	Authorization level 2	All years	or	Specific fiscal period (not available for online access) Year-end	Expiry date
		or					or		
		or					or		
		or					or		
		or					or		

Part 4 – Cancel one or more authorizations

Complete this part **only** to cancel authorization(s)

☐ **A.** Cancel **all** authorizations.

☐ **B.** Cancel authorization for the individual, group, or firm identified below.

☐ **C.** Cancel authorization for specific program account(s) ____________

Name of Individual: ____________ **and** **RepID:**

OR

Name of Group: ____________ **and** **GroupID:** G

OR

Name of Firm: ____________ **and** **BN:**

Part 5 – Certification

This form has to be signed by an authorized person of the business such as an owner, a partner of a partnership, a director of a corporation, an officer of a non-profit organization or a trustee of an estate. By signing and dating this form, you authorize the CRA to deal with the individual, group, or firm listed in Part 2 of this form or cancel the authorizations listed in Part 4.

First name: Doug Last name: Curtiss

Sign here ► ____________ Date 2011-08-08

We wil not process this form unless it is **signed** and **dated** by an authorized person of the business.

The *Privacy Act* protects information given on this form, which is kept in personal information bank numbers CRA PPU-175 and 223.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2011-12-31

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2011-01-31	2,274			2,274
2011-02-28	2,274			2,274
2011-03-31	2,274			2,274
2011-04-30	2,274			2,274
2011-05-31	2,274			2,274
2011-06-30	2,274			2,274
2011-07-31	2,274			2,274
2011-08-31	2,274			2,274
2011-09-30	2,274			2,274
2011-10-31	2,274			2,274
2011-11-30	2,274			2,274
2011-12-31	2,273			2,273
Total	27,287			27,287

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, 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** 86487 4839 RC0001

Corporation's name
002 Grimsby Power Incorporated

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.)
011 231 Roberts Road
012

City	Province, territory, or state
015 Grimsby	**016** ON
Country (other than Canada) **017**	Postal code/Zip code **018** L3M 5N2

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	Province, territory, or state
025	**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.)
031 231 Roberts Road
032

City	Province, territory, or state
035 Grimsby	**036** ON
Country (other than Canada) **037**	Postal code/Zip code **038** L3M 5N2

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** 2010-01-01 (YYYY MM DD) Tax year-end **061** 2010-12-31 (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.

		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	X	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	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	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		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
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		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

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? 282 ______
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity distribution	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any 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		133,201	A
Deduct: Charitable donations from Schedule 2	311	700		
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		700 ▶	700	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			132,501	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		132,501	
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)			132,501	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** 133,201 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 1/(.38 minus X**) 3.57143
times the amount on line 636***, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . **405** 132,501 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000 x Number of days in the tax year before 2009 / Number of days in the tax year 365 = ... 1

500,000 x Number of days in the tax year after 2008 365 / Number of days in the tax year 365 = ... 500,000 2

Add amounts at lines 1 and 2 500,000 4

Business limit (see notes 1 and 2 below) . . . . **410** 500,000 C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** **** 13,231 / 11,250 D = ... 588,044 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** F

Small business deduction

Amount A, B, C, or F whichever is the least x 17 % = ... **430** G

Enter amount G on line 1.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. This has to be pro-rated.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

****** Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			132,501	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")			132,501	H

Amount H	132,501	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=		I
Amount H	132,501	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=		J
Amount H	132,501	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	13,250 K
Amount H	132,501	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	L
Amount H	132,501	x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	L.1

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L.1 . . . 13,250 M

Enter amount M on line 638.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

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		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365 / 365	x	10 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 2012 / Number of days in the tax year	/ 365	x	11.5 %	=	W
Amount S		x	Number of days in the tax year after 2011 / Number of days in the tax year	/ 365	x	13 %	=	W.1

General tax reduction – Total of amounts T to W.1 . . . X

Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440		x 26 2/3 % =		A
Foreign non-business income tax credit from line 632					
Deduct: Foreign investment income from Schedule 7	445		x 9 1/3 % =		
			(if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360			132,501		
Deduct:					
Amount from line 400, 405, 410, or 425, whichever is the least					
Foreign non-business income tax credit from line 632		x 25 / 9 =			
Foreign business income tax credit from line 636		x 1(.38 - X*) / 3.57143 =			
			132,501		
			x 26 2/3 % =	35,334	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)				23,850	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450				F

* General rate reduction percentage for the tax year. This has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			
				G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
				H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3		x 1 / 3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)				

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 %			550	50,350	A
Recapture of investment tax credit from Schedule 31			602		B

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	132,501		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	132,501 ►	132,501	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		50,350	D

Deduct:

Small business deduction from line 430			1	
Federal tax abatement	608	13,250		
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	13,250		
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		26,500 ►	26,500	E

Part I tax payable – Line D **minus** line E	23,850	F

Enter amount F on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	23,850
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		23,850

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	3,437	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		3,437 ▶	3,437
Total tax payable	770		27,287 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	108,000	
Total credits	890	108,000 ▶	108,000 B

Refund code 894 1 Overpayment 80,713

Balance (line A minus line B) -80,713

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 [X] 2 No [ ]

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Certification

I, 950 Curtiss (Last name in block letters) 951 Doug (First name in block letters) 954 CEO (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 2011-08-08 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (905) 945-5437 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . 957 1 Yes [ ] 2 No [X]

958 Mioara Domokos (Name in block letters) 959 (905) 945-5437 (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

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Total instalments for 2010	108,000

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 108,000 **A**

Total instalments credited to the taxation year per T9 108,000 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	4,584,861	4,043,105
	Total tangible capital assets	2008	+	11,307,295	11,405,282
	Total accumulated amortization of tangible capital assets	2009	–		
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	2,002,393	1,214,359
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	17,894,549	16,662,746
	Liabilities				
	Total current liabilities	3139	+	4,154,080	2,628,731
	Total long-term liabilities	3450	+	7,577,852	8,142,857
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	11,731,932	10,771,588
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	6,162,617	5,891,158
	Total liabilities and shareholder equity	3640	=	17,894,549	16,662,746
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	309,149	37,690

* 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
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

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	+	18,747,911	16,765,862
	Cost of sales	8518	–	15,370,110	13,452,387
	Gross profit/loss	8519	=	3,377,801	3,313,475
	Cost of sales	8518	+	15,370,110	13,452,387
	Total operating expenses	9367	+	3,221,577	3,162,190
	Total expenses (mandatory field)	9368	=	18,591,687	16,614,577
	Total revenue (mandatory field)	8299	+	19,043,537	17,104,974
	Total expenses (mandatory field)	9368	–	18,591,687	16,614,577
	Net non-farming income	9369	=	451,850	490,397
	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	=	451,850	490,397
	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	–	82,162	-625
	Deferred income tax provision	9995	–	98,229	131,123
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	271,459	359,899

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation? . . . . . 095 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . 097 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . 099 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client) . . . . . 1 [X]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . 101 1 Yes [X] 2 No [ ]

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . 102 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . 103 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . . . 104 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . 105 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . 106 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . 107 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 108 1 Yes [ ] 2 No [X]

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . 109 1 Yes [ ] 2 No [ ]

Canada

T2 BAR CODE RETURN

Name: Grimsby Power Incorporated

BN: 86487 4839 RC 0001

Tax Year Start: 2010-01-01

Tax Year End: 2010-12-31

1. Nature of operations

Grimsby Power Incorporated (the "Company"), is incorporated under the laws of Ontario and its principal business activity is to distribute power to consumers within the Town of Grimsby.

The Company is a regulated electricity distribution Company that owns and operates the electricity infrastructure, distributing a safe, reliable delivery of electricity to homes and businesses in the Town of Grimsby. The Company is regulated by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, and for ensuring that distribution companies fulfill their obligations to connect and service customers.

2. Significant accounting policies

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and policies as set forth in the Accounting Procedures Manual issued by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998.

Significant accounting policies are summarized below:

Regulation

The Company is regulated by the OEB and any power rates adjustments require OEB approval. The following accounting policies under the regulated environment differ from GAAP for companies operating under an unregulated environment:

Regulatory assets and liabilities

Regulatory assets and liabilities represent differences between amounts collected through rates (OEB approved) and actual costs incurred by the distributor. Regulatory assets and liabilities on the balance sheet at year-end consist of Settlement Variances on the Cost of Power, Deferred Charges, and the associated regulated interest. Account balances and current year activities are detailed in Note 6.

Smart Meter Initiative

The Province of Ontario committed to having "Smart Meter" electricity meters installed in certain homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

The Corporation has installed 10,035 Smart Meters upon completion of its meter deployment.

Cash and cash equivalents

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

Unbilled revenue

Unbilled revenue is accrued from the last meter reading date to the end of the period.

Inventory

Inventory is valued at the lower of cost and net realizable value.

Capital assets and intangibles

Capital assets and intangibles are stated at cost. The cost and related accumulated amortization of the capital assets and finite lived intangibles are removed from the accounts at the end of their estimated service lives except in those instances where specific identification permits their removal at retirement or disposition. Gains and losses at retirement or disposition are credited or charged to income. Contributions in aid of capital assets and intangibles are recorded as deferred credits and amortized to income over the life of the related assets.

2. Significant accounting policies (continued)

Capital assets and intangibles (continued)

Contributions in aid of construction

Contributions in aid of construction consist of third party contributions toward the cost of constructing Company assets. Contributed capital has been charged to capital assets and recorded as an offset to capital assets.

Amortization is on a straight-line basis over 25 years.

Impairment of long-lived assets

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

Payments in lieu of taxes ("PILs")

The Company is currently exempt from taxes under the Income Tax Act (Canada) ("ITA") and the Taxation Act, 2007. Pursuant to the Electricity Act, 1998 (Ontario) (EA), the Company is required to compute taxes under the ITA and Taxation Act, 2007 and remit such amounts thereunder computed to the Ministry of Finance (Ontario).

The Company provides for PILs using the asset and liability method. Under this method, future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A future income tax asset recognized shall be limited to the amount that is more likely than not to be realized.

Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the Company at that time.

PILs recoverable from loss carry forwards are recorded in future payments in lieu of taxes on the balance sheet using the substantively enacted rates at the balance sheet date expected to apply when recovery of the loss carry forwards are expected to be recovered.

Customer and developer deposits

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

2. Significant accounting policies (continued)

Asset retirement obligations

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

Use of estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures related thereto. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements including changes as a result of future regulatory decisions.

Accounts receivable, unbilled revenue and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate valuation allowance. Inventory is recorded net of provisions for obsolescence. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

Revenue recognition

Revenue is recognized on the accrual basis, which includes an estimate of unbilled revenue. Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis on power used. Any discrepancies in the revenue collected and the associated cost of power to distribute are charged to regulatory assets.

Financial instruments

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

The Company has classified its financial instruments as follows:

Cash Held-for-trading

Accounts receivable Loans and receivables

Unbilled revenue Loans and receivables

Bank loan Other liabilities

Accounts payable and accrued liabilities Other liabilities

Promissory note Other liabilities

Customers' and developers' deposits Other liabilities

Held for trading

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

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

?

2. Significant accounting policies (continued)

Financial instruments (continued)

Loans and receivables

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

Other liabilities

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

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

Derivatives

The Company does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the presentation of these financial statements.

Future changes in accounting policies

International financial reporting standards (IFRS)

On February 13, 2008 the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the Company will apply IFRS to its financial statements for the year ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The Company continues to assess the impact of conversion to IFRS on its results of operations.

T2 BAR CODE RETURN

Name: Grimsby Power Incorporated

BN: 86487 4839 RC 0001

Tax Year Start: 2010-01-01

Tax Year End: 2010-12-31

3. Capital assets and intangibles

Intangible assets, representing computer software, is included in general equipment and intangibles and has an original cost of $467,221 (2009 - $434,101) and an accumulated amortization of $269,059 (2009 - $196,840). Amortization expense on intangible assets totaled $72,219 (2009 - $6,111). During the year, the Company received $153,456 (2009 - $130,482) of capital contributions in aid of construction.

4. Bank loan

The Company has available the following credit facilities with the bank:

" $1,000,000 operating loan to finance working capital, bearing interest at prime rate plus 0%, due on demand

" $964,845 letter of credit to satisfy IESO Prudential requirement, bearing interest at 0.6%, due on demand

" $1,600,000 operating demand loan to assist with 2010 capital expenditures, bearing interest at prime rate plus 0%, due on demand

" $1,600,000 committed reducing term loan by way of fixed rate term loan and floating rate term loan, fixed rate loan bearing interest at market rate as determined by the bank, floating rate loan bearing interest at prime rate plus 0.5%, fixed rate loan term up to 5 years, floating rate loan term up to 1 year

The credit facilities are secured by a General Security Agreement, assignment of fire insurance on inventory and equipment, assignment of liability insurance, and Postponement Agreement executed by the bank, the Company and the Town of Grimsby.

At December 31, 2010, the amount drawn on the credit facilities totaled $1,600,000 (2009 - nil).

5. Promissory note

The promissory note matures on February 1, 2020 and is payable to the Town of Grimsby. The note bears interest at the rate of 7.25% per annum.

6. Regulatory assets/liabilities

Net regulatory assets (liabilities) represent amounts recovered from customers in excess of costs incurred at OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future settlement in electricity distribution rates.

Management assesses the future uncertainty with respect to the recovery of those amounts, and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision concerning adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Regulatory assets (liabilities) incur interest at prescribed rates. In 2010, the rates ranged from 0.55% to 1.2% (2009 - 0.55% to 2.45%).

Settlement variances - represent amounts that have accumulated since Market Opening and comprise:

(a) Variances between amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the wholesale electricity market and grid, various wholesale market settlement charged and transmission charges, and the amounts billed to customers by the Company based on the OEB approved wholesale market service rate; and,

(b) Variances between the amounts charged by the IESO for energy commodity costs and the amounts billed to customers by the Company based on OEB approved rates.

Smart meters - The Province of Ontario has committed to have "Smart Meter" electricity meters installed in certain homes and small businesses by the end of 2008 and throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals. Bill 21, Energy Conservation and Responsibility Act, provides the legislative framework and regulations to support this initiative.

Included in distribution rates, effective May 1, 2006, is a charge for smart meters of $1.00 (2009 - $0.27) per metered customer per month. Consistent with the OEB's direction and pending further guidance, all smart meter related expenditures and recoveries are currently being deferred in regulatory accounts.

Regulatory assets recovery amount - represents costs incurred by the Company as of December 31, 2004 which have been approved for recovery through rates net of amounts recovered from customers.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates that the Company may charge and the costs that the Company may recover, including the balance of its regulatory assets.

In the absence of rate regulation, Canadian generally accepted accounting principles would require the Company to record the costs and recoveries described above in the operating results of the year in which they are incurred and reported earnings before income taxes would be $1,825,762 lower (2009 - $337,788 lower) than reported.

6. Regulatory liabilities (continued)

Rate regulation

The Company is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the Ontario Energy Board Act (1998). The OEB has the power and responsibility to approve or fix rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

In January 2000, the OEB established that distribution rates would be subject to Performance Based Regulation ("PBR"), a method of regulation whereby distribution rates are reduced annually to reflect productivity improvements required on the Company. Under this rate methodology, rates also include regulated amounts for return on Company equity and debt, which were initially determined by the OEB to be 9.88% and 7.25%, respectively. While the initial PBR regulatory framework provided for those regulatory rates of return, subsequent regulation and Provincial Government initiatives prevented distribution companies from fully achieving the theoretical rate of return on equity.

In 2005, the Company filed rate applications to adjust its distribution charges to provide for the full theoretical regulatory rate of return of 9.88% and continued recovery of its regulatory assets. As mandated by the OEB, the rate increase is subject to a financial commitment by the Company to invest $221,745 in conservation and demand management activities over the period July 1, 2004 to April 30, 2008. Spending on this program was completed in 2008.

In 2006, the OEB approved the Company's 2006 distribution rates providing for a revised rate of return of 9% effective May 1, 2006.

7. Payments in lieu of taxes

The Company's income tax expense for the year ended December 31, 2010 consists of the following:

Temporary differences which give rise to future payments in lieu of tax assets and liabilities are as follows:

?

7. Payments in lieu of taxes (continued)

The impact of differences between the Company's reported payments in lieu of corporate income taxes and the expense that would otherwise result from the application of the combined statutory income tax rate of 31% (2009 - 33%) is as follows:

8. Change in non-cash working capital

The Company acquired property and equipment through non-cash capital contributions of $713,887 (2009 - $42,674).

During the year, the Company received (refunds)/made payments in lieu of taxes in the amount of $51,045 (2009 - $227,407).

9. Related party transactions

The following transactions have been made with the parent company, shareholder of the parent company and a subsidiary of the parent company:

These transactions have taken place in the ordinary course of business and are recorded at the exchange amount.

Included in accounts receivable are $12,436 (2009 - $9,440) owing from related parties and included in accounts payable are $492,378 (2009 - $459,962) owing to related parties. These balances are non-interest bearing with no fixed terms of repayment.

During 2009, the Company migrated its billing system to a SAP platform. The Company has a contractual commitment to pay $3,500 per month for system administration and non-system related support to this related party.

10. Pension agreements

The Company makes contributions to the Ontario Municipal Employees Retirement System ("OMERS"), which is a multi-employer plan, on behalf of its full-time staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by an employee based on the length of services and rate of pay.

Contributions during the year were 6.4% (2009 - 6.5%) for employee earnings below the year's maximum pensionable earnings and 9.7% (2009 - 9.6%) thereafter.

The amount contributed in 2010 is $76,319 (2009 - $63,503) and is included as an expenditure in the Statement of Earnings.

11. 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 should losses be experienced by MEARIE, for the years in which the company and its predecessor company was a member.

To December 31, 2010, the Company has not been made aware of any additional assessments. Participation in MEARIE covers a one year underwriting period which expires January 1, 2011. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next underwriting term.

?

12. Commitments and contingent liabilities

A letter of credit in the amount of $1,464,704 has been issued in favour of the Independent Electricity System Operator ("IESO") as security for the Company's purchase of electricity through the IMO. No amounts were drawn down on the letter of guarantee at year-end.

13. Capital disclosures

The main objectives of the Company when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

As at December 31, 2010, the Company's definition of capital includes shareholder's equity and promissory note. This definition remains unchanged from prior years. As at December 31, 2010, shareholder's equity amounts to $6,220,385 (2009 - $5,891,158) and promissory note amounts to $5,782,746 (2009 - $5,782,746). The Company's capital structure as at December 31, 2010 is 48% debt and 52% equity (2009 - 50% debt and 50% equity). There have been no changes in the Company's approach to capital management during the year.

The Company has customary covenants typically associated with long-term debt. The Company is in compliance with all credit agreement covenants and limitations associated with its long-term debt.

14. Financial instruments and risk management

The Company, through its financial assets and liabilities, has exposure to liquidity and credit risks.

Liquidity risk

The Company's objective is to have sufficient liquidity to meets its liabilities when due. The Company monitors its cash balance and cash flows generated from operations to meet its requirements.

Credit risk

Financial instruments are exposed to credit risk as a result of the counter-party defaulting on its obligations. However, the Company has a large number of diverse customers minimizing concentration of credit risk. The Company requires customers to provide security deposits subject to OEB regulations.

Fair value

The carrying values of cash, accounts receivable, due to/from related parties, bank loan, and accounts payable and accrued liabilities approximate their fair values due to the immediate or short-term maturity of these financial instruments.

Customer and developer deposits have a fair value that approximates carrying value. Interest is paid on deposits on a monthly basis at a market rate, as directed by the Ontario Energy Board.

The promissory note payable to the Town of Grimsby is valued at its face value. It is not practicable within constraints of timeliness or cost to reliably measure its fair value.

15. Comparative figures

Certain of the comparative figures have been reclassified to conform to current year presentation.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

Assets – lines 1000 to 2599

1000	1,602,923	1060	225,369	1062	753,211
1064	12,333	1066	44,115	1120	227,793
1480	1,633,329	1484	85,788	1599	4,584,861
1900	11,307,295	2008	11,307,295	2420	948,627
2421	1,053,766	2589	2,002,393	2599	17,894,549

Liabilities – lines 2600 to 3499

2620	2,554,080	2700	1,600,000	3139	4,154,080
3140	781,782	3260	5,782,746	3320	1,013,324
3450	7,577,852	3499	11,731,932		

Shareholder equity – lines 3500 to 3640

3500	5,782,747	3541	70,721	3600	309,149
3620	6,162,617	3640	17,894,549		

Retained earnings – lines 3660 to 3849

3660	37,690	3680	271,459	3849	309,149

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

Revenue – lines 8000 to 8299

8000	18,747,911	8089	18,747,911	8090	29,695
8230	265,931	8299	19,043,537		

Cost of sales – lines 8300 to 8519

8320	15,370,110	8518	15,370,110	8519	3,377,801

Operating expenses – lines 8520 to 9369

8520	11,749	8670	975,166	8710	459,637
8810	487,848	8960	397,850	9180	25,130
9270	179,325	9284	684,872	9367	3,221,577
9368	18,591,687	9369	451,850		

Farming revenue – lines 9370 to 9659

9659	0

Farming expenses – lines 9660 to 9899

9898	0

Extraordinary items and taxes – lines 9970 to 9999

9970	451,850	9990	82,162	9995	98,229
9999	271,459				

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
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- 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			271,459 A
Add:			
Provision for income taxes – current	101	82,162	
Provision for income taxes – deferred	102	98,229	
Amortization of tangible assets	104	975,166	
Loss on disposal of assets	111	464	
Charitable donations and gifts from Schedule 2	112	700	
Non-deductible meals and entertainment expenses	121	2,099	
Other reserves on lines 270 and 275 from Schedule 13	125	353,898	
Reserves from financial statements – balance at the end of the year	126	788,927	
Subtotal of additions		2,301,645 ▶	2,301,645
Other additions:			
Miscellaneous other additions:			
601 Capital asset additions included in regulatory change	291	1,523,395	
604			
Subtotal of other additions	199	1,523,395 ▶	1,523,395
Total additions	500	3,825,040 ▶	3,825,040
Deduct:			
Capital cost allowance from Schedule 8	403	940,431	
Other reserves on line 280 from Schedule 13	413	781,782	
Reserves from financial statements – balance at the beginning of the year	414	360,398	
Subtotal of deductions		2,082,611 ▶	2,082,611
Other deductions:			
Miscellaneous other deductions:			
700 Reg liability opening balance	390	1,025,025	
701 Reg asset closing balance	391	854,128	
702 Ontario Capital Tax	392	1,534	
704			
Total	394		
Subtotal of other deductions	499	1,880,687 ▶	1,880,687
Total deductions	510	3,963,298 ▶	3,963,298
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			133,201

* For reference purposes only

T2 SCH 1 E (09)

Canada

Attached Schedule with Total

Line 291 – Amount for line 601

Title Line 291 – Amount for line 601

Description	Amount	
Original SM	1,470,004	00
Adjusting journal entry SM	53,391	00
Total	1,523,395	00

Attached Schedule with Total

Line 391 – Amount for line 701

Title Line 391 – Amount for line 701

Description	Amount	
Original Reg Asset	800,737	00
Adjusting journal entry SM	53,391	00
Total	854,128	00

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- For use by corporations to claim any of the following:
  – charitable donations;
  – gifts to Canada, a province, or a territory;
  – gifts of certified cultural property;
  – gifts of certified ecologically sensitive land; or
  – additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  – Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  – If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Imagine Canada	200
Big Brothers & Big Sisters	500
Subtotal	700
Add: Total donations of less than $100 each	
Total donations in current tax year	700

		Federal	Québec	Alberta
Charitable donations at the end of the previous tax year				
Deduct: Charitable donations expired after five tax years*	239			
Charitable donations at the beginning of the tax year	240			
Add:				
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250			
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) 210: 700				
Subtotal (line 250 **plus** line 210)		700	700	700
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		700 A	700	700
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	700	700	700
Charitable donations closing balance	280			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2009-12-31			
2nd prior year	2008-12-31			
3rd prior year	2007-12-31			
4th prior year	2006-12-31			
5th prior year	2005-12-31			
6th prior year*	2004-12-31			
7th prior year	2003-12-31			
8th prior year	2002-12-31			
9th prior year	2001-12-31			
10th prior year	2000-12-31			
11th prior year	1999-12-31			
12th prior year	1998-12-31			
13th prior year	1997-12-31			
14th prior year	1996-12-31			
15th prior year	1995-12-31			
16th prior year	1994-12-31			
17th prior year	1993-12-31			
18th prior year	1992-12-31			
19th prior year	1991-12-31			
20th prior year	1990-12-31			
21st prior year*	1989-12-31			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %			99,901	B
Taxable capital gains arising in respect of gifts of capital property included in Part 1**	225		C	
Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01)	227		D	
The amount of the recapture of capital cost allowance in respect of charitable gifts	230			
Proceeds of disposition, less outlays and expenses**		E		
Capital cost**		F		
Amount E or F, whichever is less	235			
Amount on line 230 or 235, whichever is less			G	
Subtotal (**add** amounts C, D, and G)			H	
Amount H **multiplied** by 25 %				I
Subtotal (amount B **plus** amount I)			99,901	J
Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less)			700	K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		▶
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory*	310		
Subtotal (line 350 **plus** line 310)			
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)		355	
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).		360	
Gifts to Canada, a province, or a territory closing balance		380	

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2009-12-31			
2nd prior year	2008-12-31			
3rd prior year	2007-12-31			
4th prior year	2006-12-31			
5th prior year	2005-12-31			
6th prior year*	2004-12-31			
7th prior year	2003-12-31			
8th prior year	2002-12-31			
9th prior year	2001-12-31			
10th prior year	2000-12-31			
11th prior year	1999-12-31			
12th prior year	1998-12-31			
13th prior year	1997-12-31			
14th prior year	1996-12-31			
15th prior year	1995-12-31			
16th prior year	1994-12-31			
17th prior year	1993-12-31			
18th prior year	1992-12-31			
19th prior year	1991-12-31			
20th prior year	1990-12-31			
21st prior year*	1989-12-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

	Line	Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2009-12-31			
2nd prior year	2008-12-31			
3rd prior year	2007-12-31			
4th prior year	2006-12-31			
5th prior year	2005-12-31			
6th prior year*	2004-12-31			
7th prior year	2003-12-31			
8th prior year	2002-12-31			
9th prior year	2001-12-31			
10th prior year	2000-12-31			
11th prior year	1999-12-31			
12th prior year	1998-12-31			
13th prior year	1997-12-31			
14th prior year	1996-12-31			
15th prior year	1995-12-31			
16th prior year	1994-12-31			
17th prior year	1993-12-31			
18th prior year	1992-12-31			
19th prior year	1991-12-31			
20th prior year	1990-12-31			
21st prior year*	1989-12-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal		Québec		Alberta	
Additional deduction for gifts of medicine at the end of the previous tax year							
Deduct: Additional deduction for gifts of medicine expired after five tax years	639						
Additional deduction for gifts of medicine at the beginning of the tax year	640						
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Additional deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year **610** ______

Québec

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

Alberta

A ______ x (B ______ / C) = Additional deduction for gifts of medicine for the current year ______

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

		Federal	Québec	Alberta
Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2009-12-31			
2nd prior year	2008-12-31			
3rd prior year	2007-12-31			
4th prior year	2006-12-31			
5th prior year	2005-12-31			
6th prior year*	2004-12-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2009-12-31	
2nd prior year	2008-12-31	
3rd prior year	2007-12-31	
4th prior year	2006-12-31	
5th prior year	2005-12-31	
6th prior year*	2004-12-31	
7th prior year	2003-12-31	
8th prior year	2002-12-31	
9th prior year	2001-12-31	
10th prior year	2000-12-31	
11th prior year	1999-12-31	
12th prior year	1998-12-31	
13th prior year	1997-12-31	
14th prior year	1996-12-31	
15th prior year	1995-12-31	
16th prior year	1994-12-31	
17th prior year	1993-12-31	
18th prior year	1992-12-31	
19th prior year	1991-12-31	
20th prior year	1990-12-31	
21st prior year*	1989-12-31	
Total		

* These gifts expired in the current year.

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CORPORATION LOSS CONTINUITY AND APPLICATION

SCHEDULE 4

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- This form is used to determine the continuity and use of available losses; to determine the current-year non-capital loss, farm loss, restricted farm loss, and limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that may be applied in a year; and to request a loss carryback to previous years.
- The corporation can choose whether or not to deduct an available loss from income in a tax year. It can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time **and** no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send it by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes		133,201
Deduct: (increase a loss)		
Net capital losses deducted in the year (enter as a positive amount)		
Taxable dividends deductible under sections 112, 113, or subsection 138(6)		
Amount of Part VI.1 tax deductible		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		
	▶	
Subtotal (if positive, enter "0")		
Deduct: (increase a loss) Section 110.5 and/or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions		
Subtota		
Add: (decrease a loss) Current-year farm loss		
Current-year non-capital loss (if positive, enter "0")		

Continuity of non-capital losses and request for a carryback

	Line		
Non-capital loss at the end of the previous tax year			
Deduct: Non-capital loss expired*	100		
Non-capital losses at the beginning of the tax year	102	▶	
Add: Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105		
Current-year non-capital loss (from calculation above)	110		
		▶	
Subtotal			
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Amount applied against taxable income (enter on line 331 of the T2 return)	130		
Amount applied against taxable dividends subject to Part IV tax	135		
		▶	
Subtotal			
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
		▶	
Non-capital losses – Closing balance	180		

* A non-capital loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004.

Part 1 – Non-capital losses (continued)

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

	Line	Amount	Total
Capital losses at the end of the previous tax year	200	11,325	
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205		11,325
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	250		
Section 80 – Adjustments for forgiven amounts	240		
Subtotal			11,325
Add:			
Current-year capital loss (from the calculation on Schedule 6)	210		
Unused non-capital losses that expired in the tax year*			A
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			B
Enter amount from line A or B, whichever is less	215		
ABILs expired as non-capital loss: line 215 divided by the inclusion rate*** 50.0000 %	220		
Subtotal			11,325

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.

	Line	Amount
Deduct:		
Amount applied against the current-year capital gain (see Note 1)	225	
Subtotal		11,325

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)	Line	Amount carried back (100%)
First previous tax year		951	
Second previous tax year		952	
Third previous tax year		953	

	Line	Amount
Capital losses – Closing balance	280	11,325

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	▶	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	
Deduct:			Subtotal	
Amount applied against listed personal property gains (enter on line 655 of Schedule 6)	530			
Other adjustments	550			
			▶	
			Subtotal	
Deduct – Request to carry back listed personal property loss to:				
First previous tax year to reduce listed personal property gains	961			
Second previous tax year to reduce listed personal property gains	962			
Third previous tax year to reduce listed personal property gains	963			
			▶	
Listed personal property losses – Closing balance			580	

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 – 6)
600	602	604	606	608		620
					Total (enter this amount on line 222 of Schedule 1)	

Limited partnership losses from prior tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662 + 664 + 670 – 675)
660	662	664	670	675	680
			Total (enter this amount on line 335 of the T2 return)		

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- 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);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes other than income tax (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 the instructions for Schedule 5 in 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
132,501		132,501	6,619

Ontario basic income tax (from Schedule 500)	270	17,214		
Deduct: Ontario small business deduction (from schedule 500)	402	10,595		
Subtotal (if negative, enter "0")		6,619	6,619	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)			6,619	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")			6,619	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")			6,619	F6
Deduct:				
Ontario corporate minimum tax credit (from schedule 510)	418	4,716		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			1,903	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282	1,534		
Subtotal		1,534	1,534	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			3,437	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
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			
Other Ontario tax credits				
Subtotal				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		3,437	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** 3,437

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
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

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) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		9,428,006	71,174		0	35,587	9,463,593	4	0	0	378,544	9,120,636
2.	8		307,472	50,849		0	25,425	332,896	20	0	0	66,579	291,742
3.	10		86,415	926		0	463	86,878	30	0	0	26,063	61,278
4.	2		515,166			0		515,166	6	0	0	30,910	484,256
5.	45		4,218			0		4,218	45	0	0	1,898	2,320
6.	47		3,938,473	2,226,166		0	1,113,083	5,051,556	8	0	0	404,124	5,760,515
7.	50	Computer Hardware	2,824			300		2,524	55	0	0	1,388	1,136
8.	52			14,365		0		14,365	100	0	0	14,365	
9.	12			33,120		0	16,560	16,560	100	0	0	16,560	16,560
10.	95	WIP		4,740		0	2,370	2,370	0	0	0		4,740
		Total	14,282,574	2,401,340		300	1,193,488	15,490,126				940,431	15,743,183

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.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		2,401,340		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Rounding adjustment	+	1		
Total additions per books	=	2,401,341	►	2,401,341
Proceeds up to original cost – Schedule 8 regular classes		300		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Loss on disposition of old meters in regulatory asset acct	+	391,841		
Total proceeds per books	=	392,141	– ►	392,141
Depreciation and amortization per accounts – Schedule 1			–	975,166
Loss on disposal of fixed assets per accounts			–	464
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	1,033,570

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		12,508,490
Opening net book value	–	11,474,920
Net change per financial statements	=	1,033,570

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Financial statements – Fixed assets (excluding land) per financial statements – Closing net book value

Title Financial statements – Fixed assets (excluding land) per financial statemen

Description	Amount	
Fixed assets per F/S	11,307,295	00
Less: land	-111,556	00
Add: smart meters	1,312,751	00
Total	12,508,490	00

Attached Schedule with Total

Financial statements – Fixed assets (excluding land) per financial statements – Opening net book value

Title Financial statements – Fixed assets (excluding land) per financial statemen

Description	Amount	
Opening NBV	11,405,282	00
Less: land	-111,556	00
Add: smart meters	181,194	00
Total	11,474,920	00

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Niagara Power Incorporated		86880 5920 RC0001	1					
2.	Grimsby Hydro Incorporated		86880 1929 RC0001	3					
3.	Grimsby Energy Incorporated		86880 1721 RC0001	3					
4.	Town of Grimsby		10698 4636 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 13

CONTINUITY OF RESERVES

Name of corporation	Business Number	Tax year end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- References to parts, sections, subsections, paragraphs, and subparagraphs are from the federal *Income Tax Act*.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on amalgamation or wind-up of subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The total capital gains reserve at the beginning of the taxation year plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary should be entered on line 880, and the total capital gains reserve at the end of the taxation year, should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

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 $
Reserve for doubtful debts		110	115			120
Reserve for undelivered goods and services not rendered	X	130 353,898	135	781,782	353,898	140 781,782
Reserve for prepaid rent		150	155			160
Reserve for December 31, 1995 income		170	175			180
Reserve for refundable containers		190	195			200
Reserve for unpaid amounts		210	215			220
Other tax reserves		230	235			240
Totals		270 353,898	275	781,782	353,898	280 781,782

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 plus the amount from line 275 should be entered on line 125 of Schedule 1 as an addition.
The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

T2 SCH 13 E (99)

Canada

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	General Allowance for Doubtful	6,500		7,145	6,500	7,145
	Reserves from Part 2 of Schedule 13	353,898		781,782	353,898	781,782
	Totals	360,398		788,927	360,398	788,927

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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Niagara Power Inc.	231 Roberts Rd Grimsby ON CA L3M 5N2			11,000		

T2 SCH 14 (99)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $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 2010

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 **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	Grimsby Power Incorporated	86487 4839 RC0001	1	500,000	100.0000	500,000
2	Niagara Power Incorporated	86880 5920 RC0001	1	500,000		
3	Grimsby Hydro Incorporated	86880 1929 RC0001	1	500,000		
4	Grimsby Energy Incorporated	86880 1721 RC0001	1	500,000		
5	Town of Grimsby	10698 4636 RC0001	1	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.

T2 SCH 23 (09) Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 33

TAXABLE CAPITAL EMPLOYED IN CANADA – LARGE CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- 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:

Reserves that have not been deducted in computing income for the year under Part I	101	166,342		
Capital stock (or members' contributions if incorporated without share capital)	103	5,782,747		
Retained earnings	104	309,149		
Contributed surplus	105	70,721		
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	8,164,528		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
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		14,493,487 ▶	14,493,487	A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121	1,053,766		
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		1,053,766 ▶	1,053,766	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		13,439,721	

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	152,320
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	152,320

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 190)		13,439,721	C
Deduct: Investment allowance for the year (line 490)		152,320	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	13,287,401	

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) 13,287,401 x $\frac{\text{Taxable income earned in Canada} \quad \textbf{610} \quad 132,501}{\text{Taxable income} \quad 132,501}$ = **Taxable capital employed in Canada** **690** 13,287,401

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business 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

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in computing income for the year under Part I

Title Part 1 – Reserves that have not been deducted in computing income for th

Description	Amount	
General allowance for doubtful accounts	7,145	00
Net Regulatory Liability (1,013,324 - 854,127)	159,197	00
Total	166,342	00

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Part 2 – A loan or advance to another corporation (other than a financial ir

Description	Amount	
Deposit on long-term asset	94,500	00
Eligible prepaid expenses	57,820	00
Total	152,320	00

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Amount	
Customer Deposits	290,304	00
Developer Deposits	491,478	00
Promissory Note	5,782,746	00
Bank Loan	1,600,000	00
Total	8,164,528	00

Attached Schedule with Total

Part 1 – Deferred tax debit balance at the end of the year

Title Part 1 – Deferred tax debit balance at the end of the year

Description	Amount
Future Taxes (40,442 + 1,013,324)	1,053,766 00
Total	1,053,766 00

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	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	Niagara Power Incorporated	86880 5920 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

On: 2010-12-31

- 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 I*ncome 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? . . . . . [ ] 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	1,908,974	A
Taxable income for the year (DICs enter "0") *	110	132,501	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	132,501			
After-tax income (line 150 x general rate factor for the tax year ** 0.69)			190	91,426	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)				2,000,400	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	2,000,400	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560		
GRIP at the end of the tax year (line 490 **minus** line 560) Enter this amount on line 160 of Schedule 55.			590	2,000,400	

* 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			270,907	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	270,907	L1			
Aggregate investment income (line 440 of the T2 return)		M1			
Subtotal (**add** lines K1, L1, and M1)	270,907	►	270,907	N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")				►	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) . . . . **500** ______

Second previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 755,476 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 51,804 L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Subtotal (**add** lines K2, L2, and M2) 51,804 ► 51,804 N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 703,672 ► 703,672 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) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year 351,360 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 104,071 L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) 104,071 ▶ 104,071 N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 247,289 ▶ 247,289 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**

Taxable income after specified future tax consequences . . . . ______ 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 . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ▶ ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ 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** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ______ 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

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or 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 5 – 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	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 365	. . . . =		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	365 / 365	. . . . =	0.6900	RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 365	. . . . =		SS
0.72	x	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) . . . . 0.6900 UU

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- References to subsections and paragraphs are from the federal *Income Tax Act*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

	Days		Rate		Result	
Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	14.00 %	=	6.94247 %	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	12.00 %	=	6.04932 %	A2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	11.50 %	=	%	A3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 12.99179 ► 12.99179 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 132,501 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . . . 17,214 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)		133,201	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)		132,501	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000 x 500,000 / 500,000 (line 4 on page 4 of the T2 return) =	500,000	3
Enter the least of amounts 1, 2, and 3		132,501	D
Ontario domestic factor: Ontario taxable income * / taxable income earned in all provinces and territories **	132,501.00 / 132,501 =	1.00000	E
Ontario small business income (amount D **multiplied** by amount E)		132,501	F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x	8.50 %	=	4.21507 %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	184 / 365	x	7.50 %	=	3.78082 %	G2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	/ 365	x	7.00 %	=	%	G3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	/ 365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	/ 365	x	5.50 %	=	%	G5
OSBD rate for the year (total of rates G1 to G5)					7.99589 %	G6

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6) . . . 10,595 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *	132,501	I		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	1,325	J		
Aggregate adjusted taxable income (amount I **plus** amount J)	133,826	▶	133,826	K
Deduct:				
Ontario business limit			500,000	
Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P)				L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year: 181 / 365 x 4.25 % = 2.10753 % M

Amount L x % on line M = ... N

Amount N ______ x Ontario small business income (amount F from Part 3) / 500,000: 132,501 / 500,000 = ... O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) .... P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Amount D from Part 3 .... 132,501 Q

Surtax payable (amount P from Part 4) / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 7.99589 %: ______ / 0.07996 = ______ R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") .... 132,501 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		T	
Deduct:			
Ontario adjusted small business income (amount S from Part 5)		U	
Subtotal (amount T **minus** amount U) (if negative, enter "0")		V	
OSBD rate for the year (rate G6 from Part 3)	7.99589 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 501

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations* 100	Business number of associated corporations** 200	Tax year-end 300	Adjusted taxable income *** (if loss, enter "0") 400
1	Niagara Power Incorporated	86880 5920 RC0001	2010-12-31	
2	Grimsby Hydro Incorporated	86880 1929 RC0001	2010-12-31	1,325
3	Grimsby Energy Incorporated	86880 1721 RC0001	2010-12-31	
4	Town of Grimsby	10698 4636 RC0001	2010-12-31	
			Total 500	1,325

Enter the total adjusted taxable income from line 500 on line J in Part 4 of Schedule 500, *Ontario Corporation Tax Calculation.*

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

***** Rules for adjusted taxable income:**

- If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365, and **divide** by the total number of days in all of those tax years.

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 5 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- 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	17,894,549
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	2,343,690
Total assets (total of lines 112 to 116)		20,238,239
Total revenue of the corporation for the tax year **	142	19,043,537
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	1,071,729
Total revenue (total of lines 142 to 146)		20,115,266

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 Ontario Act 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 Ontario Act.

** **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 Ontario Act 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 Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	271,459
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	82,162		
Provision for deferred income taxes (debits)/cost of future income taxes	222	98,229		
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), 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		180,391 ►		180,391 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		►		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	451,850

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, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property;
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These 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.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– 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.

– 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 Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act 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 Ontario Act 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 Ontario Act 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		
Deduct:			
CMT loss available (amount R from Part 7)			
Minus: Adjustment for an acquisition of control *	518		
Adjusted CMT loss available	▶		C
Net income subject to CMT calculation (if negative, enter "0")	520		

Amount from line 520		x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	181 / 365	x 4 % =	1
Amount from line 520		x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	184 / 365	x 2.7 % =	2
			Subtotal (amount 1 **plus** amount 2)			3

Gross CMT: amount on line 3 above x OAF **	540		
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")			D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		6,619	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** 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 *		4,716	G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)		4,716	▶ 620	4,716	
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)				4,716	H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)				4,716	I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670		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)				4,716	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		6,619	1		
For a corporation that is not a life insurance corporation:					
CMT after foreign tax credit deduction (amount D from Part 3)			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:			6		
Subtotal (if negative, enter "0")		6,619	▶	6,619	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		6,619			
Deduct:					
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)					
Subtotal (if negative, enter "0")		6,619	▶	6,619	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				4,716	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 Ontario Act.

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 22, 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 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Niagara Power Incorporated	86880 5920 RC0001	0	0
2	Grimsby Hydro Incorporated	86880 1929 RC0001	1,906,645	263,937
3	Grimsby Energy Incorporated	86880 1721 RC0001	437,045	807,792
4	Town of Grimsby	10698 4636 RC0001	0	0
		Total	450 2,343,690	550 1,071,729

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** 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 associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated 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.

T2 SCH 511

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- 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).
- The Ontario capital tax is eliminated effective July 1, 2010. You do not have to complete this schedule if the corporation's tax year begins after June 30, 2010. For businesses mainly engaged in qualifying manufacturing and resource activities in Ontario, the capital tax is eliminated effective January 1, 2007.
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations* (renamed *Taxable Capital Employed in Canada – Large Corporations* for 2010 and later tax years). 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

	Line	Amount		Total	
Amount A from Part 1 of Schedule 33	100	14,493,487			
Add:					
Accumulated other comprehensive income at the end of the year	105				
Subtotal		14,493,487	▶	14,493,487	A
Deduct:					
Amount B from Part 1 of Schedule 33	110	1,053,766			
Amount on line 490 from Part 2 of Schedule 33	115	152,320			
Subtotal		1,206,086	▶	1,206,086	B
Taxable capital (amount A **minus** amount B) (if negative, enter "0")	120			13,287,401	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? **190** 1 Yes [X] 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.

$$\frac{\text{Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33)}\ \textbf{200}\ \_\_\_}{\text{Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *}\ \textbf{210}\ \_\_\_} \times 15{,}000{,}000\ \$ = \textbf{Capital deduction}\ \textbf{220}\ \_\_\_$$

* 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).

$$\frac{\text{Allocation of net deduction (from line 600 for the filing corporation from Schedule 516)}\ \textbf{300}\ 11{,}224{,}500}{\text{Ontario allocation factor (OAF) (amount I in Part 3)}\ 1.00000} = \textbf{Capital deduction}\ \textbf{305}\ 11{,}224{,}500$$

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 33), whichever applies **320** 13,287,401

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) . . . . . 11,224,500 B

Net amount (line 320 **minus** amount B) (if negative, enter "0") . . . . . 2,062,901 C

Note: For days in the tax year after June 30, 2010, the Ontario capital tax rate is 0%.

Amount C 2,062,901 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) (/ 365) x 0.00225 = D

Amount C 2,062,901 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) (181 / 365) x 0.00150 = 1,534 E

Subtotal (amount D **plus** amount E) 1,534 F

Amount F 1,534 x OAF (amount on line I) 1.00000 = ... 1,534 G

Amount G 1,534 x (Number of days in the tax year * / 365) (365 / 365) = ... 1,534 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** 1,534

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 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** x 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% (% / 30.000 %) x 1,534 Amount H from Part 3 =

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 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	Grimsby Power Incorporated	86487 4839 RC0001	100.000	16,662,746	8,165,620	11,224,500
2.	Niagara Power Incorporated	86880 5920 RC0001	100.000	12,319,036	6,036,974	2,805,000
3.	Grimsby Hydro Incorporated	86880 1929 RC0001	100.000	1,244,807	610,021	630,000
4.	Grimsby Energy Incorporated	86880 1721 RC0001	100.000	382,377	187,385	340,500
5.	Town of Grimsby	10698 4636 RC0001				

Total assets of associated group (total of amounts in column D) 700 30,608,966

Total net deduction (total of amounts in column E) 800 15,000,000

Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) 900 15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

T2 SCH 516

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Grimsby Power Incorporated	86487 4839 RC0001	2010-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *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. Visit **www.ServiceOntario.ca** for more information.
- 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)
Grimsby Power Incorporated

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	2000-04-20	1414228

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
231	Roberts Road	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Grimsby	ON	CA	L3M 5N2

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 for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? 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**.

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 Curtiss (Last name) **451** Doug (First name)

454 ______________________, (Middle name(s))

460 1 Please enter one of the following numbers in this box for the above-named person: **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/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . Grimsby Power Incorporated

Taxation Year . . . . 2010-01-01 to 2010-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 4

Type of corporation . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* . . . . -80,713

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	133,201
Taxable income	132,501
Donations	700
Calculation of income from an active business carried on in Canada	133,201
Dividends paid	
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	1,908,974
Balance of the general rate income pool at the end of the year	2,000,400
Part I tax (base amount)	50,350

Credits against part I tax		**Summary of tax**		**Refunds/credits**	
Small business deduction		Part I	23,850	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	108,000
Investment tax credits		Other*		Surtax credit	
Abatement/Other*	26,500	Provincial or territorial tax	3,437	Other*	
				Balance due/refund (–)	-80,713

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Investment tax credits	
Non-capital losses	
Capital losses	
Farm losses	
Restricted farm losses	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	

Carryforward balances

RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	

Summary of federal carryforward/carryback information (continued)

Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Gifts of medicine	
Investment tax credits	
Non-capital losses that can be carried forward over 7 years	
Non-capital losses that can be carried forward over 10 years	
Non-capital losses that can be carried forward over 20 years	
Capital losses/L.P.P.	11,325
Farm losses that can be carried forward over 10 years	
Farm losses that can be carried forward over 20 years	
Restricted farm losses that can be carried forward over 10 years	
Restricted farm losses that can be carried forward over 20 years	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	
Capital dividend amount	
Part I tax credit (Schedule 42)	
Cumulative eligible capital	
Capital gains reserves	
Financial statement reserve	788,927
Other reserves	781,782
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	133,201		
Taxable income	132,501		
% Allocation	100.00		
Attributed taxable income	132,501		
Surtax		N/A	N/A
Tax payable before deduction*	17,214		
Deductions and credits	15,311		
Net tax payable	1,903		
Attributed taxable capital	13,287,401		N/A
Capital tax payable**	1,534		N/A
Total tax payable***	3,437		
Instalments and refundable credits			
Balance due/Refund (-)	3,437		

* For Québec, this includes special taxes and logging operations.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial information – provincial income tax payable (continued)

	British Columbia	Saskatchewan	Manitoba
% Allocation			
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable**			
Instalments and refundable credits			
Balance due/Refund (-)			

* For British Columbia, this includes the Logging Tax Payable.

** For Manitoba, this includes the Outstanding Balance Excluding Instalments.

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				

* Only applies in the case of bank, a loan corporation or a trust corporation.

	Yukon	Northwest Territories	Nunavut
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			

Summary of provincial carryforward amounts

	Québec	Alberta
Non-capital losses that can be carried forward over 7 years		
Non-capital losses that can be carried forward over 10 years		
Non-capital losses that can be carried forward over 20 years		
Net capital losses/Listed personal property losses		
Farm losses that can be carried forward over 10 years		
Farm losses that can be carried forward over 20 years		
Restricted farm losses that can be carried forward over 10 years		
Restricted farm losses that can be carried forward over 20 years		
Donations		
Capital gains reserves		
Financial statement reserves		
Other reserves		
Eligible capital		

Other carryforward amounts

Ontario	
Transitional tax credit – Schedule 506	
Ontario research and development tax credit – Schedule 508	
Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510	
Corporate minimum tax credit that can be carried forward over 10 years – Schedule 510	
Corporate minimum tax loss that can be carried forward over 20 years – Schedule 510	
Corporate minimum tax loss that can be carried forward over 10 years – Schedule 510	
Ontario political contributions tax credit that can be carried forward over 20 years – Schedule 525	
Québec	
R&D expenditures not deducted at the end of the year – RD-222	
Tax credit for fees and dues paid to a research consortium – RD-1029.8.9.03	
Foreign non-business income tax credits – CO-17S.39	
Non-refundable tax credit for resources – 1029.8.36.EM	
Investment Tax Credit – CO-1029.8.36.IN	
Development work expenses – FM220.3	
Excess development work expenses – FM220.3	
Balance of patronage dividends – CO-786	
Alberta	
Unclaimed SR&ED expenditure pool deduction balance – A16	
British Columbia	
Scientific research and experimental development – Schedule 425	
Manufacturing and processing – Schedule 426	
Manitoba	
Research and development – Schedule 380	
Manufacturing investment – Schedule 381	
Co-op education and apprenticeship – Schedule 384	
Odour control – Schedule 385	
Community enterprise investment – Schedule 387	
Saskatchewan	
Royalty tax rebate – Schedule 400	
Manufacturing and processing investment – Schedule 402	
Research and development – Schedule 403	

Summary of provincial carryforward amounts (continued)

Newfoundland and Labrador

Direct equity tax – Schedule 303 . . . .

Prince Edward Island

Investment – Schedule 321 . . . .

Nova Scotia

Energy efficiency tax credit – Schedule 342 . . . .

Manufacturing and processing investment – Schedule 344 . . . .

New Brunswick

Research and development – Schedule 360 . . . .

Nunavut

Investment – Schedule 480 . . . .

Five-Year Comparative Summary

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Federal information (T2)					
Taxation year end	2010-12-31	2009-12-31	2008-12-31	2007-12-31	2006-12-31
Net income	133,201	272,657	755,476		
Taxable income	132,501	270,907	755,476		
Active business income	133,201	272,657	755,476		
Dividends paid		1,200,000	2,100,000		
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	1,908,974	1,908,974	1,430,477		
GRIP – end of the year	2,000,400	1,908,974	1,908,974		
Donations	700	1,750			
Balance due/refund (-)	-80,713	-177,991			

Federal taxes

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Part I before surtax	23,850	29,800	142,914		
Surtax					
Part I.3					
Part IV					
Part I & Surtax	23,850	29,800	142,914		
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Small business deduction		46,054	8,807		
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit					
Abatement/other*	26,500	27,091	135,360		

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
ITC refund					
Dividend refund			6,680		
Instalments	108,000	227,407	136,234		
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2010-12-31	2009-12-31	2008-12-31	2007-12-31	2006-12-31
Net income	133,201		755,476		
Taxable income	132,501		755,476		
% Allocation	100.00	100.00	100.00		
Attributed taxable income	132,501		755,476		
Surtax			21,226		
Income tax payable before deduction	17,214	37,927	105,767		
Income tax deductions /credits	15,311	23,027	43,429		
Net income tax payable	1,903	14,900	83,564		
Taxable capital	13,287,401	10,914,443	11,207,377		
Capital tax payable	1,534				
Total tax payable*	3,437	19,616	83,564		
Instalments and refundable credits			93,966		
Balance due/refund**	3,437	19,616	-10,402		

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Appendix 4.2 Grimsby Power Inc. – Grimsby Power Inc.'s Purchasing Policy – Document Number 2.01

Purpose

It is the policy of Grimsby Power Incorporated to optimize the purchases to ensure receiving the best quality goods at the lowest price.

Details

This policy shall cover the approval process, the spending limits, and the tender requirements for purchases made by Grimsby Power Incorporated.

For the purposes of this policy:

- "The Corporation" means Grimsby Power Incorporated
- "The Board" means the Board of Directors of Grimsby Power Incorporated
- "The Shareholder" means Niagara Power Incorporated
- "The Chief Executive Officer" means the Chief Executive Officer of Grimsby Power or in his absence an approved designate appointed by the Shareholder.
- "The Chair" means the chair of GPI
- "Director" means the Director of Finance or the Director of Human Resources.
- "Supervisor" means those with direct supervisory capacity and rolls within their respective departments.

Business Process

Purchase Orders

The person requesting equipment, material or service is required to obtain at least two quotations. Three is preferable.

The PO must include all pertinent information such as an hourly rate and estimate number of working hours or unit price, whichever is applicable.

They will submit the request to their immediate supervisor for approval, if applicable.

The Supervisor will submit the quotations with a request that the Director of Finance verify the budgeted costs and all other financial aspects are correct. Then submit the purchase order to the Chief Executive Officer for approval.

The person will be advised when the purchase order is approved and issued.

Definition of Purchases

Large Purchases

For the purpose of this policy, items of $20,000 or greater per piece per item.

Small Purchases

Small Purchases are those less than $20,000.00

Minor Purchases

Minor Purchases are purchases for emergency and minor building maintenance and operational expense purchases.

Notwithstanding the Definition of Purchases the Chief Executive Officer in consultation with the Chair of the Board may authorize purchases in the event of an emergency provided that such purchase is reported to the Board at the next scheduled board meeting.

Best Price

The Corporation will purchase the lowest price equipment; material or service provided that our specifications, standards and delivery requirements are all met.

Tender Requirements

The Corporation shall issue calls for tender for large item purchases.
The Corporation shall ask for at least three tenders.
Tenders may not be issued if fewer that two tenders are received.
Tenders may not be issued without approval of the Board.

The Board, at its discretion may wave the requirement for tendering under financial or other interests of the corporation.

Approvals

The Board authorizes the Supervisor to approve requisitions.

The Board authorizes the Chief Executive Officer and Director to approve Purchase Orders.

Note: The Director of Finance may approve Purchase Orders in the absence of the Chief Executive Officer or Chair. However, they must ensure that they abide by the policy and determine the prudence of the purchase.

Upon receipt of approval, a purchase order must be issued and approved by the Director of Finance, or in the absence of the Director of Finance, the Chief Executive Officer.

The Board authorizes the Chief Executive Officer and a Director to sign cheques, pay by telephone or electronically for goods and services up to a maximum of $20,000.00 per piece per item provided that the said goods and services have received approval to purchase as outlined below.

All purchases greater than $20,000.00 must be paid via cheque.

Supervisors may approve requisitions up to $500.00 exclusive of taxes as a small purchase.

Arrangements have been made with local suppliers for minor emergency and building maintenance and operational expense purchases. Employees are required to code the receipt to the appropriate job and GL, and then submit the vendor receipt to their immediate supervisor for information and approval. Supervisors will then provide the approved expense to the Accounts Payable Clerk to match up with the monthly statement from the vendor.

Exceptions

The Board of Directors of Grimsby Power Incorporated authorizes the Chief Executive Officer and a Director to pay power invoices, taxes including Goods and Services Tax (GST) or any other regulated/mandatory imposed invoices without Board approval. The Chief Executive Officer and a Director may authorize others to electronically pay items they have approved.

Notwithstanding the above no employee of Grimsby Power has the authorization to bind the Corporation without prior approval from the Board of Directors or under specific circumstances the Chief Executive Officer.

Appendix 4.3 Grimsby Power Inc. – IFRS Conversion Project – Componentization and Depreciation

GRIMSBY POWER INCORPORATED
IFRS CONVERSION PROJECT

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment

Topic: Componentization and Depreciation

Objective:

To document the accounting policy on componentization and depreciation of property, plant and equipment.

Background:

Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

An entity should allocate the amount initially recognized in respect of an item of PPE to its significant parts to be depreciated separately.

A significant part of an item of PP&E may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

Depreciation is to be computed on computed on a systematic basis over the estimated useful life of the item of PP&E. the depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with **IAS 8** *Accounting Policies, Changes in Accounting Estimates and Errors.*

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with **IFRS 5** and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted under IFRS. Each significant component and the estimated useful lives, for purposes of computing depreciation expense under IFRS, will be set out in Table 1 as attached.

Overhead system

Four components identified – poles, primary conductor and devices, transformers and secondary conductor

The primary reason for the decision is the fact that the company is in the process of upgrading the system. When the pole is replaced, everything on the pole is replaced. The overhead system life is limited to the life of the pole which has been determined to be 60 years. Primary conductor and devices have been identified as a component since post upgrade these asset will have a life different than that of the pole since the company does sometimes transfer used conductor to a new pole. The poles, primary conductor and devices and secondary conductor has been determined to have the same useful life because of the upgrade that is in process. Experience has shown that the poles being removed today have an average age of 50 to 60 years. Kinectrics minimum useful life of 35 years was considered to be unreasonable because the company has poles in the system that are 30 years old and still providing service. Environmental factors are not higher than moderate identified by Kinectrics for the typical life of a pole. The company's poles are not significantly loaded so there is no undue stress on the pole. This has the impact of extending the life beyond that identified by Kinectrics for the typical useful life. Kinectrics identified the typical life as 45 years and the maximum life as 75 years. The company's practices suggest that the life of the pole is greater than typical but greater incidence of extreme weather has put greater stress on the poles. This would indicate that the maximum useful life is not appropriate either. Maintenance practices indicate a low level of pole failure which also indicates a higher useful life than typical. So a useful life of 60 years was chosen for the overhead system since it is between the typical life and the maximum life identified by Kinectrics and is supported by company experience.

Transformers

Experience has shown that transformers do not last as long as the pole. Older transformers are larger units which have greater electrical clearance and more oil and space between components which lessen the impact of lightening strikes. Transformers have not been lasting 60 years (maximum life identified by Kinectrics). The older transformers could handle more stress. Transformer failures have been increasing due to the impact of weather. Environmental factors are higher than the moderate identified by Kinectrics for the typical useful life. Decided to use a life of 35 years which is higher than the minimum and lower than the typical.

Underground System

Four components were identified – primary cable, services cable, transformers and ducts. The company does not have any experience with the end of life of its underground assets. The underground system has been in place for between 20 and 30 years. Separate components were identified since the company would not necessarily replace the devices and transformers when the cable is replaced. Primary and services cable would not necessarily be replaced at the same time. Most of the cable in the system is direct buried TR/XLPE. The company has taken steps to maximize the life of its underground cable. The company has stringent installation instructions for its contractors. No splicing of the cable is allowed. The company has injected its cable with silicon to extend the life of the cable. This is expected to increase the life by 10 -20 years. No failures in the underground system have been experienced. Kinectrics identified the typical useful life as 30 years and maximum useful life as 35 years. The company's practices should allow it to get the maximum useful life out of its primary cable.

Switchgear is a fraction of the installed cost of the primary cable and therefore is not a significant component. The useful life of the switchgear is similar to the primary cable. Failure has occurred at 28 years of age. The company has two types of switchgear – PVI19 totally enclosed and PMH9. The PVI9s have had no failures and would have a higher useful life. The PMH9 have failed at 28 years of age. PVI9 is lasting longer than 30 years and PMH9 is lasting less than 30 years. So the life on average is similar to the primary cable.

Similar reasoning is used for the secondary cable. Bus connections increase the risk of failure for secondary cable. The company has very few bus connections, using direct connections instead. For this reason, the company expects to get the maximum useful life of 40 years from its secondary cable.

Experience has shown underground transformers are failing at between 28 and 32 years of age. Environmental conditions are impacting the life of the transformers. The primary cause of deterioration is rust. The company has had to increase its replacement of transformers in 2010 as a result of inspection results. The company's experience shows that failure increase at approximately 30 years. The useful life is set at 30 years.

The company has no concrete encased duct bank and has not experienced any failures with its ducts. There is no cable in the duct. The ducts are to be used to pull new cable through when the old cable needs to be replaced. This has the impact of reducing the stress on the duct. There is an increased risk of damage to the duct when cable is pulled through The main impact is the weight of the soil on the duct. Installation technique is considered to be another primary factor influencing useful life of the ducts. The company does not have rigorous inspection during the installation of its ducts. Kinectrics useful life ranges from 30 to 85 years. The company's practices increase the useful life beyond the typical but are less than the maximum. A useful life of 70 years was chosen based upon two life cycles of primary cable (35 years each cycle).

Minor assets

The existing components for the minor assets is considered to be appropriate with the exception of meter assets since the minor assets are not significant in relation to the distribution system assets. The components are office equipment, transportation equipment, administrative buildings, computer hardware and software, stores equipment, tools, shop and garage equipment, measurement and testing equipment, communications equipment, residential meters, GS<50 meters, GS>50 meters, Microfit meters, CTs and PTs, smart meter hardware, smart meter software and smart meters.

The residential meters are all stranded meters. The useful life was determined to be the recovery period determined by the OEB. GS<50 and GS>50 are electronic meters with technological obsolescence limiting useful life. Technology is updated before the meter is at the end of its useful life. Due to technological obsolescence, these meters have useful life of 15 years.

There is no experience in the industry with smart meters. Technological obsolescence is the major factor impacting useful life. For this reason, the mid-point (10 years) in the Kinectrics life range was selected as the useful life.

Wholesale meters are basically interval meters and must be removed for recertification every 6 or 10 years. These meters are no different than the industrial/commercial meters. The useful life is set at 15 years.

Microfit meters have the same technology as smart meters. The life is determined to be 10 years.

Wholesale CTs and PTs are impacted by weather. Almost all of the CTs & PTs are retail and there are only 4 wholesale metering points in the system. The non-wholesale CTs & PTs have a 40 year useful life compared to the wholesale CTs & PTs which have a life of approximately 25 years. The difference is due to weather and voltage. The average of 35 years has been chosen as the useful life.

Smart meter software is no different than other types of software. Technological obsolescence is the limiting life factor. The life is set at 5 years.

Smart meter hardware includes handheld devices which receive more wear and tear. The life is determined to be 5 years.

Communication equipment consists of TGB and FMPs. This equipment is technology based and is wireless technology. Technological obsolescence limits the life of these assets. Same life as for software is to be sued – 5 years.

Office equipment is not a significant asset. The life is determined to be 10 years.

The majority of the company's vehicles are large trucks which are used for 20 years. There are some smaller vehicles that have a shorter life. For this reason a life of 15 years is used. The smaller vehicles are not significant to componentize.

The only building owned by the company is the administrative building. Kinectrics life range is 50 to 75 years. Selected 50 years as the useful life.

The station buildings are all older than 25 years and so are fully depreciated. The company does not intend to build any new stations buildings. No useful life is necessary.

Computer hardware and software is limited by technological obsolescence. The life is determined to be 5 years.

Useful lives for stores, tools, shop, garage equipment and measurement & testing equipment are determined based upon experience for average useful life(10, 10 and 5 years respectively).

Conclusion:

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2011. The net book value as deemed cost exemption (available to rate regulated entities) will be applied so that the opening values at January 1, 2011 do not need to be restated and therefore, componentization does not need to be applied retroactively.

Table 1: GPI – PP&E Components and Estimated Useful Lives

Component	Previous Component	Proposed Useful Life	Existing Useful Life
Land	Land	N/A	N/A
Buildings	Buildings – Robert Rd	50	50
Buildings – Paving/Fencing	Buildings – Robert Rd	40	40
Buildings – Other Fixtures	Buildings – Robert Rd & Other	25	25
Overhead poles	Overhead Poles	60	25
Overhead line switches and conductors	Overhead Conductors & Devices	60	25
Overhead secondary cables	Overhead Services	60	25
Underground primary cables and switchgears	Underground Conductors & Devices	35	25
Underground secondary cables	Underground Services	40	25
Underground ducts	Underground Conduit	70	25
Underground concrete encased duct banks	Underground Conduit	70	25
Overhead Transformers	Overhead Transformers	35	25
Underground Transformers	Underground Transformers	30	25
Residential Meters (Stranded Meters)	Meters – Single & 3 Phase	25	25
Industrial/Commercial Energy Meters	Interval Meters – 1 Phase, 3 Phase & Meters YE Adj	15	25
Wholesale Energy Meters	Meters	15	25
Other meters, PTs & CTs	Meters	35	25
Office Furniture and Equipment	Office Furniture and Equipment	10	10
Computer Equipment Hardware	Computer Equipment Hardware	5	3
Computer Software	Computer Software	5	5
Vehicles	Transportation Equipment	15	15
Tools, Shop, Garage Equipment	Tools, Shop, Garage Equipment	10	10
Measurement & Testing Equipment	Measurement & Testing Equipment	5	5
Wireless Communication	Communication Equipment	5	10

Appendix 4.4 Grimsby Power Inc. Green Energy Act Plan

GRIMSBY POWER INC.

Basic Green Energy Act Plan

Grimsby Power Inc.
Basic Green Energy Act Plan
March 2011

Table of Contents

GRIMSBY POWER INC.

Basic Green Energy Act Plan

1 Summary Information

1.1 Introduction

Grimsby Power Inc. (GPI) is a local distribution company (LDC) serving more than 10,000 customers in the Town of Grimsby. In accordance with the Ontario Energy Board's (OEB) Filing Requirements (EB-2009-0397) GPI has prepared a Basic Green Energy Act (GEA) Plan. The GEA Plan is based on current information and represents GPI's best efforts to enable the connection of renewable generation facilities and to create a Smart Grid development strategy.

1.2 Current Situation

GPI distributes power from two transformer stations:

- Beamsville TS – Owned by Hydro One (HO)
- Niagara West Transformer Station (NWTS) – Owned by Niagara West Transformation Corporation (NWTC)

GPI uses two distribution stations to further transform its distribution voltage to the 8.13kV level. The two stations are as follows:

- Kerman DS
- Baker DS

At this point in time GPI has been informally advised by Hydro One and Niagara West Transformation Corporation that both transformer stations respectively may have short circuit limitations which may affect future MicroFIT and FIT connections. However, GPI has not received formal written notification to stop connecting these projects.

1.3 Current Renewable Generation

Project applications submitted to the OPA include the following:

- 27 Residential MicroFIT Solar PV
- 2 Commercial FIT
    - 1 Solar PV
    - 1 Biogas

Of the above projects the following have been approved and connected:

- 6 Residential MicroFIT Solar PV
- 0 Commercial FIT

The distribution system has been virtually unaffected by the six projects connected thus far. In 2010 the rate of connections was slow likely due to the economy and availability of contractors to install these types of installations. The number of applications in 2011 has continued on a steady pace and it is likely that the rate of connections will increase. However, there is a large amount of uncertainty about the actual connection rate. GPI's forecast of connections is based on GPI's experience to date and requests for information from prospective generators. This GEA Plan includes information on how the anticipated renewable connections will impact GPI's distribution system.

1.4 Current Information on Smart Grid Projects

The term "Smart Grid" has been used to describe a number of initiatives within the electrical distribution, transmission, and generation environments. For distribution utilities like GPI Smart Grid projects are likely to centre on the following concepts:

- Optimization of the Distribution System
- Creating Self Healing Distribution Networks – Network Automation
- Distribution Intelligence – Monitoring the Network

- Two Way Communication Interfaces with the Customer
- Demand Control at the Customers Load – Home Area Networks

Smart Grid pilot projects, of all types, are being tested around the globe in various jurisdictions and are very much in a preliminary discovery phase. Significant impediments to the implementation of Smart Grid would include:

- Consumer Concerns Over Privacy
- Social Concerns Over the Use of Distribution System Information (including customer information)
- Limited ability of utilities to transform their networks in a short period of time
- Concerns over giving governments control over power using activities
- The cost benefit of projects

Given the uncertain nature of Smart Grid development GPI's strategy will be to adopt a very conservative approach to the implementation of Smart Grid projects.

1.5 Summary of Forecasted Expenditures

GPI has not forecasted any internal expenditures with respect to this GEA Plan. All internal expenditures will be retained under the current rate structure. GPI has forecasted $25,000 per year starting in 2012 for third party professional services with respect to this GEA Plan.

2 Detailed Assessment

2.1 Existing Conditions

As noted above, GPI distributes power from transformer stations owned by Hydro One and the Niagara West Transformation Corporation. Potential constraints on renewable connections from a TS perspective are:

- Thermal Capacity
- Short Circuit Capacity

From a distribution system perspective potential constraints on renewable connections are:

- Distribution Feeder or Line Capacity
- Thermal Capacity

GPI's own distribution stations are currently slated for de-commissioning by the end of 2013 and therefore, limitations with respect to these stations will not be discussed.

In terms of the GPI electricity distribution system GPI has committed a long term strategy to rebuild most of its distribution infrastructure. The core of this strategy was to convert older 8.13kV distribution equipment to 27.6kV. This work usually encompasses replacing the older equipment (poles, transformers, and conductors) with equipment built to today's standards with increased clearances and capacities. This work is part of GPI's regular capital program and the 8.13kV distribution from GPI's two distribution substations is slated to be completed by the end of 2013.

To date GPI has had no inquiries with respect to any renewable generation in excess of 1MW. Given that renewable generation programs have been available for some time and have matured over a number of years it is likely that Grimsby will not be a centre for large scale solar or wind projects. This being said, the focus in Grimsby will be FIT and MicroFIT projects (<1MW) which are of a much smaller scale than the large developments. GPI sees no restrictions in the near future in the development of FIT and MicroFIT projects on its distribution system. In Grimsby renewable generation projects are in the early stages of development and only time and experience will identify potential issues.

There may however, be limitations with respect to the transmission stations. Hydro One has informally notified GPI of a limitation on the transmission side of the Beamsville TS. Hydro One's website publishes the short circuit capacity of this station at zero. The initial inquiry of the 1MW Biogas project to one of the NWTS feeders did not raise any concerns. However, NWTC has recently indicated informally that the short circuit capacity of this station has limitations.

Further information on the status of both TS's has not been made available to GPI and it is uncertain as to what course of action Hydro One or NWTC will take. GPI will continue to offer MicroFIT connections until formally notified by HO and NWTC. FIT connections are subject to impact assessments which will identify any issues prior to an offer to connect.

There are expenditures included in GPI's cost of service application for renewable generation. This is in the form of third party professional services to assist with GEA Plan development. $25,000 per year has been forecasted starting in 2012.

Grimsby Power has established limits for the amount of generation on each of its four 27.6kV feeders. These capacities are based on 50% of the feeder current carrying rating and are noted in Table 1 below:

Table 1:

Station	Feeder	Ampacity (Amps)	Capacity (MW)	Gen. Capacity (MW)	Existing Gen. (kW)	Avail. Gen (MW)	Known FIT Projects (kW)
Beamsville	M3	285	13.6	6.8	0	6.8	35
Beamsville	M4	70	3.2	1.6	25.6	1.6	96.7
NWTS	M3	285	13.6	6.8	10	6.8	67.9
NWTS	M4	385	18	9	20	9	1278.5

The feeder voltage of all feeders is 27.6kV and the capacities are subject to ongoing change due to ongoing connections.

2.2 Distribution System Development to Enable Renewable Generation Connections

Renewable connections over the next five years have been estimated using 2010's application and connection experience. There is a high level of uncertainty about the accuracy of this method of estimation. However, there is no methodology with which to predict future connections based on the limited experience GPI has with renewable generation connections. The estimated number of connections from 2011 onward is as shown below in Table 2.

Table 2:

Type of Project	2011	2012	2013	2014	2015	2016
MicroFIT Solar PV - <10kW	4	12	12	12	12	12
FIT - <10kW	0	0	0	0	0	0
FIT - >10kW <250kW	1	1	1	1	1	1
FIT - >250kW	1	1	1	1	1	1

It is anticipated that the above connections will be able to be connected using GPI's standard connection procedures.

The estimated generation by type of project is indicated in Table 3 below:

Table 3:

Type of Project	2011	2012	2013	2014	2015	2016
MicroFIT Solar PV - <10kW	29.2	87.6	87.6	87.6	87.6	87.6
FIT - <10kW	0	0	0	0	0	
FIT - >10kW <250kW	250	250	250	250	250	250
FIT - >250kW	1000	1000	1000	1000	1000	1000

In Table 3 all values are in kW. For MicroFIT Solar PV the average of 7.3kW per installation (from 2010) was used to forecast future values.

From a distribution perspective it is expected that all future projects in the five year horizon (Table 3) will be able to be connected with available capacity. However, as noted above, there is some uncertainty as to available capacities from both Hydro One and the Niagara West Transformer Station.

2.3 Renewable Connection Project Costs

GPI has had limited experience with the connection of only six MicroFIT customers to date. Costs for these projects have been assessed on an individual basis. To date the average cost for a MicroFIT renewable connection has been $564 of which the customer contributed 100% (contributed capital). These connections involved changes to metering only. It is anticipated that future connections will be similar to GPI's experience to date.

In terms of FIT projects, costs have not been established. These projects are not yet developed enough to estimate.

2.4 Renewable Connection Enablers

GPI is committed to establishing a customer friendly process which enables and promotes the efficient connection of renewable generation to the distribution system. GPI plans to modify its web based processes to help generators find the information they need to plan their project and to enable a seamless web application experience.

The number of applications and subsequent connections is not anticipated to require extra resources over and above what currently exists in GPI's organizational structure.

2.5 Smart Grid Development

GPI has been closely monitoring the development of Smart Grid projects in Ontario as well as other jurisdictions such as in the United States. Smart Grid development projects are for the most part in a discovery phase. Given GPI's excellent reliability, small service territory, and limited number of feeders it is not planning on performing any Smart Grid Pilot projects. GPI's strategy will be to monitor development in the Smart Grid arena and when sufficient progress is made in this area will evaluate projects on an individual basis as it may suit the needs of GPI's customers. Before projects can be undertaken a full cost benefit analysis must be completed.

It is anticipated that costs to monitor and keep up to date with Smart Grid development will be contained within GPI's existing cost structure.

Appendix 4.5 OPA – Response to GPI's Basic Green Energy Act Plan

OPA Letter of Comment: Grimsby Power Inc. Basic Green Energy Act Plan

April 25, 2011





ONTARIO
POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Grimsby Power Inc. Basic Green Energy Act Plan

On March 24, 2011, the OPA received a Basic GEA Plan from Grimsby Power Inc. ("GPI"). Total proposed expenditures for the five-year period covering this Plan are $25,000 per year starting in 2012, which are related to the connection of renewable generation. The OPA has reviewed GPI's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

GPI's Plan identifies 2 FIT applications and 27 microFIT applications received. These have been itemized by capacity and feeder in the Plan at pages 4 and 7.

To date, the OPA has received 1 capacity allocation exempt FIT application, 1 capacity allocation required FIT application and 34 microFIT applications to GPI's system for a total of 1.25 MW of FIT applications and 0.303 MW of microFIT applications. At this time, 6 microFIT applications have been connected and 2 microFIT applications have been terminated (leaving a total of 0.228 MW of microFIT applications to be connected).

Upstream Transmission Constraints

The OPA notes that GPI's service territory is constrained due to the fact that the Allanburg 115 kV TS has reached its short circuit limitation as specified by Hydro One. This constraint poses limitations for planned projects identified in GPI's current Plan for this area including capacity allocation exempt, capacity allocation required and microFIT projects. The OPA may be unable to award further FIT contracts in the area until this constraint has been addressed by Hydro One. This may result in some delay in connection of projects in the area.

Economic Connection Test Results

There has been no Economic Connection Test performed to date.

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that GPI's GEA Plan as filed is reasonably consistent with the OPA's information regarding known renewable energy generation connections.

The OPA appreciates the opportunity to comment on GPI's Basic GEA Plan.

Exhibit 5 Cost of Capital and Rate of Return

OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2012 Test year.

Capital Structure

Grimsby Power Inc. has a current deemed capital structure of 60% debt and 40% equity with returns of 7.25% and 9.00% respectively as approved in the 2006 EDR.

Grimsby Power Inc. has prepared this rate application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on Cost of Capital for Ontario's Regulated Utilities (the "2009 Report") issued December 11, 2009 and any subsequent updates.

Return on Equity:

Grimsby Power Inc. is requesting a return on equity ("ROE") for the 2012 Test year of 9.58% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. Grimsby Power Inc. understands that the OEB will be finalizing the ROE for 2012 Cost of Service Applications with an effective date of January 1, 2012 based on September 2011 market interest rate information.

Grimsby Power Inc. has provided historical, bridge and test year capitalization and cost of capital details in the Tables (5.1 through 5.8) below.

Capitalization / Cost of Capital (Board Appendix 2-N)

Table 5.1 2006

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	50.00%		$6,434,059	7.25%	$466,469
2	Short-term Debt		(1)	$ -		$ -
3	**Total Debt**	50.0%		$6,434,059	7.25%	$466,469
	Equity					
4	Common Equity	50.00%		$6,434,059	9.00%	$579,065
5	Preferred Shares			$ -		$ -
6	**Total Equity**	50.0%		$6,434,059	9.00%	$579,065
7	**Total**	100.0%		$12,868,118	8.13%	$1,045,535

Table 5.2 2007

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	50.00%		$6,540,947	7.25%	$474,219
2	Short-term Debt		(1)	$ -		$ -
3	**Total Debt**	50.0%		$6,540,947	7.25%	$474,219
	Equity					
4	Common Equity	50.00%		$6,540,947	9.00%	$588,685
5	Preferred Shares			$ -		$ -
6	**Total Equity**	50.0%		$6,540,947	9.00%	$588,685
7	**Total**	100.0%		$13,081,893	8.13%	$1,062,904

Table 5.3 2008

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	53.30%		$7,000,583	7.25%	$507,542
2	Short-term Debt		(1)	$ -		$ -
3	**Total Debt**	53.3%		$7,000,583	7.25%	$507,542
	Equity					
4	Common Equity	46.70%		$6,133,719	9.00%	$552,035
5	Preferred Shares			$ -		$ -
6	**Total Equity**	46.7%		$6,133,719	9.00%	$552,035
7	**Total**	100.0%		$13,134,302	8.07%	$1,059,577

Table 5.4 2009

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.70%		$7,625,017	7.25%	$552,814
2	Short-term Debt		(1)	$ -		$ -
3	**Total Debt**	56.7%		$7,625,017	7.25%	$552,814
	Equity					
4	Common Equity	43.30%		$5,822,985	9.00%	$524,069
5	Preferred Shares			$ -		$ -
6	**Total Equity**	43.3%		$5,822,985	9.00%	$524,069
7	**Total**	100.0%		$13,448,002	8.01%	$1,076,882

Table 5.5 2010

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	60.00%		$8,356,471	6.38%	$533,143
2	Short-term Debt		(1)	$ -		$ -
3	**Total Debt**	60.0%		$8,356,471	6.38%	$533,143
	Equity					
4	Common Equity	40.00%		$5,570,980	9.00%	$501,388
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$5,570,980	9.00%	$501,388
7	**Total**	100.0%		$13,927,451	7.43%	$1,034,531

Table 5.6 2011

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	60.00%		$9,003,399	5.83%	$525,337
2	Short-term Debt		(1)	$ -		$ -
3	**Total Debt**	60.0%		$9,003,399	5.83%	$525,337
	Equity					
4	Common Equity	40.00%		$6,002,266	9.00%	$540,204
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$6,002,266	9.00%	$540,204
7	**Total**	100.0%		$15,005,665	7.10%	$1,065,541

Table 5.7 2012 CGAAP

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$9,018,431	5.97%	$538,365
2	Short-term Debt	4.00%	(1)	$644,174	2.46%	$15,847
3	**Total Debt**	60.0%		$9,662,604	5.74%	$554,211
	Equity					
4	Common Equity	40.00%		$6,441,736	9.58%	$617,118
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$6,441,736	9.58%	$617,118
7	**Total**	100.0%		$16,104,341	7.27%	$1,171,330

Table 5.8 2012 MIFRS

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$9,148,693	5.97%	$546,141
2	Short-term Debt	4.00%	(1)	$653,478	2.46%	$16,076
3	**Total Debt**	60.0%		$9,802,171	5.74%	$562,216
	Equity					
4	Common Equity	40.00%		$6,534,781	9.58%	$626,032
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$6,534,781	9.58%	$626,032
7	**Total**	100.0%		$16,336,952	7.27%	$1,188,248

Cost of Capital (Return on Equity and Cost of Debt)

Table 5.9 details the debt and capital cost structure of Grimsby Power Inc. Descriptions of long and short term debt are detailed in the commentary below. The Prime interest rate has fluctuated between 2.25% and 3.00% during the term of Grimsby Power Inc.'s short and long term debt instruments. A blended interest rate of 3% has been used as the fixed rate in the Table 5.9 calculations.

- Cost of Debt:

- Long Term Debt:

  Grimsby Power Inc. is requesting a return on Long Term Debt for the 2012 Test Year of 5.97% and is based on a weighted average of Grimsby Power Inc.'s existing Debt instruments. Grimsby Power Inc.'s use of a Return on Long Term Debt of 5.97% is without prejudice to any revised rates that may be adopted by the OEB in early 2012. Details of the debt are noted below:

  - Promissory Note - $5,782,746 at an interest rate of 7.25%. A copy of the current promissory note with the Town of Grimsby is included as Appendix 5.1.

  - Funding for Smart Meter Implementation & Capital Projects

    Grimsby Power Inc. began their smart meter installation program in 2009 and by December 31, 2010 had installed 97.6% of their smart meters. In 2011 Grimsby Power Inc. arranged financing (for long term debt) with TD Commercial Banking to fund this initiative as well as a small portion of its distribution capital projects. Specifically on May 01, 2011, Grimsby Power Inc. entered into a 15 year, term loan at a rate of Prime Rate plus 0.50% per annum in the amount of $1,600,000.

  - Funding for 2011 Capital Projects

    Grimsby Power Inc. plans to borrow $1,500,000 in 2012 to fund its 2011 capital projects. This instrument is anticipated to be organized in a similar fashion to the debt instrument taken out with TD Commercial Banking in 2011.

- Short Term Debt

Grimsby Power Inc. is requesting a return on Short Term Debt for the 2012 Test year of 2.46% in accordance with the Cost of Capital Parameter Updates for 2011 Cost of Service Applications issued by the OEB on March 3, 2011. Grimsby Power Inc. understands that the OEB will be finalizing the return on short term debt for 2012 Cost of Service Applications with an effective date of January 1, 2012 based on September 2011 market interest rate information. Grimsby Power Inc.'s use of a Return on Short Term Debt of 2.46% is without prejudice to any revised rates that may be adopted by the OEB.

In April 2010 Grimsby Power Inc entered into an Operating Loan agreement with TD Commercial Banking for $1.6 million at the prime rate + 0.00% interest. There were three installments: $ 700,000 in April, $ 600,000 in August and $ 300,000 in December. The interest paid ranged from 2.5% from April to end of August 2010, to 3% from September 2010 to end of April 2011. On May 1, 2011 the Operating Loan was converted to a term loan at prime + 0.50% as noted above under "Smart Meter Implementation & Capital Projects". As of the date of filing this application the 2011 operating loan for $1.5 million has not been organized.

Table 5.9 Debt and Capital Cost Structure

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Promissory Note	Town of Grimsby	Y	January 1, 2004	5,782,746	20	7.25%	2006	419,249
Promissory Note	Town of Grimsby	Y		5,782,746	20	7.25%	2007	419,249
Promissory Note	Town of Grimsby	Y		5,782,746	20	7.25%	2008	419,249
Promissory Note	Town of Grimsby	Y		5,782,746	20	7.25%	2009	419,249
Promissory Note	Town of Grimsby	Y		5,782,746	20	7.25%	2010	419,249
Smart Meter/Capital Financing	TD Commercal Bank	N	April 1, 2010	1,493,333	15	3.00%	2010	44,800
Promissory Note	Town of Grimsby	Y		5,782,746	20	7.25%	2011	419,249
Smart Meter/Capital Financing	TD Commercal Bank	N		2,886,667	15	3.00%	2011	86,600
Promissory Note	Town of Grimsby	Y		5,782,746	20	7.25%	2012	419,249
Smart Meter/Capital Financing	TD Commercal Bank	N		2,493,333	15	3.00%	2012	74,800
								0
								0
								0
								0
								0
								0
								0

2006 Total Long Term Debt	5,782,746	**Total Interest Cost for 2006**	419,249
		Weighted Debt Cost Rate for 2006	7.25%
2007 Total Long Term Debt	5,782,746	**Total Interest Cost for 2007**	419,249
		Weighted Debt Cost Rate for 2007	7.25%
2008 Total Long Term Debt	5,782,746	**Total Interest Cost for 2008**	419,249
		Weighted Debt Cost Rate for 2008	7.25%
2009 Total Long Term Debt	5,782,746	**Total Interest Cost for 2009**	419,249
		Weighted Debt Cost Rate for 2009	7.25%
2010 Total Long Term Debt	7,276,079	**Total Interest Cost for 2010**	464,049
		Weighted Debt Cost Rate for 2010	6.38%
2011 Total Long Term Debt	8,669,413	**Total Interest Cost for 2011**	505,849
		Weighted Debt Cost Rate for 2011	5.83%
2012 Total Long Term Debt	8,276,079	**Total Interest Cost for 2012**	494,049
		Weighted Debt Cost Rate for 2012	5.97%

Appendix 5.1 Town of Grimsby Promissory Note

PROMISSORY NOTE

Due: February 1, 2020

FOR VALUE RECEIVED, Grimsby Power Incorporated (“the Corporation) unconditionally promises to pay to or to the order of The Corporation of the Town of Grimsby (“the Town”) the sum of $5,782,746.01 (Five Million, Seven Hundred and Eighty-two Thousand, Seven Hundred and Forty-six Dollars and one cent) and to pay interest from April 1, 2001 (being the first day of the month following approval of the distribution rates for the Corporation by the Ontario Energy Board) at the rate of 7.25% per annum. Interest at the aforesaid rate shall be payable annually to the Town on the 30th day after the Corporation’s fiscal year.” And

THAT the amendment as noted take effect January 1, 2004; and

THAT the Authorized Officers of Grimsby Power Incorporated sign the note as amended.”

Any shortfall in payment described shall accrue to the principal sum of this note and shall be assessed interest at the rate as described herein.

At the option of the Town, on one year’s prior written notice to the Corporation, the Maturity Date and any of the terms of this Promissory Note may be revised, changed or restated by the Town in consultation with the Corporation.

The principal and interest of this Promissory Note shall be in Canadian dollars without set-off or counterclaim.

This note is not assignable by the Town without the consent of the Corporation.

Made at Grimsby, Ontario this 18th day of December 2007.

GRIMSBY POWER INCORPORATED

Per:

____

Chair: Brian A. Weber

Exhibit 6 Calculation of Revenue

OVERVIEW

Grimsby Power Inc.'s net revenue deficiency is $812,776. This deficiency is calculated as the difference between the 2012 Test Year Revenue Requirement of $4,583,444 and the Forecast 2012 Test Year Revenue Requirement at Grimsby Power Inc.'s 2011 approved distribution rates of $3,770,668. Table 6.1 below provides the revenue deficiency calculations for the 2012 Test Year at Existing 2011 OEB-approved rates and the 2012 Test Year Revenue Requirement.

Table 6.1 Revenue Deficiency Determination

Description	2011 Bridge Actual	2012 Test Existing Rates	2012 Test - Required Revenue
Revenue			
Revenue Deficiency			**812,776**
Distribution Revenue	3,409,489	3,430,927	3,430,927
Other Operating Revenue (Net)	331,700	339,741	339,741
Total Revenue	**3,741,189**	**3,770,668**	**4,583,444**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,359,294	1,653,300	1,653,300
Operation & Maintenance	690,251	938,840	938,840
Depreciation & Amortization	1,025,789	709,099	709,099
Property Taxes	27,000	27,540	27,540
Other - LEAP program	3,974	4,117	4,117
Capital Taxes	0	0	0
Deemed Interest	525,337	562,216	562,216
Total Costs and Expenses	**3,631,644**	**3,895,113**	**3,895,113**
Less OCT Included Above	0	0	0
Total Costs and Expenses Net of OCT	**3,631,644**	**3,895,113**	**3,895,113**
Utility Income Before Income Taxes	**109,545**	**(124,444)**	**688,331**
Income Taxes:			
Corporate Income Taxes	43,786	(63,681)	62,299
Total Income Taxes	**43,786**	**(63,681)**	**62,299**
Utility Net Income	**65,759**	**(60,763)**	**626,032**
Capital Tax Expense Calculation:			
Total Rate Base	15,005,665	16,336,952	16,336,952
Exemption	0	0	0
Deemed Taxable Capital	**15,005,665**	**16,336,952**	**16,336,952**
Ontario Capital Tax	0	0	0
Income Tax Expense Calculation:			
Accounting Income	109,545	(124,444)	688,331
Tax Adjustments to Accounting Income	45,451	(286,400)	(286,400)
Taxable Income	**154,996**	**(410,844)**	**401,932**
Income Tax Expense	43,786	(63,681)	62,299
Tax Rate Refecting Tax Credits	28.25%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	15,005,665	16,336,952	16,336,952
Interest Expense	525,337	562,216	562,216
Net Income	65,759	(60,763)	626,032
Total Actual Return on Rate Base	**591,095**	**501,453**	**1,188,248**
Actual Return on Rate Base	3.94%	3.07%	7.27%
Required Return on Rate Base:			
Rate Base	15,005,665	16,336,952	16,336,952
Return Rates:			
Return on Debt (Weighted)	5.83%	5.74%	5.74%
Return on Equity	9.00%	9.58%	9.58%
Deemed Interest Expense	525,337	562,216	562,216
Return On Equity	540,204	626,032	626,032
Total Return	**1,065,541**	**1,188,248**	**1,188,248**
Expected Return on Rate Base	7.10%	7.27%	7.27%
Revenue Deficiency After Tax	**474,445**	**686,795**	**0**
Revenue Deficiency Before Tax	**661,248**	**812,776**	**0**

REVENUE REQUIREMENT

Grimsby Power Inc.'s Revenue Requirement consists of the following:

- Operation, Maintenance & Administration Expense
- Amortization/Depreciation Expense
- Property Taxes
- LEAP Program
- PILS'
- Deemed Interest & Return on Equity

Grimsby Power Inc.'s revenue requirement is primarily received through electricity distribution rates and offset by revenue from OEB-approved specific service charges, late payment charges, interest, and other operating income.

COST DRIVERS ON REVENUE DEFICIENCY

The Applicant notes there are several factors that contribute to the revenue deficiency of $812,776 for the 2012 Test Year. However, two factors which are most significant are the implementation of smart meter infrastructure and the increase in OM&A which is partially offset by a reduction of depreciation expense. Based on the revenue requirement model for smart meters and based on the 2011 calculations the shortfall in revenue for smart meters is approximately $400K. In terms of OM&A, of the $818K increase from 2010 to 2012, $163K is due to the change in distributed allocations resulting from the implementation of MIFRS. This is offset by a decrease in depreciation of approximately $300K, also a result of MIFRS. The following discussion highlights the major items that contribute to this deficiency.

Operations, Maintenance, Administration, & Amortization/ Depreciation Expense

Grimsby Power Inc. OM&A costs have increased since the last rebasing application in 2006. Cost increases over this period amount to $1,056,704. This increase is described in detail in Exhibit 4. Grimsby Power Inc.'s amortization/depreciation expense under CGAAP for the period 2006 – 2012 stayed relatively stable at an average value of $937,037. However, in 2012 depreciation rates changed as a result of the implementation of IFRS. 2012's depreciation expense was reduced by $449,215. The transition from CGAAP to IFRS is described in Exhibit 4. The decrease in amortization/depreciation expense partially offsets the increase in OM&A and the resulting effect is a net increase in costs and expenses.

Net Book Value of Assets

Grimsby Power Inc.'s average net book value of assets has increased from 2006 ($10,241,861) to 2012 (IFRS) ($13,369,860) by $3,127,999. This is a result of an aggressive capital rebuild program and the addition of smart meter infrastructure.

Return on Equity

For the period since the last rebasing in 2006 the deemed return on equity was 9.00%. The deemed rate of return in the cost of service application is 9.58% which in isolation has the effect of a net increase in return on equity.

Exhibit 7 Cost Allocation

OVERVIEW

In 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. On March 31, 2011 the Board issued the Review of Electricity Distribution Cost Allocation Policy, EB-2010-0219. Grimsby Power Inc. has prepared a 2012 cost allocation study consistent with Grimsby Power Inc.'s understanding of the Directions, the Guidelines, the Model and the Instructions. Grimsby Power Inc. has utilized 2012 test year costs, customer numbers and demand values. The 2012 demand values are based on the weather normalized load forecast used to design rates.

SUMMARY OF RESULTS AND PROPOSED CHANGES

The data used in the cost allocation study is consistent with Grimsby Power Inc.'s cost data that supports the proposed 2012 revenue requirement outlined in this application. Consistent with the Guidelines, Grimsby Power Inc.'s assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation informational filing filed on February 27, 2007. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available, its engineering records, and its customer and financial information systems. An Excel version of the updated cost allocation study has been filed with this application. Included in Appendix 7.1 are copies of the output sheets I-6, I-8, O-1, and O-2.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2012 continuity statement shown in

Exhibit 2. The rate class customer data used in the cost allocation study is consistent with the 2012 customer forecast outlined in Exhibit 3.

The load profiles used for all rate classes are the same as those used in the original information filing but have been scaled to match the load forecast. The following Table 7.1 outlines the scaling factors used by rate class.

Table 7.1 Cost Allocation – Scaling factors (Board Appendix 2-O)

Classes	Previous Cost Allocation Study	2012 Cost Allocation Study	Scaling Factor
Residential	86,181,393	92,606,843	1.07
GS < 50 kW	18,082,932	18,314,894	1.01
GS > 50 kW	57,699,153	68,877,755	1.19
Street Lighting	1,618,360	1,578,145	0.98
Unmetered Scattered Load (USL)	390,158	355,293	0.91
Standby Power	1,683,163		-
Total	165,655,159	181,732,931	

The allocated cost by rate class for the February 27, 2007 information filing and 2012 updated study are provided in the following Table 7.2.

Table 7.2 Cost Allocation – Allocated Costs (Board Appendix 2-O)

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 2,261,917	63.8%	$ 3,100,569	67.6%
GS < 50 kW	$ 462,371	13.0%	$ 544,637	11.9%
GS > 50 kW	$ 447,961	12.6%	$ 730,000	15.9%
Street Lighting	$ 296,303	8.4%	$ 176,913	3.9%
Unmetered Scattered Load (USL)	$ 31,819	0.9%	$ 31,324	0.7%
Standby Power	$ 47,188	1.3%		0.0%
Total	$ 3,547,560	100.0%	$ 4,583,444	100.0%

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

As per the Boards report, dated March 31, 2011, the acceptable revenue to cost ratios have been updated. These ratios are reproduced below in Table 7.3. In addition Table 7.4 provides the detailed analysis in calculating Grimsby Power Inc.'s revenue to cost ratios. With the exception of the Street Lighting classification all classes are within Board targets and thus no changes to those ratios will be contemplated. Grimsby Power Inc proposes to move the Street Lighting revenue to cost ratio to be within the Board's target range over a three year period. The additional revenue from the Street Lighting class will be used to reduce the revenue to cost ratio for the Residential class.

Table 7.3 Revenue to Cost Ratios (Board Appendix 2-O)

Class	Previously Report Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2006	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	111.9%	109.6%	108.4%	85 - 115
GS < 50 kW	95.5%	96.3%	96.3%	80 - 120
GS > 50 kW	99.8%	80.3%	80.3%	80 - 120
Street Lighting	17.1%	28.7%	49.4%	70 - 120
Unmetered Scattered Load (USL)	74.0%	76.2%	80.0%	80 - 120

The resulting proposed revenues by rate class reflecting the proposed revenue to cost ratios is provided in the following Table 7.4:

Table 7.4 Calculated Class Revenues (Board Appendix 2-O)

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C LF X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$ 2,555,823	$ 3,161,289	$ 3,123,569	$ 237,168
GS < 50 kW	$ 392,621	$ 485,632	$ 485,632	$ 38,873
GS > 50 kW	$ 432,269	$ 534,672	$ 534,672	$ 51,155
Street Lighting	$ 34,428	$ 42,584	$ 79,108	$ 8,207
Unmetered Scattered Load (USL)	$ 15,786	$ 19,526	$ 20,721	$ 4,338
Total	$ 3,430,927	$ 4,243,703	$ 4,243,703	$ 339,741

The proposed revenue to cost ratios for 2012 to 2014 are provided in the following Table 7.5 which shows the movement in the revenue to cost ratios for the Street Lighting and Residential classes over the three years.

Table 7.5 Proposed Revenue-to-Cost Ratios (Board Appendix 2-O)

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2012	2013	2014	
	%	%	%	%
Residential	108.4%	107.8%	107.2%	85 - 115
GS < 50 kW	96.3%	96.3%	96.3%	80 - 120
GS > 50 kW	80.3%	80.3%	80.3%	80 - 120
Street Lighting	49.4%	59.7%	70.0%	70 - 120
Unmetered Scattered Load (USL)	80.0%	80.0%	80.0%	80 - 120

Appendix 7.1 Cost Allocation Model

Input Sheet I-6

Ontario

2012 COST ALLOCATION STUDY
Grimsby Power Incorporated

Friday, June 24, 2011
Sheet I6 Customer Data Worksheet - First Run

Total kWhs	181,732,931
Total kWs	193,126
Total Approved Distribution Revenue ($)	$4,243,703

Billing Data

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	9 Unmetered Scattered Load	11 Back-up/Standby Power
kWh from load forecasting model	CEN	181,732,931	92,606,843	18,314,894	68,877,755	1,578,145	355,293	
kW from load forecasting model	CDEM	193,126	-	-	188,723	4,403	-	
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		-						
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	181,732,931	92,606,843	18,314,894	68,877,755	1,578,145	355,293	
kWh - weather normalized amount from load forecast		181,732,931	92,606,843	18,314,894	68,877,755	1,578,145	355,293	
Proposed Distribution Rev	CREV	$4,243,703	$3,161,289	$485,632	$534,672	$42,584	$19,526	
Bad Debt	BDHA	$6,000	$1,639	$521	$3,839	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$55,000	$38,095	$4,920	$11,519	$180	$287	$0
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	10.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	5.0	7.0
Number of Bills	CNB	126,821	116,440	8,195	1,202	24	960	
Number of Connections (Unmetered)	CCON	2,037				1,957	80	
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	10,486	9,703	683	100			
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	10,486	9,703	683	100			
Line Transformer Customer Base	CCLT	10,479	9,703	683	93			
Secondary Customer Base	CCS	10,386	9,703	683	-			
Weighted - Services	CWCS	13,106	9,703	1,366	-	1,957	80	-
Weighted Meter -Capital	CWMC	1,520,528	1,261,430	140,698	118,400	-	-	-
Weighted Meter Reading	CWMR	10,486	9,703	683	100	-	-	-
Weighted Bills	CWNB	146,071	116,440	16,391	8,417	24	4,800	-
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		4,243,703	3,161,289	485,632	534,672	42,584	19,526	-

Weather Normalized Data from Hydro

Click Here For Instructions on How to Complete This Section

	Total	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load	Back-up/Standby Power
kWh - weather normalized amount from load forecast	165,655,159	86,181,393	18,082,932	57,699,153	1,618,360	390,158	1,683,163
2006 EDR Distribution Loss Factor		1.0502	1.0502	1.0502	1.0502	1.0502	1.0502

Bad Debt Data from EDR 2006

Click Here For Instructions on How to Complete This Section

Sheet ADJ5 rows 26 - 32, column E	3,826	4,393	128	(695)			
Sheet ADJ5 rows 26 - 32, column F	33,895	7,800	95	26,000			
Sheet ADJ5 rows 26 - 32, column G	1,824	(1,389)	3,213	-			
Three-year average	13,182	3,601	1,145	8,435	-	-	-

Input Sheet I-8

2012 COST ALLOCATION STUDY
Grimsby Power Incorporated

Friday, June 24, 2011
Sheet I8 Demand Data Worksheet - First Run

This is an input sheet for demand allocators.

CP TEST RESULTS	4 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	9 Unmetered Scattered Load	11 Back-up/Standby Power
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	38,218	20,870	5,300	12,010	-	39	-
Bulk Delivery CP	BCP1	38,218	20,870	5,300	12,010	-	39	-
Total Sytem CP	DCP1	38,218	20,870	5,300	12,010	-	39	-
4 CP								
Transformation CP	TCP4	141,141	78,635	20,222	42,133	-	151	-
Bulk Delivery CP	BCP4	141,141	78,635	20,222	42,133	-	151	
Total Sytem CP	DCP4	141,141	78,635	20,222	42,133	-	151	
12 CP								
Transformation CP	TCP12	360,068	193,492	45,271	118,128	2,689	487	-
Bulk Delivery CP	BCP12	360,068	193,492	45,271	118,128	2,689	487	
Total Sytem CP	DCP12	360,068	193,492	45,271	118,128	2,689	487	
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	41,601	22,449	5,757	12,951	387	56	0
Primary NCP	PNCP1	41,601	22,449	5,757	12,951	387	56	-
Line Transformer NCP	LTNCP1	40,696	22,449	5,757	12,047	387	56	-
Secondary NCP	SNCP1	28,649	22,449	5,757	-	387	56	-
4 NCP								
Classification NCP from Load Data Provider	DNCP4	150,999	80,495	21,264	47,522	1,525	192	0
Primary NCP	PNCP4	150,999	80,495	21,264	47,522	1,525	192	-
Line Transformer NCP	LTNCP4	147,679	80,495	21,264	44,202	1,525	192	-
Secondary NCP	SNCP4	103,476	80,495	21,264	-	1,525	192	-
12 NCP								
Classification NCP from Load Data Provider	DNCP12	380,763	199,166	47,497	129,156	4,435	509	0
Primary NCP	PNCP12	380,763	199,166	47,497	129,156	4,435	509	-
Line Transformer NCP	LTNCP12	371,740	199,166	47,497	120,133	4,435	509	-
Secondary NCP	SNCP12	251,606	199,166	47,497	-	4,435	509	-

Output Sheet O-1

2012 COST ALLOCATION STUDY
Grimsby Power Incorporated

Ontario

Friday, June 24, 2011
Sheet O1 Revenue to Cost Summary Worksheet - First Run

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	9	11
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load	Back-up/Standby Power
crev	Distribution Revenue (sale)	$4,243,703	$3,161,289	$485,632	$534,672	$42,584	$19,526	$0
mi	Miscellaneous Revenue (mi)	$339,741	$237,168	$38,873	$51,155	$8,207	$4,338	$0
	Total Revenue	$4,583,444	$3,398,457	$524,505	$585,828	$50,790	$23,864	$0
	Expenses							
di	Distribution Costs (di)	$885,961	$545,999	$114,152	$173,055	$50,401	$2,354	$0
cu	Customer Related Costs (cu)	$641,131	$530,751	$62,724	$33,165	$803	$13,687	$0
ad	General and Administration (ad)	$1,096,705	$769,763	$127,432	$150,991	$37,422	$11,098	$0
dep	Depreciation and Amortization (dep)	$709,099	$458,921	$85,526	$132,813	$30,398	$1,441	$0
INPUT	PILs (INPUT)	$62,299	$39,612	$7,712	$11,955	$2,884	$137	$0
INT	Interest	$562,216	$357,474	$69,595	$107,888	$26,026	$1,234	$0
	Total Expenses	$3,957,412	$2,702,519	$467,142	$609,867	$147,933	$29,950	$0
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$626,032	$398,050	$77,495	$120,134	$28,980	$1,374	$0
	Revenue Requirement (includes NI)	$4,583,444	$3,100,569	$544,637	$730,000	$176,913	$31,324	$0
		Revenue Requirement Input equals Output						
		$0						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$24,385,228	$15,157,746	$3,073,469	$4,945,587	$1,153,330	$55,096	$0
gp	General Plant - Gross	$3,191,653	$2,029,348	$395,088	$612,468	$147,745	$7,004	$0
accum dep	Accumulated Depreciation	($14,207,021)	($8,686,139)	($1,813,531)	($2,992,422)	($682,169)	($32,760)	$0
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	$13,369,860	$8,500,955	$1,655,025	$2,565,634	$618,906	$29,341	$0
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$17,156,811	$8,742,709	$1,729,049	$6,502,523	$148,988	$33,542	$0
	OM&A Expenses	$2,623,797	$1,846,513	$304,308	$357,211	$88,625	$27,139	$0
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$19,780,608*	*$10,589,222*	*$2,033,358*	*$6,859,735*	*$237,613*	*$60,681*	*$0*
	Working Capital	$2,967,091	$1,588,383	$305,004	$1,028,960	$35,642	$9,102	$0
	Total Rate Base	$16,336,952	$10,089,338	$1,960,029	$3,594,594	$654,548	$38,443	$0
		Rate Base Input equals Output						
	Equity Component of Rate Base	$6,534,781	$4,035,735	$784,012	$1,437,838	$261,819	$15,377	$0
	Net Income on Allocated Assets	$626,032	$695,937	$57,363	($24,039)	($97,143)	($6,086)	$0
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$626,032	$695,937	$57,363	($24,039)	($97,143)	($6,086)	$0
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	109.61%	96.30%	80.25%	28.71%	76.18%	0.00%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$0	$297,888	($20,132)	($144,173)	($126,123)	($7,460)	$0
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.58%	17.24%	7.32%	-1.67%	-37.10%	-39.58%	0.00%

Output Sheet O-2

2012 COST ALLOCATION STUDY

Grimsby Power Incorporated

Ontario

Friday, June 24, 2011

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - First Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	9	11
	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load	Back-up/Standby Power
Customer Unit Cost per month - Avoided Cost	$5.79	$9.39	$29.52	$0.03	$12.91	$0.00
Customer Unit Cost per month - Directly Related	$9.26	$15.20	$49.44	$0.05	$22.67	$0.00
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$14.18	$21.02	$54.92	$7.52	$25.34	$0.00
Fixed Charge per approved 2011	$15.11	$25.55	$165.08	$0.66	$12.78	$0.00

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	7	9	11
	Total	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load	Back-up/Standby Power
General Plant - Gross Assets	$3,191,653	$2,029,348	$395,088	$612,468	$147,745	$7,004	$0
General Plant - Accumulated Depreciation	($2,004,934)	($1,274,797)	($248,186)	($384,740)	($92,811)	($4,400)	$0
General Plant - Net Fixed Assets	$1,186,719	$754,551	$146,901	$227,728	$54,935	$2,604	$0
General Plant - Depreciation	$167,689	$106,622	$20,758	$32,179	$7,763	$368	$0
Total Net Fixed Assets Excluding General Plant	$12,183,141	$7,746,404	$1,508,124	$2,337,906	$563,971	$26,736	$0
Total Administration and General Expense	$1,096,705	$769,763	$127,432	$150,991	$37,422	$11,098	$0
Total O&M	$1,527,092	$1,076,750	$176,877	$206,220	$51,204	$16,041	$0

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	7	9	11	
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Unmetered Scattered Load**	**Back-up/Standby Power**	
	Distribution Plant								
1860	Meters	$1,719,942	$1,426,864	$159,150	$133,928	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($226,409)	($187,829)	($20,950)	($17,630)	$0	$0	$0	
	Meter Net Fixed Assets	**$1,493,533**	**$1,239,035**	**$138,200**	**$116,298**	**$0**	**$0**	**$0**	
	Misc Revenue								
4082	Retail Services Revenues	($25,591)	($20,400)	($2,872)	($1,475)	($4)	($841)	$0	CWNB
4084	Service Transaction Requests (STR) Revenues	($800)	($638)	($90)	($46)	($0)	($26)	$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	($55,000)	($38,095)	($4,920)	($11,519)	($180)	($287)	$0	LPHA
	Sub-total	*($81,391)*	*($59,133)*	*($7,881)*	*($13,039)*	*($184)*	*($1,154)*	*$0*	
	Operation								
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$4,701	$3,642	$256	$38	$735	$30	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$4,701*	*$3,642*	*$256*	*$38*	*$735*	*$30*	*$0*	
	Maintenance								
5175	Maintenance of Meters	$48,178	$39,968	$4,458	$3,752	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$166,644	$154,202	$10,853	$1,589	$0	$0	$0	CWMR
5315	Customer Billing	$360,711	$287,539	$40,475	$20,784	$59	$11,853	$0	CWNB
5320	Collecting	$43,983	$35,061	$4,935	$2,534	$7	$1,445	$0	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$6,630	$5,285	$744	$382	$1	$218	$0	CWNB
	Sub-total	$577,968	$482,086	$57,008	$25,290	$68	$13,516	$0	
	Total Operation, Maintenance and Billing	$630,847	$525,697	$61,722	$29,079	$802	$13,546	$0	
	Amortization Expense - Meters	$110,147	$91,378	$10,192	$8,577	$0	$0	$0	
	Allocated PILs	$6,959	$5,774	$644	$542	$0	$0	$0	
	Allocated Debt Return	$62,805	$52,103	$5,811	$4,890	$0	$0	$0	
	Allocated Equity Return	$69,933	$58,017	$6,471	$5,446	$0	$0	$0	
	Total	**$799,301**	**$673,836**	**$76,960**	**$35,495**	**$618**	**$12,393**	**$0**	

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	7	9	11	
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Unmetered Scattered Load**	**Back-up/Standby Power**	
	Distribution Plant								
1860	Meters	$1,719,942	$1,426,864	$159,150	$133,928	$0	$0	$0	CWMC
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($226,409)	($187,829)	($20,950)	($17,630)	$0	$0	$0	
	Meter Net Fixed Assets	$1,493,533	$1,239,035	$138,200	$116,298	$0	$0	$0	
	Allocated General Plant Net Fixed Assets	$145,480	$120,690	$13,462	$11,328	$0	$0	$0	
	Meter Net Fixed Assets Including General Plant	$1,639,014	$1,359,726	$151,662	$127,626	$0	$0	$0	
	Misc Revenue								
4082	Retail Services Revenues	($25,591)	($20,400)	($2,872)	($1,475)	($4)	($841)	$0	CWNB
4084	Service Transaction Requests (STR) Revenues	($800)	($638)	($90)	($46)	($0)	($26)	$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	($55,000)	($38,095)	($4,920)	($11,519)	($180)	($287)	$0	LPHA
	Sub-total	*($81,391)*	*($59,133)*	*($7,881)*	*($13,039)*	*($184)*	*($1,154)*	*$0*	
	Operation								
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$4,701	$3,642	$256	$38	$735	$30	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
	Sub-total	*$4,701*	*$3,642*	*$256*	*$38*	*$735*	*$30*	*$0*	
	Maintenance								
5175	Maintenance of Meters	$48,178	$39,968	$4,458	$3,752	$0	$0	$0	1860
	Billing and Collection								
5310	Meter Reading Expense	$166,644	$154,202	$10,853	$1,589	$0	$0	$0	CWMR
5315	Customer Billing	$360,711	$287,539	$40,475	$20,784	$59	$11,853	$0	CWNB
5320	Collecting	$43,983	$35,061	$4,935	$2,534	$7	$1,445	$0	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$6,630	$5,285	$744	$382	$1	$218	$0	CWNB
	Sub-total	*$577,968*	*$482,086*	*$57,008*	*$25,290*	*$68*	*$13,516*	*$0*	
	Total Operation, Maintenance and Billing	$630,847	$525,697	$61,722	$29,079	$802	$13,546	$0	
	Amortization Expense - Meters	$110,147	$91,378	$10,192	$8,577	$0	$0	$0	
	Amortization Expense - General Plant assigned to Meters	*$20,557*	*$17,054*	*$1,902*	*$1,601*	*$0*	*$0*	*$0*	
	Admin and General	$451,535	$375,818	$44,468	$21,291	$586	$9,372	$0	
	Allocated PILs	$7,637	$6,336	$707	$595	$0	$0	$0	
	Allocated Debt Return	$68,922	$57,178	$6,378	$5,367	$0	$0	$0	
	Allocated Equity Return	$76,745	$63,668	$7,101	$5,976	$0	$0	$0	
	Total	**$1,285,001**	**$1,077,996**	**$124,589**	**$59,446**	**$1,204**	**$21,764**	**$0**	

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	9 Unmetered Scattered Load	11 Back-up/Standby Power	
	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	$1,905,794	$1,476,630	$103,929	$15,248	$297,812	$12,174	$0	PNCP
1830-5	Poles, Towers and Fixtures - Secondary	$476,448	$372,135	$26,192	$0	$75,054	$3,068	$0	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	$566,051	$438,583	$30,869	$4,529	$88,455	$3,616	$0	PNCP
1835-5	Overhead Conductors and Devices - Secondary	$141,513	$110,530	$7,779	$0	$22,292	$911	$0	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	$1,162,473	$900,697	$63,393	$9,301	$181,656	$7,426	$0	PNCP
1840-5	Underground Conduit - Secondary	$129,164	$100,885	$7,101	$0	$20,347	$832	$0	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	$362,507	$280,875	$19,769	$2,900	$56,648	$2,316	$0	PNCP
1845-5	Underground Conductors and Devices - Secondary	$3,662	$2,860	$201	$0	$577	$24	$0	SNCP
1850	Line Transformers	$2,180,786	$1,690,642	$118,992	$16,238	$340,975	$13,939	$0	LTNCP
1855	Services	$465,542	$344,669	$48,517	$0	$69,514	$2,842	$0	CWCS
1860	Meters	$1,719,942	$1,426,864	$159,150	$133,928	$0	$0	$0	CWMC
	Sub-total	*$9,113,882*	*$7,145,369*	*$585,892*	*$182,145*	*$1,153,330*	*$47,147*	*$0*	
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($3,996,839)	($3,110,020)	($229,927)	($43,442)	($589,358)	($24,092)	$0	
	Customer Related Net Fixed Assets	$5,117,042	$4,035,349	$355,965	$138,703	$563,971	$23,055	$0	
	Allocated General Plant Net Fixed Assets	$498,434	$393,070	$34,673	$13,511	$54,935	$2,246	$0	
	Customer Related NFA Including General Plant	$5,615,476	$4,428,419	$390,638	$152,213	$618,906	$25,300	$0	
	Misc Revenue								
4082	Retail Services Revenues	($25,591)	($20,400)	($2,872)	($1,475)	($4)	($841)	$0	CWNB
4084	Service Transaction Requests (STR) Revenues	($800)	($638)	($90)	($46)	($0)	($26)	$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	($55,000)	($38,095)	($4,920)	($11,519)	($180)	($287)	$0	LPHA
4235	Miscellaneous Service Revenues	($85,350)	($68,036)	($9,577)	($4,918)	($14)	($2,805)	$0	CWNB
	Sub-total	*($166,741)*	*($127,169)*	*($17,458)*	*($17,957)*	*($198)*	*($3,958)*	*$0*	
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$18,195	$14,072	$1,050	$119	$2,838	$116	$0	1815-1855
5010	Load Dispatching	$0	$0	$0	$0	$0	$0	$0	1815-1855
5020	Overhead Distribution Lines and Feeders - Operation Labour	$11,280	$8,754	$616	$72	$1,765	$72	$0	1830 & 1835
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$3,603	$2,796	$197	$23	$564	$23	$0	1830 & 1835
5035	Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	1850
5040	Underground Distribution Lines and Feeders - Operation Labour	$9,347	$7,247	$510	$69	$1,462	$60	$0	1840 & 1845
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0	1840 & 1845
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	1850
5065	Meter Expense	$0	$0	$0	$0	$0	$0	$0	CWMC
5070	Customer Premises - Operation Labour	$4,701	$3,642	$256	$38	$735	$30	$0	CCA
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	CCA
5085	Miscellaneous Distribution Expense	$91,887	$71,066	$5,303	$599	$14,333	$586	$0	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	$7,727	$5,997	$422	$49	$1,209	$49	$0	1830 & 1835
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	O&M
5105	Maintenance Supervision and Engineering	$15,432	$11,935	$891	$101	$2,407	$98	$0	1815-1855
5120	Maintenance of Poles, Towers and Fixtures	$12,034	$9,339	$657	$77	$1,884	$77	$0	1830
5125	Maintenance of Overhead Conductors and Devices	$24,851	$19,286	$1,357	$159	$3,890	$159	$0	1835
5130	Maintenance of Overhead Services	$67,233	$49,777	$7,007	$0	$10,039	$410	$0	1855
5135	Overhead Distribution Lines and Feeders - Right of Way	$23,296	$18,079	$1,272	$149	$3,646	$149	$0	1830 & 1835
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	1840
5150	Maintenance of Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	1845
5155	Maintenance of Underground Services	$13,817	$10,230	$1,440	$0	$2,063	$84	$0	1855
5160	Maintenance of Line Transformers	$27,505	$21,323	$1,501	$205	$4,301	$176	$0	1850
5175	Maintenance of Meters	$48,178	$39,968	$4,458	$3,752	$0	$0	$0	1860
	Sub-total	*$379,087*	*$293,512*	*$26,938*	*$5,411*	*$51,136*	*$2,090*	*$0*	
	Billing and Collection								
5305	Supervision	$4,284	$3,415	$481	$247	$1	$141	$0	CWNB
5310	Meter Reading Expense	$166,644	$154,202	$10,853	$1,589	$0	$0	$0	CWMR
5315	Customer Billing	$360,711	$287,539	$40,475	$20,784	$59	$11,853	$0	CWNB
5320	Collecting	$43,983	$35,061	$4,935	$2,534	$7	$1,445	$0	CWNB
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	CWNB
5330	Collection Charges	$6,630	$5,285	$744	$382	$1	$218	$0	CWNB
5335	Bad Debt Expense	$6,000	$1,639	$521	$3,839	$0	$0	$0	BDHA
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	CWNB
	Sub-total	*$588,252*	*$487,140*	*$58,010*	*$29,376*	*$68*	*$13,657*	*$0*	
	Sub Total Operating, Maintenance and Biling	*$967,339*	*$780,652*	*$84,948*	*$34,787*	*$51,204*	*$15,748*	*$0*	
	Amortization Expense - Customer Related	$255,316	$203,612	$18,606	$9,536	$22,636	$925	$0	
	Amortization Expense - General Plant assigned to Meters	$70,431	$55,543	$4,900	$1,909	$7,763	$317	$0	
	Admin and General	$693,072	$558,084	$61,201	$25,471	$37,422	$10,895	$0	
	Allocated PILs	$26,166	$20,635	$1,820	$709	$2,884	$118	$0	
	Allocated Debt Return	$236,136	$186,220	$16,427	$6,401	$26,026	$1,064	$0	
	Allocated Equity Return	$262,940	$207,357	$18,291	$7,127	$28,980	$1,185	$0	
	PLCC Adjustment for Line Transformer	$63,419	$58,275	$4,104	$561	$0	$479	$0	
	PLCC Adjustment for Primary Costs	$147,964	$135,887	$9,573	$1,388	$0	$1,116	$0	
	PLCC Adjustment for Secondary Costs	$43,104	$39,956	$2,774	$0	$0	$374	$0	

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	Unmetered Scattered Load	Back-up/Standby Power
Distribution Plant							
CWMC	$ 1,719,942	$ 1,426,864	$ 159,150	$ 133,928	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (226,409)	$ (187,829)	$ (20,950)	$ (17,630)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 1,493,533	$ 1,239,035	$ 138,200	$ 116,298	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (26,391)	$ (21,037)	$ (2,961)	$ (1,521)	$ (4)	$ (867)	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (55,000)	$ (38,095)	$ (4,920)	$ (11,519)	$ (180)	$ (287)	$ -
Sub-total	$ (81,391)	$ (59,133)	$ (7,881)	$ (13,039)	$ (184)	$ (1,154)	$ -
Operation							
CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ 4,701	$ 3,642	$ 256	$ 38	$ 735	$ 30	$ -
Sub-total	$ 4,701	$ 3,642	$ 256	$ 38	$ 735	$ 30	$ -
Maintenance							
1860	$ 48,178	$ 39,968	$ 4,458	$ 3,752	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 166,644	$ 154,202	$ 10,853	$ 1,589	$ -	$ -	$ -
CWNB	$ 411,324	$ 327,884	$ 46,155	$ 23,701	$ 68	$ 13,516	$ -
Sub-total	$ 577,968	$ 482,086	$ 57,008	$ 25,290	$ 68	$ 13,516	$ -
Total Operation, Maintenance and Billing	$ 630,847	$ 525,697	$ 61,722	$ 29,079	$ 802	$ 13,546	$ -
Amortization Expense - Meters	$ 110,147	$ 91,378	$ 10,192	$ 8,577	$ -	$ -	$ -
Allocated PILs	$ 6,959	$ 5,774	$ 644	$ 542	$ -	$ -	$ -
Allocated Debt Return	$ 62,805	$ 52,103	$ 5,811	$ 4,890	$ -	$ -	$ -
Allocated Equity Return	$ 69,933	$ 58,017	$ 6,471	$ 5,446	$ -	$ -	$ -
Total	**$ 799,301**	**$ 673,836**	**$ 76,960**	**$ 35,495**	**$ 618**	**$ 12,393**	**$ -**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load	Back-up/Standby Power
Distribution Plant							
CWMC	$ 1,719,942	$ 1,426,864	$ 159,150	$ 133,928	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (226,409)	$ (187,829)	$ (20,950)	$ (17,630)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 1,493,533	$ 1,239,035	$ 138,200	$ 116,298	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 145,480	$ 120,690	$ 13,462	$ 11,328	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 1,639,014	$ 1,359,726	$ 151,662	$ 127,626	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (26,391)	$ (21,037)	$ (2,961)	$ (1,521)	$ (4)	$ (867)	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (55,000)	$ (38,095)	$ (4,920)	$ (11,519)	$ (180)	$ (287)	$ -
Sub-total	*$ (81,391)*	*$ (59,133)*	*$ (7,881)*	*$ (13,039)*	*$ (184)*	*$ (1,154)*	*$ -*
Operation							
CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ 4,701	$ 3,642	$ 256	$ 38	$ 735	$ 30	$ -
Sub-total	*$ 4,701*	*$ 3,642*	*$ 256*	*$ 38*	*$ 735*	*$ 30*	*$ -*
Maintenance							
1860	$ 48,178	$ 39,968	$ 4,458	$ 3,752	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 166,644	$ 154,202	$ 10,853	$ 1,589	$ -	$ -	$ -
CWNB	$ 411,324	$ 327,884	$ 46,155	$ 23,701	$ 68	$ 13,516	$ -
Sub-total	*$ 577,968*	*$ 482,086*	*$ 57,008*	*$ 25,290*	*$ 68*	*$ 13,516*	*$ -*
Total Operation, Maintenance and Billing	$ 630,847	$ 525,697	$ 61,722	$ 29,079	$ 802	$ 13,546	$ -
Amortization Expense - Meters	$ 110,147	$ 91,378	$ 10,192	$ 8,577	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 20,557	$ 17,054	$ 1,902	$ 1,601	$ -	$ -	$ -
Admin and General	$ 451,535	$ 375,818	$ 44,468	$ 21,291	$ 586	$ 9,372	$ -
Allocated PILs	$ 7,637	$ 6,336	$ 707	$ 595	$ -	$ -	$ -
Allocated Debt Return	$ 68,922	$ 57,178	$ 6,378	$ 5,367	$ -	$ -	$ -
Allocated Equity Return	$ 76,745	$ 63,668	$ 7,101	$ 5,976	$ -	$ -	$ -
Total	**$ 1,285,001**	**$ 1,077,996**	**$ 124,589**	**$ 59,446**	**$ 1,204**	**$ 21,764**	**$ -**

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	Unmetered Scattered Load	Back-up/Standby Power
	Distribution Plant							
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 3,996,825	$ 3,096,784	$ 217,960	$ 31,978	$ 624,571	$ 25,532	$ -
	SNCP	$ 750,787	$ 586,410	$ 41,273	$ -	$ 118,269	$ 4,835	$ -
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 2,180,786	$ 1,690,642	$ 118,992	$ 16,238	$ 340,975	$ 13,939	$ -
	CWCS	$ 465,542	$ 344,669	$ 48,517	$ -	$ 69,514	$ 2,842	$ -
	CWMC	$ 1,719,942	$ 1,426,864	$ 159,150	$ 133,928	$ -	$ -	$ -
	Sub-total	*$ 9,113,882*	*$ 7,145,369*	*$ 585,892*	*$ 182,145*	*$ 1,153,330*	*$ 47,147*	*$ -*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (3,996,839)	$ (3,110,020)	$ (229,927)	$ (43,442)	$ (589,358)	$ (24,092)	$ -
	Customer Related Net Fixed Assets	$ 5,117,042	$ 4,035,349	$ 355,965	$ 138,703	$ 563,971	$ 23,055	$ -
	Allocated General Plant Net Fixed Assets	$ 498,434	$ 393,070	$ 34,673	$ 13,511	$ 54,935	$ 2,246	$ -
	Customer Related NFA Including General Plant	$ 5,615,476	$ 4,428,419	$ 390,638	$ 152,213	$ 618,906	$ 25,300	$ -
	Misc Revenue							
	CWNB	$ (111,741)	$ (89,074)	$ (12,538)	$ (6,439)	$ (18)	$ (3,672)	$ -
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (55,000)	$ (38,095)	$ (4,920)	$ (11,519)	$ (180)	$ (287)	$ -
	Sub-total	*$ (166,741)*	*$ (127,169)*	*$ (17,458)*	*$ (17,957)*	*$ (198)*	*$ (3,958)*	*$ -*
	Operating and Maintenance							
	1815-1855	$ 125,514	$ 97,073	$ 7,244	$ 818	$ 19,578	$ 800	$ -
	1830 & 1835	$ 45,906	$ 35,626	$ 2,507	$ 294	$ 7,185	$ 294	$ -
	1850	$ 27,505	$ 21,323	$ 1,501	$ 205	$ 4,301	$ 176	$ -
	1840 & 1845	$ 9,347	$ 7,247	$ 510	$ 69	$ 1,462	$ 60	$ -
	CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CCA	$ 4,701	$ 3,642	$ 256	$ 38	$ 735	$ 30	$ -
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 12,034	$ 9,339	$ 657	$ 77	$ 1,884	$ 77	$ -
	1835	$ 24,851	$ 19,286	$ 1,357	$ 159	$ 3,890	$ 159	$ -
	1855	$ 81,050	$ 60,006	$ 8,447	$ -	$ 12,102	$ 495	$ -
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1860	$ 48,178	$ 39,968	$ 4,458	$ 3,752	$ -	$ -	$ -
	Sub-total	*$ 379,087*	*$ 293,512*	*$ 26,938*	*$ 5,411*	*$ 51,136*	*$ 2,090*	*$ -*
	Billing and Collection							
	CWNB	$ 415,608	$ 331,299	$ 46,635	$ 23,948	$ 68	$ 13,657	$ -
	CWMR	$ 166,644	$ 154,202	$ 10,853	$ 1,589	$ -	$ -	$ -
	BDHA	$ 6,000	$ 1,639	$ 521	$ 3,839	$ -	$ -	$ -
	Sub-total	*$ 588,252*	*$ 487,140*	*$ 58,010*	*$ 29,376*	*$ 68*	*$ 13,657*	*$ -*
	Sub Total Operating, Maintenance and Biling	*$ 967,339*	*$ 780,652*	*$ 84,948*	*$ 34,787*	*$ 51,204*	*$ 15,748*	*$ -*
	Amortization Expense - Customer Related	$ 255,316	$ 203,612	$ 18,606	$ 9,536	$ 22,636	$ 925	$ -
	Amortization Expense - General Plant assigned to Meters	$ 70,431	$ 55,543	$ 4,900	$ 1,909	$ 7,763	$ 317	$ -
	Admin and General	$ 693,072	$ 558,084	$ 61,201	$ 25,471	$ 37,422	$ 10,895	$ -
	Allocated PILs	$ 26,166	$ 20,635	$ 1,820	$ 709	$ 2,884	$ 118	$ -
	Allocated Debt Return	$ 236,136	$ 186,220	$ 16,427	$ 6,401	$ 26,026	$ 1,064	$ -
	Allocated Equity Return	$ 262,940	$ 207,357	$ 18,291	$ 7,127	$ 28,980	$ 1,185	$ -
	PLCC Adjustment for Line Transformer	$ 63,419	$ 58,275	$ 4,104	$ 561	$ -	$ 479	$ -
	PLCC Adjustment for Primary Costs	$ 147,964	$ 135,887	$ 9,573	$ 1,388	$ -	$ 1,116	$ -
	PLCC Adjustment for Secondary Costs	$ 43,104	$ 39,956	$ 2,774	$ -	$ -	$ 374	$ -
	Total	**$ 2,090,173**	**$ 1,650,814**	**$ 172,285**	**$ 66,035**	**$ 176,715**	**$ 24,324**	**$ -**

Exhibit 8 Rate Design

OVERVIEW

This Exhibit provides the calculation and rationale for Grimsby Power Inc.'s proposed distribution rates, by rate class for the 2012 Test Year, based on the rate design as proposed in this Exhibit.

The Applicant's total 2012 service revenue requirement has been calculated to be $4,583,444. The total revenue offsets of $339,741 will reduce Grimsby Power Inc.'s total service revenue requirement to a net base revenue requirement of $4,243,703. The base revenue requirement is used to determine the proposed distribution rates by rate class and is derived from Grimsby Power Inc.'s 2012 capital and operating forecasts, weather normalized electricity consumption, forecasted customer counts, and regulated return on rate base. The revenue requirements are summarized below in Table 8.1:

Table 8.1 Revenue Requirement

OM&A Expenses	$	2,623,797
Amortization Expenses	$	709,099
Total Distribution Expenses	**$**	**3,332,896**
Add: Regulated Return On Capital	$	1,188,248
Add: PILs	$	62,299
Service Revenue Requirement	**$**	**4,583,444**
Less: Revenue Offsets	-$	339,741
Base Revenue Requirement	$	4,243,703

ALLOCATION OF BASE REVENUE REQUIREMENT

The base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios as outlined in Exhibit 7. Table 8.2 below summarizes the movement of revenue at 2011 rates for the base revenue requirement to the proposed based revenue requirement.

Table 8.2 Existing and Proposed Rate Base Revenue

Customer Class	Distribution Revenue at Existing Rates	Proposed Base Revenue
Residential	2,555,823	3,108,137
GS < 50 kW	392,621	492,337
GS >50	432,269	542,054
Street Lighting	34,428	80,351
USL	15,428	20,824
TOTAL	3,430,927	4,243,703

FIXED/VARIABLE PROPORTION

The purpose of this section is to describe the determination of the fixed and variable proportion by rate class, and the calculation of the proposed fixed and variable distribution rates for the 2012 Test year.

Proposed Fixed Charges

In its November 28, 2008 Report on Application of Cost Allocation for Electricity Distributors, referred to in Exhibit 7 above, the OEB addressed a number of "Other Rate Matters", including the treatment of the fixed rate component (the Monthly Service Charge, or "MSC") of the bill. At page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the 2006 report of the OEB entitled "Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors". Grimsby Power Inc.'s MSCs exceeds that floor amount. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB's Rate Review proceeding (EB-2009-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time.

Consistent with recent Board Decision on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities this Application proposes to maintain the current fixed/variable proportions for all rate classes: Residential, General Service <50kW, General Service >50kW, Street Lighting, and Unmetered Scattered Load.

All other changes in MSCs are due to changes in the total base revenue requirement attributable to each customer class. Table 8.3 below provides the proportions of fixed and variable charges by rate class for the current and proposed fixed and variable charges based on the 2012 Test year load forecast and base revenue requirement.

Table 8.3 Fixed / Variable Charge Analysis

Customer Class	Current Volumetric Split	Current Fixed Charge Spilt	Total
Residential	31.16%	68.84%	100.00%
GS < 50 kW	46.65%	53.35%	100.00%
GS >50	54.08%	45.92%	100.00%
Street Lighting	41.39%	58.61%	100.00%
USL	22.28%	77.72%	100.00%

Table 8.4 to 8.6 below illustrates the fixed and variable base revenue and resulting distribution charges for the 2012 Test Year.

Table 8.4 Summary of Proposed Fixed Distribution Charge

Customer Class	Total Base Revenue Requirement	Fixed Revenue	Fixed Revenue Proportion	2011 Test Year Customers	Proposed Fixed Distribution Charge
Residential	3,123,569	2,150,235	68.84%	9,703	18.47
GS < 50 kW	485,632	259,096	53.35%	683	31.62
GS >50	534,672	245,513	45.92%	100	204.19
Street Lighting	79,108	46,364	58.61%	2,548	1.52
USL	15,428	16,104	104.38%	80	16.78
TOTAL	4,243,703	2,717,312		13,114	

Table 8.5 Fixed Charge Summary

Customer Class	Unit	2011 Rates From OEB Approved Tariff	Fixed Rate - Current Fixed/Variable Revenue Proportions	Fixed Rate Proposed	Customer Unit Cost - Avoided Cost (Floor Fixed Charge from Cost Allocation Model)	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)
Residential	customer/month	15.11	18.47	18.47	5.79	14.18
GS < 50 kW	customer/month	25.56	31.62	31.62	9.39	21.02
GS >50	customer/month	165.08	204.19	204.19	29.52	54.92
Street Lighting	connection/month	0.66	1.52	1.52	0.03	7.52
USL	connection/month	12.78	16.78	16.78	12.91	25.34

Proposed Volumetric Charges

The variable distribution charge is determined based on the allocated variable base revenue requirement. The variable distribution portion of the base revenue requirement is divided by the 2012 Test year charge determinant as applicable for each rate class. (kWh or kW). Table 8.6 below provides the 2012 proposed variable distribution rates before the adjustment for transformation allowance.

Table 8.6 Variable Distribution Charge Calculation

Customer Class	Total Base Revenue Requirement	Variable Revenue	Variable Revenue Proportion	2012 Test Year Volumetric Billing Determinant	Unit	Proposed Variable Distribution Charge
Residential	3,123,569	973,334	31.16%	92,606,843	kWh	0.0105
GS < 50 kW	485,632	226,536	46.65%	18,314,894	kWh	0.0124
GS >50	534,672	289,159	54.08%	188,723	kW	1.5322
Street Lighting	79,108	32,744	41.39%	4,403	kW	7.4364
USL	20,721	4,617	22.28%	355,293	kWh	0.0130
TOTAL	4,243,703	1,526,391		181,732,931		

Transformer Allowance

Currently, Grimsby Power Inc. provides a Transformer Allowance to those customers that own their transformation facilities. Grimsby Power Inc. is proposing to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of the Transformer Allowance expected to be provided to those GS > 50 kW customers that own their transformers is included in the GS > 50 kW volumetric charge. As a result, the proposed volumetric charge of $1.5533 per kW for the GS > 50 kW customer class is increased by $0.1749 per kW to include the amount of the Transformer Allowance in the GS > 50 kW class distribution volumetric rate This means the total proposed distribution volumetric charge for the GS > 50 kW class will be $1.7282.

RETAIL TRANSMISSION SERVICE RATES (RTSR'S)

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 Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "2012_RTSR_Adjustment_Work_Form" and instructions for distributors to complete as part of their 2012 electricity rate applications. Grimsby Power Inc. has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8.7 is reproduced from the Board model and indicates the new RTSR's.

Table 8.7 Final 2012 RTS Rates

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	kWh	$	0.0066	$	0.0054
General Service Less Than 50 kW	kWh	$	0.0061	$	0.0047
General Service 50 to 499 kW	kW	$	2.4546	$	1.9125
General Service 50 to 999 kW - Interval Metered	kW	$	2.4860	$	2.0159
Unmetered Scattered Load	kWh	$	0.0061	$	0.0047
Street Lighting	kW	$	1.8512	$	1.4785

LOSS ADJUSTMENT FACTORS

An explanation of Grimsby Power Inc.'s embedded status is explained in Exhibit 1 under "Explanation of Host and Embedded Utilities". Grimsby Power has not been required to complete any loss studies as a result of previous decisions. Grimsby Power Inc.'s historical losses are less than 5% and as such no studies or direct measures have been taken to produce a reduction in losses.

Total Loss Factor

Grimsby Power Inc. has calculated the total loss factor of 1.0526% to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2006 to 2010. The calculations are summarized in Table 8.8 below.

Table 8.8 Loss Factor Calculations (Board Appendix 2-P)

		Historical Years					5-Year Average
		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	177,010,661	182,668,136	181,594,867	179,620,065	188,943,817	181,967,509
A(2)	"Wholesale" kWh delivered to distributor (lower value)	174,586,963	180,314,717	179,230,963	177,261,932	186,703,093	179,619,534
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	174,586,963	180,314,717	179,230,963	177,261,932	186,703,093	179,619,534
D	"Retail" kWh delivered by distributor	169,025,475	173,068,981	172,075,839	170,620,093	179,605,826	172,879,243
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	169,025,475	173,068,981	172,075,839	170,620,093	179,605,826	172,879,243
G	Loss Factor in Distributor's system = **C / F**	1.03	1.04	1.04	1.04	1.04	1.04
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.013882468	1.013051727	1.013189148	1.013303101	1.012001537	1.013085596
	Total Losses						
I	Total Loss Factor = **G x H**	1.047242497	1.055464331	1.055318796	1.052748607	1.051991586	1.052584218

Supply Facility Loss factor

Grimsby Power Inc. is connected to the IESO controlled grid through Hydro One and Niagara West Transformation Corporation distribution and transmission equipment and as such the supply facility loss factor (the “SFLF”) is equal to 1.0131 or 1.31% as calculated in Table 8.8 above.

LRAM / SSM

On May 31, 2004, the Minister of Energy granted approval to all electricity distributors in Ontario to apply to the OEB for adjustments to their 2005 rates in the amount of the third installment of their incremental market adjusted revenue requirement (MARR). This approval was conditional on a commitment to revenues an equivalent amount in CDM initiatives. In 2005, Grimsby Power Inc.’s CDM Plans under EB-2005-0097 were approved by the OEB.

Grimsby Power Inc. began the first of several successful CDM customer programs in 2005 and successfully transitioned to the Ontario Power Authority (OPA) funded programs in 2009. Between 2005 and 2009, CDM has yielded energy savings and reduced peak demand.

The OEB Guidelines for Electricity Distributor Conservation and Demand Management number EB-2009-0037, issued March 28, 2009, provides guidelines for rate-based applications to recover revenues lost as a result of customer energy conservation, in addition to sharing in gains from CDM programs prior to the completion of the Third Tranche CDM programs. The Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM) are the mechanisms used to recover these losses.

The success of CDM programs is resulting in a reduction in distribution revenue. Grimsby Power Inc. seeks to recover these losses through the LRAM only as part the 2012 Cost of Service rate application.

Grimsby Power Inc. retained the services of Burman Energy Consultants Group (Burman Energy) to ensure the analysis was completed by a seasoned and experienced service provider. In their report, Burman Energy concludes the recoverable total lost revenue from 2005 through 2009 to be $100,715.80.

Grimsby Power Inc. is requesting an LRAM amount of $100,715.80. Supporting details for these amounts are included in the Burman Energy report attached as Appendix 8.1, LRAM Support dated April 20, 2011.

Grimsby Power Inc. is requesting an LRAM rate rider be established to collect the total claim amount which has been allocated to the Residential, General Service < 50kW, and General Service >50kW.

Grimsby Power Inc. seeks to recover the LRAM over a two year period, as a means to mitigate the rate impact on these customer groups. Table 8.9 below provides the calculation of the LRAM rate riders for each rate class.

Table 8.9 Calculation of LRAM / SSM Rate Rider

Rate Class	Amounts LRAM $	Billing Units (2012)	Metrics	Rate Riders LRAM $/unit (kWh or kW)	Rate Riders SSM $/unit (kWh or kW)	Rate Riders Total $/unit (kWh or kW)	Two Year Rate Rider Total $/unit (kWh or kW)	Three Year Rate Rider Total $/unit (kWh or kW)	Number of Years to Use (2 or 3) 2	Rate Rider to Use Total $/unit (kWh or kW)
Residential	59,700.41	92,606,843	kWh	0.0006	0.0000	0.0006	0.0003	0.0002		0.0003
GS < 50 kW	6,266.69	18,314,894	kWh	0.0003	0.0000	0.0003	0.0002	0.0001		0.0002
GS >50	34,748.71	188,723	kW	0.1841	0.0000	0.1841	0.0921	0.0614		0.0921
Street Lighting		4,403	kW	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
USL		355,293	kWh	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000
Total	100,715.81									

Specific Service Charges

Grimsby Power Inc. is not seeking to change the current Board Approved Specific Service Charges. Specific charges are noted in Exhibit 1.

EXISTING AND PROPOSED RATE CLASSES

Grimsby Power Inc. is not proposing to change its existing rate structure except that it is proposing to eliminate the Standby Power Service Classification.

Residential (Existing):

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separated metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex, or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less < 50kW (Existing):

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.

General Service > 50kW (Existing):

This classification applies to a non residential account whose average monthly maximum demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW.

Standby Power Service Classification (Existing):

This classification applies to an account that has load displacement generation and requires Grimsby Power Inc. to provide back-up service.

Unmetered Scattered Load (Existing):

This classification refers to an account taking electricity at 750 volts or less whose monthly average 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, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption.

Street Lighting Service (Existing):

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

MicroFIT Generator Service Classification (Existing):

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's MicroFIT program.

EXISTING RATE SCHEDULE

Grimsby Power Inc. existing rate schedule, effective May 1, 2011 as approved by the OEB is attached as Appendix 8.2.

SCHEDULE OF PROPOSED RATES AND CHARGES

Grimsby Power Inc. is proposing the rates and charges as detailed in Table 8.10 below.

Table 8.10 Rates & Charges by Service Classifications

Residential		
Monthly Service Charge	$	18.47
Distribution Volumetric Rate	$/kwh	0.0105
Low Voltage Rider	$/kwh	0.0007
LRAM and SSM Rate Rider	$/kwh	0.0003
Smart Meter Rate Rider	$	4.8458
Deferral and Variance Account Rider	$/kwh	(0.0014)
Retail Transmission Rate - Network	$/kwh	0.0066
Retail Transmission Rate – Connection	$/kwh	0.0054
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.0250
General Service < 50 kW		
Monthly Service Charge	$	31.62
Distribution Volumetric Rate	$/kwh	0.0124
Low Voltage Rider	$/kwh	0.0006
LRAM and SSM Rate Rider	$/kwh	0.0002

Smart Meter Rate Rider	$	4.8458
Deferral and Variance Account Rider	$/kwh	(0.0013)
Retail Transmission Rate - Network	$/kwh	0.0061
Retail Transmission Rate – Connection	$/kwh	0.0047
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.0250
General Service > 50 kW		
Monthly Service Charge	$	204.19
Distribution Volumetric Rate	$/kW	1.7071
Low Voltage Rider	$/kW	0.2603
LRAM and SSM Rate Rider	$/kW	0.0921
Smart Meter Rate Rider	$	4.8458
Deferral and Variance Account Rider	$/kW	(0.4621)
Retail Transmission Rate - Network	$/kW	2.4546
Retail Transmission Rate – Connection	$/kW	1.9125
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.0250

Street Lighting		
Monthly Service Charge	per month	1.52
Distribution Volumetric Rate	$/kW	7.4364
Low Voltage Rider	$/kW	0.2012
LRAM and SSM Rate Rider	$/kW	0.0000
Deferral and Variance Account Rider	$/kW	(1.0081)
Retail Transmission Rate - Network	$/kW	1.8512
Retail Transmission Rate – Connection	$/kW	1.4785
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.2500
Unmetered Scattered Load		
Monthly Service Charge	per month	16.78
Distribution Volumetric Rate	$/kwh	0.0130
Low Voltage Rider	$/kwh	0.0006
LRAM and SSM Rate Rider	$/kwh	0.0000
Deferral and Variance Account Rider	$/kwh	(0.0015)
Retail Transmission Rate - Network	$/kwh	0.0061

Retail Transmission Rate – Connection	$/kwh	0.0047
Wholesale Market Service Rate	$/kwh	0.0065
Rural Rate Protection Charge	$/kwh	0.0013
Standard Supply Service	$	0.2500

Specific Service Charges
The specific service charges are not being changed. See Appendix 8.2.

Retail Service Charges
The retail service charges are not being changed. See Appendix 8.2.

Wholesale Market Service Rate
Grimsby Power Inc. is not proposing to change the Wholesale Market Service Rate.

Loss Factors
Grimsby Power Inc. is proposing the loss factors as indicated in Table 8.11 below.

Table 8.11 Loss Factors

Loss Factors	
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0526
Total Loss Factor - Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0421
Total Loss Factor - Primary Metered Customer > 5,000 kW	N/A

RECONCILIATION OF RATE CLASS REVENUE

The following Table 8.12 provides the reconciliation required.

Table 8.12 Revenue Reconciliation (Board Appendix 2-U)

Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Average	Test Year Consumption kWh	kW	Proposed Rates Monthly Service Charge	Volumetric kWh	Volumetric kW	Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
Residential	Customers	9,703	92,606,843		$ 18.47	$ 0.0105		$ 3,123,569	$ 3,123,569		$ 3,123,569	$ -
GS < 50 kW	Customers	683	18,314,894		$ 31.62	$ 0.0124		$ 485,632	$ 485,632		$ 485,632	$ -
GS > 50 to 4,999 kW	Customers	100	68,877,755	188,723	$ 204.19		$ 1.7071	$ 567,672	$ 534,672	$ 33,000	$ 567,672	$ -
Large Use								$ -	$ -		$ -	$ -
Streetlighting	Connections	2,548	1,578,145	4,403	$ 1.52		$ 7.4364	$ 79,108	$ 79,108		$ 79,108	$ -
Sentinel Lighting		-						$ -			$ -	$ -
Unmetered Scattered Load	Connections	80	355,293		$ 16.78	$ 0.0130		$ 20,721	$ 20,721		$ 20,721	$ -
Standby Power		-						$ -	$ -		$ -	$ -
Embedded Distributor		-						$ -	$ -		$ -	$ -
etc.		-						$ -			$ -	$ -
		-						$ -			$ -	$ -
		-						$ -			$ -	$ -
		-						$ -			$ -	$ -
Total		13,114	181,732,931	193,126				$ 4,276,703	$ 4,243,703	$ 33,000	$ 4,276,703	$ -

RATE AND BILL IMPACTS

Appendix 8.3 to this Exhibit presents the results of the assessment of customer total bill impacts by customer rate class based on the Boards Appendix 2-V templates. These impacts are based on the following:

- Current applicable approved May 1, 2011 rates
- Proposed 2012 Smart Meter Disposition Rider
- Proposed 2012 Stranded Meter Disposition Rate Rider
- Proposed Low Voltage Service Rates
- Proposed 2012 Deferral/Variance Account Rate Rider
- Proposed 2012 LRAM & SSM Rate Rider
- Proposed 2012 RTSR Rates
- Proposed revised Loss Factors
- 13% HST
- Electricity energy rates for Residential, General Service < 50 kW are the rates effective May 1, 2011 for Rate Protection Plan (RPP) customers.

RATE MITIGATION

Grimsby Power Inc. has evaluated the need for a mitigation plan based on the percentage increases in total bill impact for the following typical customers:

- Residential – 800kWh
- GS<50 – 2,000kWh
- GS>50 – 30,000kWh & 100kW

Referring to the rate impact calculations shown below the total bill impacts for the above typical customers is:

- Residential – 800kWh 7.72%
- GS<50 – 2,000kWh 5.57%
- GS>50 – 30,000kWh & 100kW 2.49%

These increases are less than the 10% threshold referenced in the filing requirements and therefore, no mitigation plan is necessary.

Appendix 8.1 Burman Energy LRAM Support for Grimsby Power Inc.

98 Archibald Road, Kettleby, Ont. L0G 1J0 ● Phone: 1-877-662-5489 ● Fax: 905-939-4606 ● Email: info@burmanenergy.ca ● www.burmanenergy.ca

Grimsby Power Incorporated

LRAM Support

April 20, 2011

Prepared by: Bart Burman, MBA, BA.Sc. P.Eng., President

Table of Contents

1. Introduction

With success in its CDM activities, Grimsby Power Incorporated (Grimsby Power) has lost revenues that need to be addressed as part of its 2011 rates submission to the Ontario Energy Board (OEB). This process will ensure that future CDM investments are sustainable in the long term by becoming a standard element in future rate filings.

The Ontario Energy Board (OEB) introduced a process outlined in the March 28, 2008 Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037) ("CDM Guidelines") for rate-based applications to recover revenues lost to customer energy conservation, and to share in gains from effective CDM programs prior to the completion of Third Tranche CDM programs. The mechanism developed by the OEB to calculate lost revenue for savings is the Lost Revenue Adjustment Mechanism (LRAM).

The application for LRAM compensation is part of Grimsby Power's 2011 IRM filing and is based on its 2005 to 2009 inclusive CDM results.

2. Required

Grimsby Power requested that Burman Energy Consultants Group Inc. (Burman Energy) review the LDC's preliminary LRAM and supporting information and assist in producing finalized calculations and report suitable to support an LRAM claim as part of its 2011 rates submission. In completing the scope of work related to LRAM, Burman Energy committed to:

1. Review LRAM Total Resource Cost (TRC) calculations and underlying data prepared by Grimsby Power for annual year end CDM reports, and assess compliance with the CDM Guidelines, identifying variances and reconciliations.
2. Prepare and finalize LRAM and assumptions consistent with CDM Guidelines and suitable for inclusion in Grimsby Power's 2011 IRM/rates application, with supporting details.
3. Produce a report, recommendations, and supporting Attachments related to LRAM and SSM assessments/findings.

In performing the above tasks, Burman Energy's involvement is intended to constitute a third party review as specified in the OEB's CDM Guidelines.

3. About LRAM

The OEB issued GUIDELINES FOR ELECTRICITY DISTRIBUTOR CONSERVATION AND DEMAND MANAGEMENT, EB-2008-0037 were applied to the preparation of this LRAM application.

LRAM was calculated as the product of the demand/energy savings by customer class and the Board-approved variable distribution charge appropriate to each respective class (net of

Regulatory Asset Recovery rate riders). Both Third Tranche and OPA sponsored program kW/kWhs savings were deemed eligible for consideration of the LRAM claim.

4. Methodology

To optimize the calculation of LRAM, Burman Energy:

1. Reviewed existing LRAM CDM Guidelines and precedents set through LDC submissions to the OEB, to identify the most prudent course for Grimsby Power's LRAM application.

2. Sought counsel within OEB staff to validate assumptions and processes to complete LRAM submission consistent with other LDC submissions. Validation by each specific technology employed is included in the accompanying documentation.

3. Reviewed Grimsby Power's CDM program results and TRC calculations, verified assumptions and calculations, identified variances with reported values, and recommended adjustments as appropriate to maintain consistency with the CDM Guidelines. Actual program results were provided by Grimsby Power, including CDM Annual Reports, OPA program results reports, and supplemental information relevant to LRAM calculations.

4. Prepared report and recommendations related to LRAM calculations consistent with OEB CDM Guidelines which are in the accompanying documentation.

5. Results

A review of LDC CDM programs with Grimsby Power verified that documentation exists to support participation levels associated with the LRAM.

The OPA has validated the results allocated to Grimsby Power for OPA sponsored programs through Third Party Verification. Program results were confirmed to begin the year after program implementation.

The timing of results used in LRAM calculations for OPA sponsored programs are contained in the accompanying documentation under OPA Conservation Results, issued November 10, 2009.

The accompanying table below sets out the calculated amounts for LRAM for Grimsby Power's OPA CDM programming. The calculation of the results, by program and customer class as applicable, are explained in the text below, and detailed in the appended attachment.

Rate Class

	LRAM $
-	
OPA Programs	
RESIDENTIAL	$59,700.41
GENERAL SERVICE <50KW	$6,266.69
GENERAL SERVICE >50KW	$34,748.71
	$100,715.80

6. Determination of LRAM Amount

LRAM amounts were identified by rate class consistent with the CDM Guidelines for programs that impacted revenues from 2006 to 2009, for OPA CDM programs. No forecast or other adjustment for the effects of CDM programs was made to the load quantities used in the preparation of Grimsby Power's rate cases in prior years. The entire actual load reduction achieved by the eligible OPA CDM programs is subject to LRAM treatment. All results are net of free ridership. For all programs/projects, the most recently published OPA assumptions and measures list were used in LRAM calculations in accordance with OEB's direction letter, Conservation and Demand Management ("CDM") Input Assumptions Board File No.: EB-2008-0352, January 27, 2009 and consistent with recent Decision and Order EB-2009-0192 for Horizon Utilities Corporation that directed LRAM calculations use the most current available input assumptions for all CDM programs.

The sum of all program LRAM calculations, including OPA sponsored programs is $100,715.80.

Attachment A summarizes load impacts by class and program. Attachment B (Foregone Revenue By Class and Program) summarizes the CDM load impacts by program and rate class and the resultant revenue impacts.

7. Allocation and Manner of Recovery for LRAM Amounts

The LRAM amounts arising from CDM programs in each respective rate class are allocated to that class for recovery. LRAM rate riders should be combined and expressed as a single rate rider for each class, based on approaches taken by other LDCs

8. Recommendations

Burman Energy recommends the following:

1. LRAM amounts arising from CDM programs in each rate class be allocated to that class for recovery.

Appendix 8.2 Grimsby Power Inc. OEB Approved Rate Schedule

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0129

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

AND IN THE MATTER OF an application by Grimsby Power Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2011.

BEFORE: Karen Taylor
Presiding Member

Paula Conboy
Member

DECISION AND ORDER

Introduction

Grimsby Power Inc. ("Grimsby Power"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on November 26, 2010, under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Grimsby Power charges for electricity distribution, to be effective May 1, 2011.

Grimsby Power is one of 80 electricity distributors in Ontario regulated by the Board. Grimsby Power is one of the electricity distributors that will have its rates adjusted for 2011 on the basis of the 2nd Generation Incentive Rate Mechanism ("IRM") process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2011 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On July 9, 2010 the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the Filing Requirements for IRM applications based on the policies in the Report.

Notice of Grimsby Power's rate application was given through newspaper publication in Grimsby Power's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment and no intervenor requests were received. Board staff participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Changes in the Federal and Provincial Income Tax Rates;
- Smart Meter Funding Adder;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Accounts; and
- Late Payment Penalty Litigation Costs.

Price Cap Index Adjustment

Grimsby Power's rate application was filed on the basis of the Filing Requirements. In fixing new distribution rates and charges for Grimsby Power, the Board has applied the policies described in the Filing Requirements and the Report.

As outlined in the Reports, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2010 data published by Statistics Canada, the Board has established the price escalator to be 1.3%. The resulting price cap index adjustment is therefore 0.3%. The rate model reflects this price cap index adjustment. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.

The price cap index adjustment will not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charge; and
- Retail Service Charges.

Changes in the Federal and Provincial Income Tax Rates

In 2011, the maximum income tax rate is 28.25%, the minimum rate for those distributors eligible for both the federal and Ontario small business deduction is 15.50%, and the blended tax rate varies for certain distributors that are only eligible for the Ontario small business deduction. The model provided to distributors calculates the amount of change caused by the tax rate reductions and adjusts distribution rates by 100% of the total change from those taxes included in the most recent cost of service base distribution rates.

The Board finds that a 100% flow through of the impact of changes from the tax level reflected in the Board-approved base rates to the currently known legislated tax level for 2011 is appropriate within the framework of 2nd Generation IRM and shall be effected by means of an adjustment to the Monthly Service Charge and the Volumetric Distribution Charge.

Smart Meter Funding Adder

On October 22, 2008 the Board issued the *Guideline for Smart Meter Funding and Cost Recovery* which sets out the Board's filing requirements in relation to the funding and recovery of costs associated with smart meter activities conducted by electricity distributors.

Grimsby Power requested to change its smart meter funding adder ("SMFA") from $1.00 to $1.99 per metered customer per month.

The Board notes that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board also observes that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, not fully fund prior capital investment. Such treatment increases the risk, absent a prudence review, of over recovery. The Board is not saying that prudently incurred costs are not recoverable; it is stating that a determination of full recovery will be made as part of an application for a prudence review.

Since the deployment of smart meters on a province-wide basis is now nearing completion, and for the reasons noted earlier, the Board expects distributors to file for a final prudence review at the earliest possible opportunity following the availability of audited costs. For those distributors that are scheduled to file a cost-of-service application for 2012 distribution rates, the Board expects that they will apply for the disposition of smart meter costs and subsequent inclusion in rate base. For those distributors that are scheduled to remain on IRM, the Board expects these distributors to file an application with the Board seeking final approval for smart meter related costs. In the interim, the Board will approve a SMFA of $1.99 per metered customer per month from May 1, 2011 to April 30, 2012. This SMFA adder will be reflected in the Tariff of Rates and Charges, and will cease on April 30, 2012. Grimsby Power's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall be continued.

The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Grimsby Power applies for the recovery of these costs on a final basis, if applicable.

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"). Variance 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., variance accounts 1584 and 1586).

On July 8, 2010 the Board issued revision 2.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2011. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributor's specific RTSRs, Board staff provided a filing module. On January 18, 2011, the Board issued its Rate Order for Hydro One Transmission (EB-2010-0002) which adjusted the UTRs effective January 1, 2011. The new UTRs are shown in the following table:

Uniform Transmission Rates	**kW Monthly Rates**		**Change**
	Jan 1, 2010	**Jan 1, 2011**	
Network Service Rate	$2.97	$3.22	+8.4%
Connection Service Rates			
Line Connection Service Rate	$0.73	$0.79	
Transformation Connection Service Rate	$1.71	$1.77	
			+4.9%

The Board has adjusted each distributor's rate application model to incorporate these changes.

Based on the filing module provided by Board staff and the new UTRs effective January 1, 2011 noted in the table above, the Board approves the changes to the RSTRs calculated in the filing module.

Review and Disposition of Group 1 Deferral and Variance Accounts

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Grimsby Power's Group 1 account balances did not exceed the preset disposition threshold referenced above. The Board therefore finds that no disposition is required at this time.

Late Payment Penalty Litigation Costs

In its application, Grimsby Power requested the recovery of a one time expense of $23,236.06 the late payment penalty ("LPP") costs and damages resulting from a court settlement that addressed litigation against many of the former municipal electricity utilities in Ontario.

On October 29, 2010 the Board commenced a generic proceeding on its own motion to determine whether Affected Electricity Distributors[1], including Grimsby Power, should be allowed to recover from their ratepayers the costs and damages incurred as a result of the Minutes of Settlement approved on April 21, 2010 by the Honourable Mr. Justice Cumming of the Ontario Superior Court of Justice (Court File No. 94-CQ-r0878) and as amended by addenda dated July 7, 2010 and July 8, 2010 (the "Minutes of Settlement") in the late payment penalty class action and if so, the form and timing of such recovery. This proceeding was assigned file No. EB-2010-0295.

[1] As defined in the Board's Decision and Order EB-2010-0295

On February 22, 2011, the Board issued its Decision and Order and determined that it is appropriate for the Affected Electricity Distributors to be eligible to recover the costs and damages associated with the LPP class action in rates. The decision set out a listing of each Affected Electricity Distributor and their share of the class action costs that is approved for recovery. The Board also directed Affected Electricity Distributors such as Grimsby Power to file with the Board detailed calculations including supporting documentation, outlining the derivation of the rate riders based on the methodology outlined in the EB-2010-0295 Decision and Order. The Board noted that the rate riders submitted would be verified in each Affected Electricity Distributor's IRM or cost of service application, as applicable. Grimsby Power elected to recover the amount approved in the EB-2010-0295 proceeding and accordingly filed the associated rate riders.

The Board has reviewed Grimsby Power's proposed rate riders and approves them as filed.

Rate Model

With this Decision, the Board is providing Grimsby Power with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2010 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Grimsby Power's new distribution rates shall be effective May 1, 2011.

2. Grimsby Power shall review the draft Tariff of Rates and Charges set out in Appendix A. Grimsby Power shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information, within seven (7) calendar days of the date of this Decision and Order.

3. If the Board does not receive a submission from Grimsby Power to the effect that inaccuracies were found or information was missing pursuant to item 2 of this

Decision and Order, the draft Tariff of Rates and Charges set out in Appendix A of this order will become final, except for the stand by rates which remain interim, effective May 1, 2011, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2011. Grimsby Power shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. If the Board receives a submission from Grimsby Power to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the Board will consider the submission of Grimsby Power and will issue a final Tariff of Rates and Charges.

5. Grimsby Power shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2010-0129,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

DATED at Toronto, April 21, 2011

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2010-0129

DATED: April 21, 2011

Grimsby Power Incorporated
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-2010-0129

RESIDENTIAL SERVICE CLASSIFICATION

This class refers to the supply of electricity to residential customers residing in detached or semi-detached dwelling units, as defined in the local zoning by-law. **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 Grimsby 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. 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, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.11
Smart Meter Funding Adder – effective until April 30, 2012	$	1.99
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.15
Distribution Volumetric Rate	$/kWh	0.0086
Low Voltage Service Rate	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

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

Grimsby Power Incorporated
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-2010-0129

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non-residential customer that is identified by the billing system as registering under 50 kW on a demand meter in any one month of the year. 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.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	25.56
Smart Meter Funding Adder – effective until April 30, 2012	$	1.99
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.34
Distribution Volumetric Rate	$/kWh	0.0100
Low Voltage Service Rate	$/kWh	0.0006
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043

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

Grimsby Power Incorporated
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0129

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non-residential customer that is identified by the billing system as registering equal to or over 50 kW on a demand meter in any one month of the year. 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.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	165.08
Smart Meter Funding Adder – effective until April 30, 2012	$	1.99
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	2.73
Distribution Volumetric Rate	$/kW	1.4136
Low Voltage Service Rate	$/kW	0.2877
Retail Transmission Rate – Network Service Rate	$/kW	2.1814
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7374
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.2093
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8313

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

Grimsby Power Incorporated
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0129

STANDBY POWER SERVICE CLASSIFICATION

This classification applies to an account that has load displacement generation and requires Grimsby Power to provide back-up service. The same rates as the General Service 50kW to 4,999kW are used, except that the billing determinant is based on the name plate rating of the transformer to reflect the fact that Grimsby Power maintains the potential from its system for the desired maximum load. Further servicing details are available in the distributor's Conditions of Service.

Grimsby Power Incorporated
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0129

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to electricity consumption that is not metered and is billed based on estimated usage. Such connections include street lighting equipment not owned by or operated for a municipality or the Province of Ontario, traffic signals and other small services etc. 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, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	12.78
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.04
Distribution Volumetric Rate	$/kWh	0.0099
Low Voltage Service Rate	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043

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

Grimsby Power Incorporated
TARIFF OF RATES AND CHARGES
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EB-2010-0129

STREET LIGHTING SERVICE CLASSIFICATION

All services to street lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street lighting Service. 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, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.66
Rate Rider for Recovery of Late Payment Penalty Litigation Costs – effective until April 30, 2012	$	0.01
Distribution Volumetric Rate	$/kW	3.2363
Low Voltage Service Rate	$/kW	0.2194
Retail Transmission Rate – Network Service Rate	$/kW	1.6452
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3431

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

Grimsby Power Incorporated
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0129

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, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

Grimsby Power Incorporated
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2011

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EB-2010-0129

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, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for Previous Billing	$	15.00
Easement Letter	$	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
Interval Meter Interrogation	$	20.00
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 Charges at Meter – During Regular Hours	$	65.00
Disconnect/Reconnect Charges at Meter – After Regular Hours	$	185.00
Disconnect/Reconnect Charges 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
Install/Remove Load Control Device – During Regular Hours	$	65.00
Install/Remove Load Control Device – After Regular Hours	$	185.00
Temporary Service Install & Remove – Overhead – No Transformer	$	500.00
Temporary Service Install & Remove – Underground – No Transformer	$	300.00
Temporary Service Install & Remove – Overhead – with Transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Grimsby Power Incorporated
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-2010-0129

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, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

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	1.0502
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0397
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Appendix 8.3 Rate and Bill Impacts

Residential – 100kWh:

Customer Class: **Residential**

Consumption 100 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $	Impact % Change
Monthly Service Charge	Monthly	$ 15.1100	1	$ 15.11	$ 18.4700	1	$ 18.47	$ 3.36	22.24%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	100	$ 0.86	$ 0.0105	100	$ 1.05	$ 0.19	22.09%
Low Voltage Rate Adder	per kWh	$ 0.0007	100	$ 0.07	$ 0.0007	100	$ 0.07	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0003	100	$ 0.03	$ 0.03	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0014	100	-$ 0.14	-$ 0.14	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 18.03**			**$ 24.33**	**$ 6.30**	**34.94%**
RTSR - Network	per kWh	$ 0.0059	105.02	$ 0.62	$ 0.0066	105.255	$ 0.69	$ 0.08	12.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	105.02	$ 0.51	$ 0.0054	105.255	$ 0.57	$ 0.05	10.45%
Sub-Total B - Delivery (including Sub-Total A)				**$ 19.16**			**$ 25.59**	**$ 6.43**	**33.54%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	105.02	$ 0.68	$ 0.0065	105.255	$ 0.68	$ 0.00	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	105.02	$ 0.74	$ 0.0070	105.255	$ 0.74	$ 0.00	0.22%
Energy	per kWh	$ 0.0680	105.02	$ 7.14	$ 0.0680	105.255	$ 7.16	$ 0.02	0.22%
Total Bill (before Taxes)				**$ 27.72**			**$ 34.17**	**$ 6.45**	**23.26%**
HST		13%		$ 3.60	13%		$ 4.44	$ 0.84	23.26%
Total Bill (including Sub-total B)				**$ 31.33**			**$ 38.61**	**$ 7.28**	**23.24%**
Ontario Clean Energy Benefit [1]				**-$ 3.13**			**-$ 3.86**	**-$ 0.73**	**23.32%**
Total Bill (including OCEB)				**$ 28.20**			**$ 34.75**	**$ 6.55**	**23.23%**
Loss Factor (%)		5.02%			5.26%				

Residential –250kWh:

Customer Class: **Residential**

Consumption **250** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 15.1100	1	$ 15.11	$ 18.4700	1	$ 18.47	$ 3.36	22.24%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	250	$ 2.15	$ 0.0105	250	$ 2.63	$ 0.48	22.09%
Low Voltage Rate Adder	per kWh	$ 0.0007	250	$ 0.18	$ 0.0007	250	$ 0.18	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0003	250	$ 0.08	$ 0.08	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0014	250	-$ 0.34	-$ 0.34	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 19.43**			**$ 25.85**	**$ 6.42**	**33.07%**
RTSR - Network	per kWh	$ 0.0059	262.55	$ 1.55	$ 0.0066	263.138	$ 1.74	$ 0.19	12.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	262.55	$ 1.29	$ 0.0054	263.138	$ 1.42	$ 0.13	10.45%
Sub-Total B - Delivery (including Sub-Total A)				**$ 22.26**			**$ 29.01**	**$ 6.75**	**30.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	262.55	$ 1.71	$ 0.0065	263.138	$ 1.71	$ 0.00	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	262.55	$ 1.84	$ 0.0070	263.138	$ 1.84	$ 0.00	0.22%
Energy	per kWh	$ 0.0680	262.55	$ 17.85	$ 0.0680	263.138	$ 17.89	$ 0.04	0.22%
Total Bill (before Taxes)				**$ 43.66**			**$ 50.45**	**$ 6.79**	**15.56%**
HST		13%		$ 5.68	13%		$ 6.56	$ 0.88	15.56%
Total Bill (including Sub-total B)				**$ 49.33**			**$ 57.01**	**$ 7.68**	**15.57%**
Ontario Clean Energy Benefit [1]				**-$ 4.93**			**-$ 5.70**	**-$ 0.77**	**15.62%**
Total Bill (including OCEB)				**$ 44.40**			**$ 51.31**	**$ 6.91**	**15.56%**
Loss Factor (%)		5.02%			5.26%				

Residential –500kWh:

Customer Class: **Residential**

Consumption **500** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 15.1100	1	$ 15.11	$ 18.4700	1	$ 18.47	$ 3.36	22.24%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	500	$ 4.30	$ 0.0105	500	$ 5.25	$ 0.95	22.09%
Low Voltage Rate Adder	per kWh	$ 0.0007	500	$ 0.35	$ 0.0007	500	$ 0.35	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0003	500	$ 0.15	$ 0.15	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0014	500	-$ 0.68	-$ 0.68	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 21.75**			**$ 28.38**	**$ 6.63**	**30.50%**
RTSR - Network	per kWh	$ 0.0059	525.1	$ 3.10	$ 0.0066	526.277	$ 3.47	$ 0.38	12.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	525.1	$ 2.57	$ 0.0054	526.277	$ 2.84	$ 0.27	10.45%
Sub-Total B - Delivery (including Sub-Total A)				**$ 27.42**			**$ 34.70**	**$ 7.28**	**26.54%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	525.1	$ 3.41	$ 0.0065	526.277	$ 3.42	$ 0.01	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	525.1	$ 3.68	$ 0.0070	526.277	$ 3.68	$ 0.01	0.22%
Energy	per kWh	$ 0.0680	525.1	$ 35.71	$ 0.0680	526.277	$ 35.79	$ 0.08	0.22%
Total Bill (before Taxes)				**$ 70.22**			**$ 77.59**	**$ 7.37**	**10.50%**
HST		13%		$ 9.13	13%		$ 10.09	$ 0.96	10.50%
Total Bill (including Sub-total B)				**$ 79.34**			**$ 87.68**	**$ 8.34**	**10.51%**
Ontario Clean Energy Benefit [1]				**-$ 7.93**			**-$ 8.77**	**-$ 0.84**	**10.59%**
Total Bill (including OCEB)				**$ 71.41**			**$ 78.91**	**$ 7.50**	**10.50%**

Loss Factor (%) 5.02% (current) 5.26% (proposed)

Residential –800kWh:

Customer Class: **Residential**

Consumption **800** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 15.1100	1	$ 15.11	$ 18.4700	1	$ 18.47	$ 3.36	22.24%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	800	$ 6.88	$ 0.0105	800	$ 8.40	$ 1.52	22.09%
Low Voltage Rate Adder	per kWh	$ 0.0007	800	$ 0.56	$ 0.0007	800	$ 0.56	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0003	800	$ 0.24	$ 0.24	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0014	800	-$ 1.09	-$ 1.09	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 24.54**			**$ 31.42**	**$ 6.88**	**28.05%**
RTSR - Network	per kWh	$ 0.0059	840.16	$ 4.96	$ 0.0066	842.043	$ 5.56	$ 0.60	12.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	840.16	$ 4.12	$ 0.0054	842.043	$ 4.55	$ 0.43	10.45%
Sub-Total B - Delivery (including Sub-Total A)				**$ 33.61**			**$ 41.53**	**$ 7.91**	**23.55%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	840.16	$ 5.46	$ 0.0065	842.043	$ 5.47	$ 0.01	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge	per kWh			$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	840.16	$ 5.88	$ 0.0070	842.043	$ 5.89	$ 0.01	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	240.16	$ 18.97	$ 0.0790	242.043	$ 19.12	$ 0.15	0.78%
Total Bill (before Taxes)				**$ 104.73**			**$ 112.82**	**$ 8.09**	**7.72%**
HST		13%		$ 13.61	13%		$ 14.67	$ 1.05	7.72%
Total Bill (including Sub-total B)				**$ 118.34**			**$ 127.48**	**$ 9.14**	**7.72%**
Ontario Clean Energy Benefit [1]				**-$ 11.83**			**-$ 12.75**	**-$ 0.92**	**7.78%**
Total Bill (including OCEB)				**$ 106.51**			**$ 114.73**	**$ 8.22**	**7.72%**

	Current	Proposed
Loss Factor (%)	5.02%	5.26%

Residential –1000kWh:

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 $	Impact % Change
Monthly Service Charge	Monthly	$ 15.1100	1	$ 15.11	$ 18.4700	1	$ 18.47	$ 3.36	22.24%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	1000	$ 8.60	$ 0.0105	1000	$ 10.50	$ 1.90	22.09%
Low Voltage Rate Adder	per kWh	$ 0.0007	1000	$ 0.70	$ 0.0007	1000	$ 0.70	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0003	1000	$ 0.30	$ 0.30	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0014	1000	-$ 1.37	-$ 1.37	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 26.40**			**$ 33.45**	**$ 7.05**	**26.71%**
RTSR - Network	per kWh	$ 0.0059	1050.2	$ 6.20	$ 0.0066	1052.55	$ 6.95	$ 0.75	12.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	1050.2	$ 5.15	$ 0.0054	1052.55	$ 5.68	$ 0.54	10.45%
Sub-Total B - Delivery (including Sub-Total A)				**$ 37.74**			**$ 46.08**	**$ 8.34**	**22.09%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	1050.2	$ 6.83	$ 0.0065	1052.55	$ 6.84	$ 0.02	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge	per kWh			$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1050.2	$ 7.35	$ 0.0070	1052.55	$ 7.37	$ 0.02	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	450.2	$ 35.57	$ 0.0790	452.553	$ 35.75	$ 0.19	0.52%
Total Bill (before Taxes)				**$ 128.29**			**$ 136.84**	**$ 8.56**	**6.67%**
HST		13%		$ 16.68	13%		$ 17.79	$ 1.11	6.67%
Total Bill (including Sub-total B)				**$ 144.96**			**$ 154.63**	**$ 9.67**	**6.67%**
Ontario Clean Energy Benefit [1]				**-$ 14.50**			**-$ 15.46**	**-$ 0.96**	**6.62%**
Total Bill (including OCEB)				**$ 130.46**			**$ 139.17**	**$ 8.71**	**6.68%**
Loss Factor (%)		5.02%			5.26%				

Residential –1500kWh:

Customer Class: **Residential**

Consumption **1500** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 15.1100	1	$ 15.11	$ 18.4700	1	$ 18.47	$ 3.36	22.24%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	1500	$ 12.90	$ 0.0105	1500	$ 15.75	$ 2.85	22.09%
Low Voltage Rate Adder	per kWh	$ 0.0007	1500	$ 1.05	$ 0.0007	1500	$ 1.05	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0003	1500	$ 0.45	$ 0.45	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0014	1500	-$ 2.05	-$ 2.05	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 31.05**			**$ 38.52**	**$ 7.47**	**24.05%**
RTSR - Network	per kWh	$ 0.0059	1575.3	$ 9.29	$ 0.0066	1578.83	$ 10.42	$ 1.13	12.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	1575.3	$ 7.72	$ 0.0054	1578.83	$ 8.53	$ 0.81	10.45%
Sub-Total B - Delivery (including Sub-Total A)				**$ 48.06**			**$ 57.46**	**$ 9.40**	**19.56%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	1575.3	$ 10.24	$ 0.0065	1578.83	$ 10.26	$ 0.02	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge	per kWh			$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1575.3	$ 11.03	$ 0.0070	1578.83	$ 11.05	$ 0.02	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	975.3	$ 77.05	$ 0.0790	978.83	$ 77.33	$ 0.28	0.36%
Total Bill (before Taxes)				**$ 187.18**			**$ 196.91**	**$ 9.73**	**5.20%**
HST		13%		$ 24.33	13%		$ 25.60	$ 1.26	5.20%
Total Bill (including Sub-total B)				**$ 211.51**			**$ 222.50**	**$ 10.99**	**5.20%**
Ontario Clean Energy Benefit 1				**-$ 21.15**			**-$ 22.25**	**-$ 1.10**	**5.20%**
Total Bill (including OCEB)				**$ 190.36**			**$ 200.25**	**$ 9.89**	**5.20%**

Loss Factor (%)	5.02%	5.26%

Residential –2000kWh:

Customer Class: **Residential**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 15.1100	1	$ 15.11	$ 18.4700	1	$ 18.47	$ 3.36	22.24%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0086	2000	$ 17.20	$ 0.0105	2000	$ 21.00	$ 3.80	22.09%
Low Voltage Rate Adder	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0007	2000	$ 1.40	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0003	2000	$ 0.60	$ 0.60	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0014	2000	-$ 2.73	-$ 2.73	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 35.70**			**$ 43.59**	**$ 7.89**	**22.09%**
RTSR - Network	per kWh	$ 0.0059	2100.4	$ 12.39	$ 0.0066	2105.11	$ 13.89	$ 1.50	12.12%
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	2100.4	$ 10.29	$ 0.0054	2105.11	$ 11.37	$ 1.08	10.45%
Sub-Total B - Delivery (including Sub-Total A)				**$ 58.38**			**$ 68.85**	**$ 10.46**	**17.92%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	2100.4	$ 13.65	$ 0.0065	2105.11	$ 13.68	$ 0.03	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge	per kWh			$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2100.4	$ 14.70	$ 0.0070	2105.11	$ 14.74	$ 0.03	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	1500.4	$ 118.53	$ 0.0790	1505.11	$ 118.90	$ 0.37	0.31%
Total Bill (before Taxes)				**$ 246.07**			**$ 256.97**	**$ 10.90**	**4.43%**
HST		13%		$ 31.99	13%		$ 33.41	$ 1.42	4.43%
Total Bill (including Sub-total B)				**$ 278.06**			**$ 290.37**	**$ 12.31**	**4.43%**
Ontario Clean Energy Benefit [1]				**-$ 27.81**			**-$ 29.04**	**-$ 1.23**	**4.42%**
Total Bill (including OCEB)				**$ 250.25**			**$ 261.33**	**$ 11.08**	**4.43%**
Loss Factor (%)		5.02%			5.26%				

General Service Less than 50kW – 1000kWh

Customer Class: General Service <50

Consumption 1000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$	% Change
Monthly Service Charge	Monthly	$ 25.5600	1	$ 25.56	$ 31.6200	1	$ 31.62	$ 6.06	23.71%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0100	1000	$ 10.00	$ 0.0124	1000	$ 12.40	$ 2.40	24.00%
Low Voltage Rate Adder	per kWh	$ 0.0006	1000	$ 0.60	$ 0.0006	1000	$ 0.60	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0002	1000	$ 0.20	$ 0.20	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0013	1000	-$ 1.30	-$ 1.30	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 38.15**			**$ 48.37**	**$ 10.22**	**26.78%**
RTSR - Network	per kWh	$ 0.0054	1050.2	$ 5.67	$ 0.0061	1052.55	$ 6.42	$ 0.75	13.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	1050.2	$ 4.52	$ 0.0047	1052.55	$ 4.95	$ 0.43	9.55%
Sub-Total B - Delivery (including Sub-Total A)				**$ 48.34**			**$ 59.73**	**$ 11.40**	**23.58%**
Wholesale Market Service Charge (WMSC)		$ 0.0065	1050.2	$ 6.83	$ 0.0065	1052.55	$ 6.84	$ 0.02	0.22%
Rural and Remote Rate Protection (RRRP)			1050.2	$ -		1052.55	$ -	$ -	
Special Purpose Charge			1050.2	$ -		1052.55	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1050.2	$ 7.35	$ 0.0070	1052.55	$ 7.37	$ 0.02	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	450.2	$ 35.57	$ 0.0790	452.553	$ 35.75	$ 0.19	0.52%
Total Bill (before Taxes)				**$ 138.88**			**$ 150.49**	**$ 11.61**	**8.36%**
HST		13%		$ 18.05	13%		$ 19.56	$ 1.51	8.36%
Total Bill (including Sub-total B)				**$ 156.93**			**$ 170.06**	**$ 13.13**	**8.37%**
Ontario Clean Energy Benefit [1]				**-$ 15.69**			**-$ 17.01**	**-$ 1.32**	**8.41%**
Total Bill (including OCEB)				**$ 141.24**			**$ 153.05**	**$ 11.81**	**8.36%**
Loss Factor (%)		5.02%			5.26%				

General Service Less than 50kW – 2000kWh

Customer Class: **General Service <50**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 25.5600	1	$ 25.56	$ 31.6200	1	$ 31.62	$ 6.06	23.71%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0100	2000	$ 20.00	$ 0.0124	2000	$ 24.80	$ 4.80	24.00%
Low Voltage Rate Adder	per kWh	$ 0.0006	2000	$ 1.20	$ 0.0006	2000	$ 1.20	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0002	2000	$ 0.40	$ 0.40	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0013	2000	-$ 2.60	-$ 2.60	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 48.75**			**$ 60.26**	**$ 11.51**	**23.62%**
RTSR - Network	per kWh	$ 0.0054	2100.4	$ 11.34	$ 0.0061	2105.11	$ 12.84	$ 1.50	13.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	2100.4	$ 9.03	$ 0.0047	2105.11	$ 9.89	$ 0.86	9.55%
Sub-Total B - Delivery (including Sub-Total A)				**$ 69.12**			**$ 83.00**	**$ 13.88**	**20.07%**
Wholesale Market Service Charge (WMSC)		$ 0.0065	2100.4	$ 13.65	$ 0.0065	2105.11	$ 13.68	$ 0.03	0.22%
Rural and Remote Rate Protection (RRRP)			2100.4	$ -		2105.11	$ -	$ -	
Special Purpose Charge			2100.4	$ -		2105.11	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2100.4	$ 14.70	$ 0.0070	2105.11	$ 14.74	$ 0.03	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	1500.4	$ 118.53	$ 0.0790	1505.11	$ 118.90	$ 0.37	0.31%
Total Bill (before Taxes)				**$ 256.81**			**$ 271.12**	**$ 14.31**	**5.57%**
HST		13%		$ 33.39	13%		$ 35.25	$ 1.86	5.57%
Total Bill (including Sub-total B)				**$ 290.20**			**$ 306.37**	**$ 16.17**	**5.57%**
Ontario Clean Energy Benefit [1]				**-$ 29.02**			**-$ 30.64**	**-$ 1.62**	**5.58%**
Total Bill (including OCEB)				**$ 261.18**			**$ 275.73**	**$ 14.55**	**5.57%**
Loss Factor (%)		5.02%			5.26%				

General Service Less than 50kW – 5000kWh

Customer Class: **General Service <50**

Consumption **5000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$**	**% Change**
Monthly Service Charge	Monthly	$ 25.5600	1	$ 25.56	$ 31.6200	1	$ 31.62	$ 6.06	23.71%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0100	5000	$ 50.00	$ 0.0124	5000	$ 62.00	$ 12.00	24.00%
Low Voltage Rate Adder	per kWh	$ 0.0006	5000	$ 3.00	$ 0.0006	5000	$ 3.00	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0002	5000	$ 1.00	$ 1.00	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0013	5000	-$ 6.50	-$ 6.50	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 80.55**			**$ 95.96**	**$ 15.41**	**19.13%**
RTSR - Network	per kWh	$ 0.0054	5251	$ 28.36	$ 0.0061	5262.77	$ 32.10	$ 3.75	13.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	5251	$ 22.58	$ 0.0047	5262.77	$ 24.73	$ 2.16	9.55%
Sub-Total B - Delivery (including Sub-Total A)				**$ 131.48**			**$ 152.80**	**$ 21.32**	**16.21%**
Wholesale Market Service Charge (WMSC)		$ 0.0065	5251	$ 34.13	$ 0.0065	5262.77	$ 34.21	$ 0.08	0.22%
Rural and Remote Rate Protection (RRRP)			5251	$ -		5262.77	$ -	$ -	
Special Purpose Charge			5251	$ -		5262.77	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	5251	$ 36.76	$ 0.0070	5262.77	$ 36.84	$ 0.08	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	4651	$ 367.43	$ 0.0790	4662.77	$ 368.36	$ 0.93	0.25%
Total Bill (before Taxes)				**$ 610.60**			**$ 633.01**	**$ 22.40**	**3.67%**
HST		13%		$ 79.38	13%		$ 82.29	$ 2.91	3.67%
Total Bill (including Sub-total B)				**$ 689.98**			**$ 715.30**	**$ 25.32**	**3.67%**
Ontario Clean Energy Benefit [1]				**-$ 69.00**			**-$ 71.53**	**-$ 2.53**	**3.67%**
Total Bill (including OCEB)				**$ 620.98**			**$ 643.77**	**$ 22.79**	**3.67%**

Loss Factor (%)	5.02%	5.26%

General Service Less than 50kW – 10000kWh

Customer Class: General Service <50

Consumption 10000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $	% Change
Monthly Service Charge	Monthly	$ 25.5600	1	$ 25.56	$ 31.6200	1	$ 31.62	$ 6.06	23.71%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0100	10000	$ 100.00	$ 0.0124	10000	$ 124.00	$ 24.00	24.00%
Low Voltage Rate Adder	per kWh	$ 0.0006	10000	$ 6.00	$ 0.0006	10000	$ 6.00	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0002	10000	$ 2.00	$ 2.00	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0013	10000	-$ 13.01	-$ 13.01	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 133.55**			**$ 155.46**	**$ 21.91**	**16.41%**
RTSR - Network	per kWh	$ 0.0054	10502	$ 56.71	$ 0.0061	10525.5	$ 64.21	$ 7.49	13.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	10502	$ 45.16	$ 0.0047	10525.5	$ 49.47	$ 4.31	9.55%
Sub-Total B - Delivery (including Sub-Total A)				**$ 235.42**			**$ 269.14**	**$ 33.72**	**14.32%**
Wholesale Market Service Charge (WMSC)		$ 0.0065	10502	$ 68.26	$ 0.0065	10525.5	$ 68.42	$ 0.15	0.22%
Rural and Remote Rate Protection (RRRP)			10502	$ -		10525.5	$ -	$ -	
Special Purpose Charge			10502	$ -		10525.5	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	10502	$ 73.51	$ 0.0070	10525.5	$ 73.68	$ 0.16	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	9902	$ 782.26	$ 0.0790	9925.53	$ 784.12	$ 1.86	0.24%
Total Bill (before Taxes)				**$1,200.25**			**$ 1,236.15**	**$ 35.89**	**2.99%**
HST		13%		$ 156.03	13%		$ 160.70	$ 4.67	2.99%
Total Bill (including Sub-total B)				**$1,356.29**			**$ 1,396.85**	**$ 40.56**	**2.99%**
Ontario Clean Energy Benefit [1]				**-$ 135.63**			**-$ 139.69**	**-$ 4.06**	**2.99%**
Total Bill (including OCEB)				**$1,220.66**			**$ 1,257.16**	**$ 36.50**	**2.99%**
Loss Factor (%)		5.02%			5.26%				

General Service Less than 50kW – 15000kWh

Customer Class: General Service <50

Consumption 15000 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$	% Change
Monthly Service Charge	Monthly	$ 25.5600	1	$ 25.56	$ 31.6200	1	$ 31.62	$ 6.06	23.71%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0100	15000	$ 150.00	$ 0.0124	15000	$ 186.00	$ 36.00	24.00%
Low Voltage Rate Adder	per kWh	$ 0.0006	15000	$ 9.00	$ 0.0006	15000	$ 9.00	$ -	0.00%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kWh			$ -	$ 0.0002	15000	$ 3.00	$ 3.00	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0013	15000	-$ 19.51	-$ 19.51	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 186.55**			**$ 214.96**	**$ 28.41**	**15.23%**
RTSR - Network	per kWh	$ 0.0054	15753	$ 85.07	$ 0.0061	15788.3	$ 96.31	$ 11.24	13.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	15753	$ 67.74	$ 0.0047	15788.3	$ 74.20	$ 6.47	9.55%
Sub-Total B - Delivery (including Sub-Total A)				**$ 339.35**			**$ 385.47**	**$ 46.12**	**13.59%**
Wholesale Market Service Charge (WMSC)		$ 0.0065	15753	$ 102.39	$ 0.0065	15788.3	$ 102.62	$ 0.23	0.22%
Rural and Remote Rate Protection (RRRP)			15753	$ -		15788.3	$ -	$ -	
Special Purpose Charge			15753	$ -		15788.3	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	15753	$ 110.27	$ 0.0070	15788.3	$ 110.52	$ 0.25	0.22%
Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
Energy	per kWh	$ 0.0790	15153	$1,197.09	$ 0.0790	15188.3	$ 1,199.88	$ 2.79	0.23%
Total Bill (before Taxes)				**$1,789.91**			**$ 1,839.29**	**$ 49.38**	**2.76%**
HST		13%		$ 232.69	13%		$ 239.11	$ 6.42	2.76%
Total Bill (including Sub-total B)				**$2,022.59**			**$ 2,078.40**	**$ 55.81**	**2.76%**
Ontario Clean Energy Benefit [1]				**-$ 202.26**			**-$ 207.84**	**-$ 5.58**	**2.76%**
Total Bill (including OCEB)				**$1,820.33**			**$ 1,870.56**	**$ 50.23**	**2.76%**

Loss Factor (%)	5.02%		5.26%

General Service Greater than 50kW – 60kW

Customer Class: General Service >50

Consumption 22000 kWh | 60 kW

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	%
Monthly Service Charge	Monthly	$ 165.0800	1	$ 165.08	$ 204.1900	1	$ 204.19	$ 39.11	23.69%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.4136	60	$ 84.82	$ 1.7071	60	$ 102.43	$ 17.61	20.76%
Low Voltage Rate Adder	per kW	$ 0.2877	60	$ 17.26	$ 0.2603	60	$ 15.62	-$ 1.64	-9.52%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kW			$ -	$ 0.0921	60	$ 5.53	$ 5.53	
Deferral/Variance Account Disposition Rate Rider	per kW			$ -	-$ 0.4621	60	-$ 27.73	-$ 27.73	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 269.15**			**$ 304.88**	**$ 35.73**	**13.28%**
RTSR - Network	per kW	$ 2.1814	60	$ 130.88	$ 2.4546	60	$ 147.28	$ 16.39	12.52%
RTSR - Line and Transformation Connection	per kW	$ 1.7374	60	$ 104.24	$ 1.9125	60	$ 114.75	$ 10.51	10.08%
Sub-Total B - Delivery (including Sub-Total A)				**$ 504.28**			**$ 566.90**	**$ 62.63**	**12.42%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	23104.4	$ 150.18	$ 0.0065	23156.2	$ 150.52	$ 0.34	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	23104.4	$ 161.73	$ 0.0070	23156.2	$ 162.09	$ 0.36	0.22%
Energy	per kWh	$ 0.0680	23104.4	$1,571.10	$ 0.0680	23156.2	$ 1,574.62	$ 3.52	0.22%
Total Bill (before Taxes)				**$2,387.28**			**$ 2,454.13**	**$ 66.85**	**2.80%**
HST		13%		$ 310.35	13%		$ 319.04	$ 8.69	2.80%
Total Bill (including Sub-total B)				**$2,697.63**			**$ 2,773.17**	**$ 75.54**	**2.80%**
Ontario Clean Energy Benefit [1]				**-$ 269.76**			**-$ 277.32**	**-$ 7.56**	**2.80%**
Total Bill (including OCEB)				**$2,427.87**			**$ 2,495.85**	**$ 67.98**	**2.80%**

	Current	Proposed
Loss Factor (%)	5.02%	5.26%

General Service Greater than 50kW – 100kW

Customer Class:	General Service >50									
	Consumption	30000	kWh		100	kW				
		Current Board-Approved			Proposed			Impact		
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	%	
Monthly Service Charge	Monthly	$ 165.0800	1	$ 165.08	$ 204.1900	1	$ 204.19	$ 39.11	23.69%	
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%	
Service Charge Rate Adder(s)				$ -			$ -	$ -		
Service Charge Rate Rider(s)				$ -			$ -	$ -		
Distribution Volumetric Rate	per kW	$ 1.4136	100	$ 141.36	$ 1.7071	100	$ 170.71	$ 29.35	20.76%	
Low Voltage Rate Adder	per kW	$ 0.2877	100	$ 28.77	$ 0.2603	100	$ 26.03	-$ 2.74	-9.52%	
Volumetric Rate Adder(s)				$ -			$ -	$ -		
Volumetric Rate Rider(s)				$ -			$ -	$ -		
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66		
LRAM & SSM Rate Rider	per kW			$ -	$ 0.0921	100	$ 9.21	$ 9.21		
Deferral/Variance Account Disposition Rate Rider	per kW			$ -	-$ 0.4621	100	-$ 46.21	-$ 46.21		
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18		
Sub-Total A - Distribution				**$ 337.20**			**$ 368.77**	**$ 31.57**	**9.36%**	
RTSR - Network	per kW	$ 2.1814	100	$ 218.14	$ 2.4546	100	$ 245.46	$ 27.32	12.52%	
RTSR - Line and Transformation Connection	per kW	$ 1.7374	100	$ 173.74	$ 1.9125	100	$ 191.25	$ 17.51	10.08%	
Sub-Total B - Delivery (including Sub-Total A)				**$ 729.08**			**$ 805.48**	**$ 76.40**	**10.48%**	
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	31506	$ 204.79	$ 0.0065	31576.6	$ 205.25	$ 0.46	0.22%	
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -		
Special Purpose Charge				$ -			$ -	$ -		
Standard Supply Service Charge				$ -			$ -	$ -		
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	31506	$ 220.54	$ 0.0070	31576.6	$ 221.04	$ 0.49	0.22%	
Energy	per kWh	$ 0.0680	31506	$2,142.41	$ 0.0680	31576.6	$ 2,147.21	$ 4.80	0.22%	
Total Bill (before Taxes)				**$3,296.82**			**$ 3,378.98**	**$ 82.16**	**2.49%**	
HST		13%		$ 428.59	13%		$ 439.27	$ 10.68	2.49%	
Total Bill (including Sub-total B)				**$3,725.41**			**$ 3,818.24**	**$ 92.83**	**2.49%**	
Ontario Clean Energy Benefit [1]				**-$ 372.54**			**-$ 381.82**	**-$ 9.28**	**2.49%**	
Total Bill (including OCEB)				**$3,352.87**			**$ 3,436.42**	**$ 83.55**	**2.49%**	
Loss Factor (%)		5.02%			5.26%					

General Service Greater than 50kW – 500kW

Customer Class: **General Service >50**

Consumption 250000 kWh 500 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	%
Monthly Service Charge	Monthly	$ 165.0800	1	$ 165.08	$ 204.1900	1	$ 204.19	$ 39.11	23.69%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.4136	500	$ 706.80	$ 1.7071	500	$ 853.55	$ 146.75	20.76%
Low Voltage Rate Adder	per kW	$ 0.2877	500	$ 143.85	$ 0.2603	500	$ 130.15	-$ 13.70	-9.52%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kW			$ -	$ 0.0921	500	$ 46.05	$ 46.05	
Deferral/Variance Account Disposition Rate Rider	per kW			$ -	-$ 0.4621	500	-$ 231.07	-$ 231.07	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 1,017.72**			**$ 1,007.72**	**-$ 10.00**	**-0.98%**
RTSR - Network	per kW	$ 2.1814	500	$ 1,090.70	$ 2.4546	500	$ 1,227.30	$ 136.60	12.52%
RTSR - Line and Transformation Connection	per kW	$ 1.7374	500	$ 868.70	$ 1.9125	500	$ 956.25	$ 87.55	10.08%
Sub-Total B - Delivery (including Sub-Total A)				**$ 2,977.12**			**$ 3,191.27**	**$ 214.15**	**7.19%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	262550	$ 1,706.58	$ 0.0065	263138	$ 1,710.40	$ 3.82	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	262550	$ 1,837.85	$ 0.0070	263138	$ 1,841.97	$ 4.12	0.22%
Energy	per kWh	$ 0.0680	262550	$17,853.40	$ 0.0680	263138	$ 17,893.40	$ 40.00	0.22%
Total Bill (before Taxes)				**$24,374.95**			**$ 24,637.04**	**$ 262.10**	**1.08%**
HST		13%		$ 3,168.74	13%		$ 3,202.82	$ 34.07	1.08%
Total Bill (including Sub-total B)				**$27,543.69**			**$ 27,839.86**	**$ 296.17**	**1.08%**
Ontario Clean Energy Benefit [1]				**-$ 2,754.37**			**-$ 2,783.99**	**-$ 29.62**	**1.08%**
Total Bill (including OCEB)				**$24,789.32**			**$ 25,055.87**	**$ 266.55**	**1.08%**

Loss Factor (%) 5.02% 5.26%

General Service Greater than 50kW – 1000kW

Customer Class: **General Service >50**

Consumption 500000 kWh | 1000 kW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	%
Monthly Service Charge	Monthly	$ 165.0800	1	$ 165.08	$ 204.1900	1	$ 204.19	$ 39.11	23.69%
Smart Meter Rate Adder	Monthly	$ 1.9900	1	$ 1.99			$ -	-$ 1.99	-100.00%
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kW	$ 1.4136	1000	$ 1,413.60	$ 1.7071	1000	$ 1,707.10	$ 293.50	20.76%
Low Voltage Rate Adder	per kW	$ 0.2877	1000	$ 287.70	$ 0.2603	1000	$ 260.30	-$ 27.40	-9.52%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 1.6625	1	$ 1.66	$ 1.66	
LRAM & SSM Rate Rider	per kW			$ -	$ 0.0921	1000	$ 92.10	$ 92.10	
Deferral/Variance Account Disposition Rate Rider	per kW			$ -	-$ 0.4621	1000	-$ 462.13	-$ 462.13	
Stranded Meter Rate Rider	Monthly			$ -	$ 3.1833	1	$ 3.18	$ 3.18	
Sub-Total A - Distribution				**$ 1,868.37**			**$ 1,806.40**	**-$ 61.97**	**-3.32%**
RTSR - Network	per kW	$ 2.1814	1000	$ 2,181.40	$ 2.4546	1000	$ 2,454.60	$ 273.20	12.52%
RTSR - Line and Transformation Connection	per kW	$ 1.7374	1000	$ 1,737.40	$ 1.9125	1000	$ 1,912.50	$ 175.10	10.08%
Sub-Total B - Delivery (including Sub-Total A)				**$ 5,787.17**			**$ 6,173.50**	**$ 386.33**	**6.68%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	525100	$ 3,413.15	$ 0.0065	526277	$ 3,420.80	$ 7.65	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	525100	$ 3,675.70	$ 0.0070	526277	$ 3,683.94	$ 8.24	0.22%
Energy	per kWh	$ 0.0680	525100	$35,706.80	$ 0.0680	526277	$ 35,786.81	$ 80.01	0.22%
Total Bill (before Taxes)				**$48,582.82**			**$ 49,065.05**	**$ 482.23**	**0.99%**
HST		13%		$ 6,315.77	13%		$ 6,378.46	$ 62.69	0.99%
Total Bill (including Sub-total B)				**$54,898.59**			**$ 55,443.50**	**$ 544.91**	**0.99%**
Ontario Clean Energy Benefit [1]				**-$ 5,489.86**			**-$ 5,544.35**	**-$ 54.49**	**0.99%**
Total Bill (including OCEB)				**$49,408.73**			**$ 49,899.15**	**$ 490.42**	**0.99%**

	Current	Proposed
Loss Factor (%)	5.02%	5.26%

Street Lighting – 500kWh & 1kW

Customer Class:	**Street Lighting**								
	Consumption	**500**	**kWh**		**1**	**kW**		**1**	**Connections**
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 0.6600	1	$ 0.66	$ 1.5200	1	$ 1.52	$ 0.86	130.30%
Smart Meter Rate Adder				$ -			$ -	$ -	
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.2363	1	$ 3.24	$ 7.4364	1	$ 7.44	$ 4.20	129.78%
Low Voltage Rate Adder	per kW	$ 0.2194	1	$ 0.22	$ 0.2012	1	$ 0.20	-$ 0.02	-8.30%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider				$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW			$ -			$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kW			$ -	-$ 1.0081	1	-$ 1.01	-$ 1.01	
Sub-Total A - Distribution				**$ 4.12**			**$ 8.15**	**$ 4.03**	**98.01%**
RTSR - Network	per kW	$ 1.6452	1	$ 1.65	$ 1.8512	1	$ 1.85	$ 0.21	12.52%
RTSR - Line and Transformation Connection	per kW	$ 1.3431	1	$ 1.34	$ 1.4785	1	$ 1.48	$ 0.14	10.08%
Sub-Total B - Delivery (including Sub-Total A)				**$ 7.10**			**$ 11.48**	**$ 4.38**	**61.59%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	525.1	$ 3.41	$ 0.0065	526.277	$ 3.42	$ 0.01	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	525.1	$ 3.68	$ 0.0070	526.277	$ 3.68	$ 0.01	0.22%
Energy	per kWh	$ 0.0680	525.1	$ 35.71	$ 0.0680	526.277	$ 35.79	$ 0.08	0.22%
Total Bill (before Taxes)				**$ 49.90**			**$ 54.37**	**$ 4.47**	**8.96%**
HST		13%		$ 6.49	13%		$ 7.07	$ 0.58	8.96%
Total Bill (including Sub-total B)				**$ 56.39**			**$ 61.44**	**$ 5.05**	**8.96%**
Ontario Clean Energy Benefit [1]				**-$ 5.64**			**-$ 6.14**	**-$ 0.50**	**8.87%**
Total Bill (including OCEB)				**$ 50.75**			**$ 55.30**	**$ 4.55**	**8.97%**
Loss Factor (%)		5.02%			5.26%				

Street Lighting – 100000kWh & 350kW

Customer Class:	Street Lighting								
	Consumption	100000	kWh		350	kW		2500	Connections
		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 0.6600	2500	$ 1,650.00	$ 1.5165	2500	$ 3,791.25	$ 2,141.25	129.77%
Smart Meter Rate Adder				$ -			$ -	$ -	
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.2363	350	$ 1,132.71	$ 7.4364	350	$ 2,602.74	$ 1,470.04	129.78%
Low Voltage Rate Adder	per kW	$ 0.2194	350	$ 76.79	$ 0.2012	350	$ 70.42	-$ 6.37	-8.30%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider				$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW			$ -			$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kW			$ -	-$ 1.0081	350	-$ 352.83	-$ 352.83	
Sub-Total A - Distribution				**$ 2,859.50**			**$ 6,111.58**	**$ 3,252.08**	**113.73%**
RTSR - Network	per kW	$ 1.6452	350	$ 575.82	$ 1.8512	350	$ 647.92	$ 72.10	12.52%
RTSR - Line and Transformation Connection	per kW	$ 1.3431	350	$ 470.09	$ 1.4785	350	$ 517.48	$ 47.39	10.08%
Sub-Total B - Delivery (including Sub-Total A)				**$ 3,905.40**			**$ 7,276.97**	**$ 3,371.57**	**86.33%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	105020	$ 682.63	$ 0.0065	105255	$ 684.16	$ 1.53	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	105020	$ 735.14	$ 0.0070	105255	$ 736.79	$ 1.65	0.22%
Energy	per kWh	$ 0.0680	105020	$ 7,141.36	$ 0.0680	105255	$ 7,157.36	$ 16.00	0.22%
Total Bill (before Taxes)				**$ 12,464.53**			**$ 15,855.28**	**$ 3,390.75**	**27.20%**
HST		13%		$ 1,620.39	13%		$ 2,061.19	$ 440.80	27.20%
Total Bill (including Sub-total B)				**$ 14,084.92**			**$ 17,916.47**	**$ 3,831.55**	**27.20%**
Ontario Clean Energy Benefit [1]				**-$ 1,408.49**			**-$ 1,791.65**	**-$ 383.16**	**27.20%**
Total Bill (including OCEB)				**$ 12,676.43**			**$ 16,124.82**	**$ 3,448.39**	**27.20%**
Loss Factor (%)		5.02%			5.26%				

Unmetered Scattered Load – 150kWh

Customer Class: Unmetered Scattered Load

Consumption 150 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 12.7800	1	$ 12.78	$ 16.7800	1	$ 16.78	$ 4.00	31.30%
Smart Meter Rate Adder				$ -			$ -	$ -	
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0099	150	$ 1.49	$ 0.0130	150	$ 1.95	$ 0.47	31.31%
Low Voltage Rate Adder	per kWh	$ 0.0007	150	$ 0.11	$ 0.0006	150	$ 0.09	-$ 0.02	-14.29%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM & SSM Rate Rider				$ -			$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0015	150	-$ 0.22	-$ 0.22	
Sub-Total A - Distribution				**$ 14.37**			**$ 18.60**	**$ 4.23**	**29.42%**
RTSR - Network	per kWh	$ 0.0054	157.53	$ 0.85	$ 0.0061	157.883	$ 0.96	$ 0.11	13.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	157.53	$ 0.68	$ 0.0047	157.883	$ 0.74	$ 0.06	9.55%
Sub-Total B - Delivery (including Sub-Total A)				**$ 15.90**			**$ 20.30**	**$ 4.40**	**27.71%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	157.53	$ 1.02	$ 0.0065	157.883	$ 1.03	$ 0.00	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	157.53	$ 1.10	$ 0.0070	157.883	$ 1.11	$ 0.00	0.22%
Energy	per kWh	$ 0.0680	157.53	$ 10.71	$ 0.0680	157.883	$ 10.74	$ 0.02	0.22%
Total Bill (before Taxes)				**$ 28.74**			**$ 33.17**	**$ 4.43**	**15.43%**
HST		13%		$ 3.74	13%		$ 4.31	$ 0.58	15.43%
Total Bill (including Sub-total B)				**$ 32.47**			**$ 37.48**	**$ 5.01**	**15.43%**
Ontario Clean Energy Benefit [1]				**-$ 3.25**			**-$ 3.75**	**-$ 0.50**	**15.38%**
Total Bill (including OCEB)				**$ 29.22**			**$ 33.73**	**$ 4.51**	**15.43%**
Loss Factor (%)		5.02%			5.26%				

Unmetered Scattered Load – 4500kWh

Customer Class: Unmetered Scattered Load

Consumption 4500 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 12.7800	1	$ 12.78	$ 16.7800	1	$ 16.78	$ 4.00	31.30%
Smart Meter Rate Adder				$ -			$ -	$ -	
Service Charge Rate Adder(s)				$ -			$ -	$ -	
Service Charge Rate Rider(s)				$ -			$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0099	4500	$ 44.55	$ 0.0130	4500	$ 58.50	$ 13.95	31.31%
Low Voltage Rate Adder	per kWh	$ 0.0007	4500	$ 3.15	$ 0.0006	4500	$ 2.70	-$ 0.45	-14.29%
Volumetric Rate Adder(s)				$ -			$ -	$ -	
Volumetric Rate Rider(s)				$ -			$ -	$ -	
Smart Meter Disposition Rider				$ -			$ -	$ -	
LRAM & SSM Rate Rider				$ -			$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kWh			$ -	-$ 0.0015	4500	-$ 6.66	-$ 6.66	
Sub-Total A - Distribution				**$ 60.48**			**$ 71.32**	**$ 10.84**	**17.92%**
RTSR - Network	per kWh	$ 0.0054	4725.9	$ 25.52	$ 0.0061	4736.49	$ 28.89	$ 3.37	13.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	4725.9	$ 20.32	$ 0.0047	4736.49	$ 22.26	$ 1.94	9.55%
Sub-Total B - Delivery (including Sub-Total A)				**$ 106.32**			**$ 122.47**	**$ 16.15**	**15.19%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0065	4725.9	$ 30.72	$ 0.0065	4736.49	$ 30.79	$ 0.07	0.22%
Rural and Remote Rate Protection (RRRP)				$ -			$ -	$ -	
Special Purpose Charge				$ -			$ -	$ -	
Standard Supply Service Charge				$ -			$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	4725.9	$ 33.08	$ 0.0070	4736.49	$ 33.16	$ 0.07	0.22%
Energy	per kWh	$ 0.0680	4725.9	$ 321.36	$ 0.0680	4736.49	$ 322.08	$ 0.72	0.22%
Total Bill (before Taxes)				**$ 491.48**			**$ 508.49**	**$ 17.01**	**3.46%**
HST		13%		$ 63.89	13%		$ 66.10	$ 2.21	3.46%
Total Bill (including Sub-total B)				**$ 555.37**			**$ 574.60**	**$ 19.23**	**3.46%**
Ontario Clean Energy Benefit [1]				**-$ 55.54**			**-$ 57.46**	**-$ 1.92**	**3.46%**
Total Bill (including OCEB)				**$ 499.83**			**$ 517.14**	**$ 17.31**	**3.46%**

	Current	Proposed
Loss Factor (%)	5.02%	5.26%

Exhibit 9 Deferral and Variance Accounts

OVERVIEW

The information contained in this exhibit includes the status and description of Grimsby Power Inc.'s deferral and variance accounts, the proposed disposition of certain account balances, and the rate riders required for recovery or refund of the account balances.

2009 IRM DEFERRAL/VARIANCE ACCOUNT DISPOSITION (2010) RATE RIDER

2009 IRM Approval and Board Directive

On April 16, 2010 the Ontario Energy Board's Decision and Order EB-2009-0198 approved a one-year disposition for Grimsby Power Inc.'s Group 1 deferral and asset balances in the amount of $1,135,549 (CR), which includes a debit balance of $408,422 in the 1588 Global Adjustment sub-account and $19,721 in the Recovery of Regulatory Assets Balances. The approved amount represented the December 31, 2008 balances and projected interest to April 30, 2010 for the Group 1 Accounts as presented in below Table 9.1. In 2010, the approved balances were transferred to account 1595.

Table 9.1 2010 IRM Approved Group 1 Amounts for Disposition

Account Description	Account Number	Principal Amounts	Interest amounts	Total amounts
LV Variance Account	1550	(117,441)	(8,369)	(125,810)
RSVA - Wholesale Market Service Charge	1580	(392,710)	(18,817)	(411,527)
RSVA - Retail Transmission Network Charge	1584	(66,358)	(31,056)	(97,414)
RSVA - Retail Transmission Connection Charge	1586	(340,259)	(45,341)	(385,600)
RSVA - Power (Excluding Global Adjustments)	1588	(663,859)	(62,904)	(726,763)
RSVA - Power (Global Adjustment Sub-account)	1588	403,135	5,287	408,422
Recovery of Regulatory Asset Balances	1590	41,942	(22,221)	19,721
		(1,135,550)	**(183,421)**	**(1,318,971)**

At the time of the 2010 IRM application, Grimsby Power Inc.'s billing system was unable to implement a separate rate rider to non-RPP customers to dispose of the global adjustment sub-account balance before May 1, 2010. The debit balance of $408,422 was included in the Deferral/ Variance Account Disposition (2010) rate rider. Grimsby Power Inc. has included interest on these account balances using the Board's prescribed interest rates to April 2010. The Decision and Order EB-2009-0198 also stated:

> *"The Board directs Grimsby Power to further investigate and report to the Board in a proceeding no later than the rebasing proceeding Grimsby Power's projection of the costs that it would incur to accommodate the establishment of a separate rate rider to dispose of the global adjustment sub account".*

During preliminary discussions with the Grimsby Power Inc.'s Customer Information System (CIS) provider, Canadian Niagara Power Inc (CNPI) had anticipated a one-time incremental cost to accommodate the required programming changes. Subsequent to the May 1, 2010 IRM2 Decision, Grimsby Power Inc. had worked with CNPI to find a solution that would allow a separate rate rider for non-RPP customers. However, at this point of time no decision has been made as to how these programming changes can be accommodated.

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS

The schedule that follows contains the status of the Deferral and Variance Accounts ("DVAs") currently used by Grimsby Power Inc. Their account descriptions and balances as at December 31, 2010 and the proposed recovery amounts are summarized in the commentary that follows. Tables 9.2, 9.3 and 9.4 contain the detailed information for each account.

GROUP 1 ACCOUNTS

1580 Retail Settlement Variance Account – Wholesale Market service Charges

This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. Grimsby Power Inc uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, Grimsby Power Inc. is requesting disposition of the December 31, 2010 audited balance plus the forecasted interest through Dec 31, 2011 for account 1580. The requested amount is a credit of ($242,435).

1584 Retail Settlement Variance Account – Retail Transmission Network Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Transmission Network Charge. Grimsby Power Inc. uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, Grimsby Power Inc. is requesting disposition of the December 31, 2010 audited balance, plus the forecasted interest through Dec 31, 2011 for account 1584. The requested amount is a credit of ($21,989).

1586 Retail Settlement Variance Account – Retail Transmission Connection Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Transmission Connection Charge. Grimsby Power Inc. uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, Grimsby Power Inc. is requesting disposition of the December 31, 2010 audited balance, plus the forecasted interest through Dec 31, 2011 for account 1586. The requested amount is a credit of ($161,076).

1588 Retail Settlement Variance Account – Power

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to Grimsby Power Inc. using the settlement invoice from the Independent Electricity System Operator (IESO). Grimsby Power Inc. uses the accrual method. The variance between Board-approved and actual line losses is reflected in Account 1588 for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, Grimsby Power Inc. is requesting disposition of the December 31, 2010 audited balance, plus the forecasted interest through Dec 31, 2011 for account 1588 - Power. The requested amount is a credit ($795,458).

1588 Retail Settlement Variance Account – Power, Sub-Account Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to customers and the global adjustment charge to Grimsby Power Inc. using the settlement invoice from the IESO. Grimsby Power Inc. uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, Grimsby Power Inc. is requesting disposition of the December 31, 2010 audited balance, plus the forecasted interest through Dec 31, 2011 for account 1588 sub account Global Adjustment. The requested amount is $1,125,389.

Grimsby Power Inc. plans to dispose the global adjustment in a similar manner as the 2008 balances in the 2010 IRM Application, through a rate rider that would apply to all customers in the affected rate class. It is our understanding that CNPI resources, our CIS provider, has been in the midst of an SAP application upgrade and the transition to time of use billing. This has delayed the project to upgrade the Grimsby Power Inc system to have a separate rate rider to dispose of the Global Adjustment amount to Non-RPP customers.

1590 Recovery of Regulatory Asset Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers of

Grimsby Power Inc. In accordance with the Board's Decision and Order for Grimsby Power Inc.'s 2006 EDR Application (EB-2005-0371), this Regulatory Asset rate rider was removed from Distribution Rates effective May 1, 2006. Separate sub-accounts are maintained for expenses, interest, and recovery amounts. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, Grimsby Power Inc. is requesting disposition of the December 31, 2010 audited balance. The requested amount is a residual interest amount of ($361).

Grimsby Power Inc. established at the end of 2009 account 1590 Sub-account - Future Tax Liabilities in order to set-up the grossed-up future payments in lieu of taxes benefit and corresponding regulatory liabilities. The sub-account balance at the end of 2010 is $1,013,324. Each year the Future Tax Liability is recalculated and the differences recorded. No interest is recorded on this sub-account. For 2012, Grimsby Power Inc. is not seeking disposition of the December 31, 2010 audited balance in this application.

1595 Disposition and Recovery of Regulatory Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts approved by the Board in Grimsby Power Inc.'s 2010 IRM (EB-2009-0198). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

In accordance with the OEB EB-2009-0198 Decision and Order for Grimsby Power Inc.'s 2010 IRM rate approval, the December 31, 2008 balances and projected interest to April 30, 2010 totalling ($1,318,971) were transferred to account 1595 in May, 2010. As of April 2011, the disposition period for this account was completed. However, Grimsby Power Inc. is not seeking disposition of this account since the April 2011 balance has not been audited.

GROUP 2 ACCOUNTS

1508 Other Regulatory Assets – Sub-Account IFRS Transition Costs

This account includes amounts paid for administrative incremental International Financial Reporting Standards (IFRS) transition costs. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Grimsby Power Inc. has established account 1508 – sub account IFRS Transition Costs in accordance with the Board Requirements. For 2012, Grimsby Power Inc. is not seeking disposition of the December 31, 2010 audited balance of $2,208 in this application. In accordance with the Board's instructions, the balance in this sub-account will be included for review and disposition in a future rate application immediately after the IFRS transition period.

1508 Other Regulatory Assets – Sub – Account Late Payment Litigation Costs

This account includes the costs arising from the settlement of the LPP class action law suit that are sought for recovery from all ratepayers. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. Grimsby Power Inc elected to recover the amount approved for its share of the class action costs in the 2011 IRM (EB-2010-0295). OEB approved Grimsby Power Inc.'s proposed rate riders starting May 01, 2011. At the end of 2010 the amount of $ 23,236.06 was recorded as an accrual.

1518 Retail Cost Variance Account – Retail

This account is used to recover the net difference between the revenue derived from establishing service agreements, distributor consolidated billing and related contract administration, monitoring, and other expenses necessary to maintain the contract. Grimsby Power Inc. uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, Grimsby Power Inc. is requesting disposition of the December 31, 2010 audited balance plus the forecasted interest through Dec 31, 2011 for account 1518. The requested amount is a credit of ($30,305).

1548 Retail Cost Variance Account – Service Transaction Request

This account is used to recover the net of revenues derived from services in the form of transaction request and processing and the incremental cost of labour, internal information system maintenance costs, and delivery costs related to the provision of the services. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2012, Grimsby Power Inc. is requesting disposition of the December 31, 2010 audited balance plus the forecasted interest through Dec 31, 2011 for account 1518. The requested amount is a debit of $ 27,095.

1521 Special Purpose Charge (SPC) Assessment Variance Account

This account includes the amount remitted to the Minister of Finance for the SPC assessment. Separate sub-accounts are maintained to record amounts recovered from customers over a one-year period commencing on the date that recovery amounts are billed to customers. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

As per OEB's letters dated April 9 and April 23, 2011, Grimsby Power Inc. recovered the SPC assessment over a one-year period. The 2010 audit balance of $28,306 was recovered through rate adder during the period of January 2011 to April 30, 2011, conclusive. The residual amount of ($802) is a credit of ($1,164.55) accrual and $ 362.75 interest. Grimsby Power inc. is requesting the disposition of the residual credit balance of ($802).

1525 Miscellaneous Deferred Debits Account

Grimsby Power Inc. established account 1525 Miscellaneous Deferred Debits Account to include the cost of issuing refund cheques/credits to electricity consumers in accordance with government legislation. As part of the Board's Decision and Order for Grimsby Power Inc.'s 2006 EDR Application (EB-2005-0371), part of this account balance was disposed.

Grimsby Power Inc. is not seeking disposition of the December 31, 2010 audited balance of $1,245.

1532 Renewable Connection OM&A Deferral Account

This account includes the amounts paid for incremental operating, maintenance, amortization and administrative expenses directly related to "renewable enabling improvements" as defined in the OEB Guidelines G-2009-0087 "Deemed Conditions of License: Distribution System Planning", June 16, 2009. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Grimsby Power Inc. has established the 1532 Renewable Connection OM&A Deferral Account in accordance with the Board's Guidelines on "Deemed

Conditions of License: Distribution System Planning (G-2009-0087)" released June 16, 2009, to track costs associated with renewable connection OM&A. Grimsby Power Inc. is not seeking disposition of the December 31, 2010 audited balance of $15,532 in this application.

1555 Smart Meter Capital and Recovery Offset Variance

This account records the net of the amounts paid for direct capital costs related to the smart meter program and the amounts charged to customers using the OEB - approved smart meter rate adder. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Grimsby Power Inc. is requesting closing of the December 31, 2010 audited balance for account 1555 – Smart Meter Capital and Recovery Offset Variance. The closing amount of $1,510,225 will be removed from the deferral account and include in the meter fixed asset account at the beginning of 2012.

Grimsby Power Inc. is following the Smart Meter Funding and Cost Recovery Guideline dated October 22, 2008 (G-2008-0002) is seeking approval for a smart meter cost recovery rate rider. This rider will true-up the difference in the revenue requirement for smart meters installed from 2009 to 2011 and the amounts collected by the smart meter rate adder up to the end of December 2011. The smart meter cost recovery rate rider is designed to recover a true-up value of $209,193 over a one year period. Additional information on the smart meter cost recovery rate rider is available later in this exhibit.

For the stranded meters Grimsby Power Inc. is requesting recovery of the December 31, 2010 audited balance, plus the forecasted accrual through a stranded meter rate recovery rider as detailed later in this exhibit. The requested amount is a debit of $400,564. This amount will remain in the sub-account 1555 Stranded Meters and the rate recovery rider will be recorded in this sub-account.

1556 Smart Meter OM&A Variance

This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account. Grimsby Power Inc. is requesting closing of the December 31, 2010 audited balance plus the 2011 forecasted amounts for account 1556 – Smart Meter OM&A Variance. The requested amount of $ 272,310 is detailed later in this exhibit.

1562 Deferred Payments in Lieu of Taxes

This account records the amount resulting from the OEB-approved PILs methodology for determining the deferral account allowance and the PILs proxy amount determined for periods ending in 2006.

Grimsby Power Inc. is aware of the results of the combined PILs proceeding (EB-2008-0381) released on June 24, 2011. Grimsby Power Inc. will file for disposition of account 1562 in accordance with the Decision and Order. However, Grimsby Power Inc. will need time to determine the methodology used in the above proceeding and create a justifiable method to determine the exact amount for disposition. As Grimsby Power Inc.'s cost of service application is nearing completion and the method of disposition of account 1562 is still somewhat uncertain Grimsby Power Inc. will submit its supporting documentation for the disposition of account 1562 at a later date.

Account Balances

The following Table 9.2 contains account balances from the 2010 Audited Financial Statements as at December 31, 2010 and agrees to the 2010 year end balances for RRR filing E2.1.7 Trial Balance as filed April 30, 2011 with the OEB.

Table 9.2 Deferral and Variance Accounts – Audited Balances – December 31, 2010

Account Description		Audited Financial Statements: Principal Amounts as of Dec 31, 2010	Audited Financial Statements: Interest Amounts as of Dec 31, 2010	Audited Financial Statements: Dec 31, 2010 Total	Projected Interest from Jan 1, 2011 to Dec 31, 2011 on Dec 31 -10 balance	Total Claim
Group 1 Accounts						
LV Variance Account	1550	(130,199)	(1,140)	(131,339)	(1,791)	(133,130)
RSVA - Wholesale Market Service Charge	1580	(235,730)	(2,463)	(238,192)	(4,243)	(242,435)
RSVA - Retail Transmission Network Charge	1584	(21,839)	(78)	(21,917)	(72)	(21,989)
RSVA - Retail Transmission Connection Charge	1586	(157,828)	(1,095)	(158,923)	(2,154)	(161,076)
RSVA - Power (excluding Global Adjustment)	1588	(783,827)	(3,151)	(786,977)	(8,480)	(795,458)
RSVA - Power - Sub-Account - Global Adjustment	1588	1,099,194	10,037	1,109,231	16,158	1,125,389
Recovery of Regulatory Asset Balances	1590		(361)	(361)		(361)
Future Tax liabilities	1590	1,013,324		1,013,324		
Disposition and Recovery of Regulatory Balances	1595	(352,628)	(187,666)	(540,294)		
Group 1 Sub-Total (including Account 1588 - Global Adjustment)	**1588**	**430,468**	**(185,916)**	**244,551**	**(581)**	**(229,060)**
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		**(668,726)**	**(195,592)**	**(864,319)**	**(16,739)**	**(1,354,088)**
RSVA - Power - Sub-Account - Global Adjustment		**1,099,194**	**10,037**	**1,109,231**	**16,158**	**1,125,389**
Group 2 Accounts						
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	2,197	12	2,208		
Other Regulatory Assets - Sub-Account - Late Payment Litigation Costs	1508	23,236		23,236		
Retail Cost Variance Account - Retail	1518	(29,423)	(449)	(29,873)	(433)	(30,305)
Misc. Deferred Debits	1525	1,245		1,245		
Renewable Generation Connection OM&A Deferral Account	1532	15,481	51	15,532		
Retail Cost Variance Account - STR	1548	26,312	396	26,708	387	27,095
Group 2 Sub-Total		**39,046**	**10**	**39,056**	**(46)**	(3,211)
Deferred Payments in Lieu of Taxes	1562	(208,938)	(2,108)	(211,045)		
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(9,362)		(9,362)		(9,362)
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		**251,214**	**(188,014)**	**63,200**	**(627)**	(241,632)
Special Purpose Charge Assessment Variance Account	**1521**				**(802)**	(802)
Total including Account 1521 [1]		**251,214**	**(188,014)**	**63,200**	**(1,429)**	(242,434)
The following is not included in the total claim but are included on a memo basis:						
Deferred PILs Contra Account [8]	1563	208,938	2,108	211,045		211,045
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	9,362		9,362		9,362

DEFERRAL AND VARIANCE ACCOUNTS REQUESTED

Grimsby Power Inc. is requesting the continuation of all Group 1 deferral or variance accounts and the following Group 2 deferral or variance accounts:

- Future Tax Liability for recording the grossed-up future payments in lieu of taxes benefit and corresponding regulatory liabilities.

- Disposition and Recovery of Regulatory Balances for recovery in rates or payments/credits made to customers
- IFRS Transition Costs Account for the IFRS transition costs
- Late Payment litigation Costs to record the payment and recovery of late payment litigation costs pertaining to the Municipal Electrical Utilities Late Payment Class Action proceeding. Grimsby Power Inc.'s share of this proceeding is $23,236.06.
- Miscellaneous Deferred Debits
- Renewable Connection OM&A Deferral Account to record "renewable enabling improvements" expenses

CONTINUATION OF IFRS TRANSITION COST SUB – ACCOUNT 1508

In 2010, the OEB approved sub-account 1508 IFRS Transition Costs, to record incremental costs incurred in relation to the transition to International Financial Reporting Standards (IFRS). The July 28, 2009 Report of the Board EB-2008-0408, Transition to International Financial Reporting Standards, stated *"As required by the Canadian Accounting Standards Board, Canadian Generally Accepted Accounting Principles (CGAAP) for publically accountable enterprises will transition to IFRS effective January 1, 2011".*

It was expected by the Board that incremental transition costs incurred after the January 1, 2011 were expected to be minimal.

On July 20 and 22, 2010, the International Accounting Standards Board (IASB) held deliberations on rate-regulated activities and made the decision to continue with its project addressing the recognition, measurement and disclosure of regulatory assets and liabilities, and not to develop transitional guidance for use by first-time adopters.

The Canadian Accounting Standards Board (AcSB) discussed these developments and decided to amend the CICA Handbook to require that qualifying entities with rate-regulated activities adopt IFRS for the first time no later than fiscal periods beginning on or after January 1, 2012.

As a qualifying entity, Grimsby Power Inc. will be in a position to implement IFRS on January 1, 2012. Grimsby Power Inc. therefore requests the continuation of the IFRS Transition Cost sub-account 1508 until December 31, 2012.

CONTINUATION OF RENEWABLE CONNECTION OM&A COST SUB – ACCOUNT 1532

Grimsby Power Inc. will continue to record incremental operating, maintenance, amortization and administrative expenses directly related to connect renewable generation facilities, and renewable enabling improvements as well as expenses associated with preparing its GEA Plan and expenses associated with the Customer Information System to enable the automated settlement of FIT and microFIT contracts to this account.

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

Grimsby Power Inc. is requesting disposition of the variance accounts noted below according to the Report of the Board EB-2008-0046, which states that "at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline".

Grimsby Power Inc. has followed the guidelines in the Report of the Board and requests disposition over a one-year period. Grimsby Power Inc. has provided an excel version of the continuity schedule with its application filing titled "Grimsby_2012_EDDVAR_Continuity_Schedule".

Grimsby Power Inc. is requesting the disposition of following Group 1 and Group 2 Accounts shown in Table 9.3. These amounts are comprised of the audited balances as of December 31, 2010 less the 2010 IRM approved disposition amounts, and the forecasted interest through December 31, 2011.

Table 9.3 2012 Deferral and Variance Account Disposition Amounts

Account Description	Allocator	Account	Total amount
Group 1 Accounts			
LV Variance Account	kWh	1550	(133,130)
RSVA - Wholesale Market Service Charge	kWh	1580	(242,435)
RSVA - Retail Transmission Network Charge	kWh	1584	(21,989)
RSVA - Retail Transmission Connection Charge	kWh	1586	(161,076)
RSVA - Power (excluding Global Adjustment)	kWh	1588	(795,458)
RSVA - Power - Sub-Account - Global Adjustment	kWh	1588	1,125,389
Recovery of Regulatory Asset Balances	Recovery share	1590	(361)
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		**1588**	**(229,059)**
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)			
RSVA - Retail Transmission Connection Charge			
Group 2 Accounts			
Retail Cost Variance Account - Retail	# of Customers	1518	(30,305)
Special Purpose Charge Assessment Variance Account	kWh	1521	(802)
Retail Cost Variance Account - STR	# of Customers	1548	27,095
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	# of Customers	1592	(9,362)
Group 2 Sub-Total			**(13,374)**
Total Disposition Amount Requested			**(242,434)**

METHODS OF DISPOSITION OF ACCOUNTS AND BILL IMPACTS

Allocators

Grimsby Power Inc. submits the following Allocators in Table 9.4 used to assign the Group 1 and Group 2 balances to each rate class.

Table 9.4 Allocators

2012 Data By Class	kWhs	Cust. Num.'s
RESIDENTIAL CLASS	92,606,843	9,703
GENERAL SERVICE <50 KW CLASS	18,314,894	683
GENERAL SERVICE >50 KW NON TIME OF USE	68,877,755	100
GENERAL SERVICE >50 KW TIME OF USE		
STANDBY		
LARGE USER CLASS		
UNMETERED & SCATTERED LOADS	355,293	80
SENTINEL LIGHTS		
STREET LIGHTING	1,578,145	2,548
Totals	181,732,931	13,114

Allocators	kWhs	Cust. Num.'s
RESIDENTIAL CLASS	51%	74%
GENERAL SERVICE <50 KW CLASS	10%	5%
GENERAL SERVICE >50 KW NON TIME OF USE	38%	1%
GENERAL SERVICE >50 KW TIME OF USE	0%	0%
STANDBY	0%	0%
LARGE USER CLASS	0%	0%
UNMETERED & SCATTERED LOADS	0%	1%
SENTINEL LIGHTS	0%	0%
STREET LIGHTING	1%	19%
Totals	100%	100%

The allocators used to distribute account balances to each rate class are summarized in Tables 9.5, and 9.6 below.

Table 9.5 Group 1 Balances

	LV Variance Account	RSVA - Wholesale Market Service Charge	RSVA - Retail Transmission Network Charge	RSVA - Retail Transmission Connection Charge	RSVA - Power (excluding Global Adjustment)	RSVA - Power - Sub-Account - Global Adjustment	Recovery of Regulatory Asset Balances	Total
Group 1 Accounts	1550	1580	1584	1586	1588	1588	1590	
Account Disposition Amount	(133,130)	(242,435)	(21,989)	(161,076)	(795,458)	1,125,389	(361)	(229,060)
Allocator	kWh	kWh	kWh	kWh	kWh	kWh	Recovery share	
Residential	(67,840)	(123,536)	(11,205)	(82,078)	(405,336)	573,456	(184)	(116,722)
GS < 50 KW	(13,417)	(24,432)	(2,216)	(16,233)	(80,163)	113,413	(36)	(23,084)
GS > 50 KW	(50,457)	(91,888)	(8,334)	(61,051)	(301,494)	426,545	(137)	(86,816)
Small Scattered Load	(260)	(474)	(43)	(315)	(1,555)	2,201	(1)	(448)
Street Lighting	(1,156)	(2,106)	(191)	(1,399)	(6,909)	9,774	(3)	(1,989)
Total	**(133,130)**	**(242,435)**	**(21,989)**	**(161,076)**	**(795,458)**	**1,125,389**	**(361)**	**(229,060)**

Table 9.6 Group 2 Balances

	Retail Cost Variance Account - Retail	Special Purpose Charge Assessment Variance Account	Retail Cost Variance Account - STR	Sub-Account HST/OVAT	Total
Account Description	1518	1521	1548	1592	
Account Disposition Amount	(30,305)	(802)	27,095	(9,362)	(13,374)
Allocator	# of Customers	kWh	# of Customers	# of Customers	
Residential	(22,423)	(409)	20,047	(6,927)	(9,711)
GS < 50 KW	(1,578)	(81)	1,411	(488)	(736)
GS > 50 KW	(231)	(304)	207	(71)	(400)
Small Scattered Load	(185)	(2)	165	(57)	(78)
Street Lighting	(5,888)	(7)	5,264	(1,819)	(2,450)
Total	**(30,305)**	**(802)**	**27,095**	**(9,362)**	**(13,374)**

Calculation of Rate Riders

Table 9.7 summarizes the variables used to determine the proposed regulatory asset rate riders by rate class for the Group 1 and Group 2 accounts. The billing determinants are based on the 2012 Test Year forecast load data and calculated for a one-year disposition period.

Table 9.7 2012 Deferral and Variance Account Rate Rider by Rate Class

Rate Class	Group 1	Group 2	Total	2012 Forecast quantities	Billing Factor	Rate
Residential	(116,722)	(9,711)	(126,433)	92,606,843	kWhs	(0.0014)
GS < 50 KW	(23,084)	(736)	(23,820)	18,314,894	kWhs	(0.0013)
GS > 50 KW	(86,816)	(400)	(87,216)	188,723	kW	(0.4621)
Small Scattered Load	(448)	(78)	(526)	355,293	kWhs	(0.0015)
Street Lighting	(1,989)	(2,450)	(4,439)	4,403	kW	(1.0081)
Total	**(229,060)**	**(13,374)**	**(242,434)**			

Proposed Rates and Bill Impacts

Grimsby Power Inc. also requests at this time to establish the same volumetric rate riders for the Unmetered Scattered Load rate class and the General Service < 50 rate class. The proposed rates for the RSVA and non-RSVA accounts are summarized along with the bill impacts in Table 9.8.

Table 9.8 Proposed Rates and Bill Impacts

Rate Class	Sample quantities	Proposed 2012 DVA	Bill Impact on Total Bill
Residential	800 kWh	(1.09)	(0.86%)
GS < 50 KW	2,000 kWh	(2.60)	(0.85%)
GS > 50 KW	200,000 kWh 500 kW	(231.07)	(1.00%)
Small Scattered Load	250 kWh	(0.37)	(0.74%)
Street Lighting	2500 conn, 100,000 kWh, 350kW	(352.83)	(1.97%)

SMART METER PROPOSAL

Overview

Grimsby Power Inc. has installed 9,822 smart meters as at December 31, 2010 and plans to complete its deployment by the end of December 2011 with 10,072 meters. Smart meter infrastructure began being installed in 2009 with the AMI systems and structures, including the advanced metering control computer ("AMCC") and advanced metering regional collector ("AMRC"). The mass deployment of meters occurred in 2010.

In this Application, Grimsby Power Inc. seeks recovery of the revenue requirement in respect of these smart meters with a gross capital cost value as at the end of 2011 of $1.51 million. Projected 2012 costs in this application are for Billing/Customer Service software and operating costs related to bill presentment, bill print modifications, and for smart meter entity MDM/R costs which were based on the OEB's 2008 report.

On October 22, 2008 the Board issued "*Smart Meter Funding and Cost Recovery Guideline (G-2008-002)*" ("SM Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities. As set out in the SM Guideline, and as part of its 2006 to 2011 Rate Applications, Grimsby Power Inc. requested, and the Board approved, the charge of smart meter funding adders as follows:

- Approved Rates Effective May 1, 2006 – $0.27 per customer per month
- Approved Rates Effective May 1, 2007 – $0.27 per customer per month
- Approved Rates Effective May 1, 2008 – $0.27 per customer per month
- Approved Rates Effective May 1, 2009 – $0.27 per customer per month
- Approved Rates Effective May 1, 2010 – $1.00 per customer per month
- Approved Rates Effective May 1, 2011 – $1.99 per customer per month

The smart meter funding adder was intended to provide funding in the case where a distributor, which was authorized and clearly intended to install smart meters as part of the smart meter initiative.

Grimsby Power Inc.'s smart meter program details are noted below:

- Grimsby Power Inc. is a member of the Niagara Erie Power Alliance ("NEPA") – a cooperative venture of 11 local distribution companies ("LDCs") in south eastern Ontario – who has been planning a collective and collaborative approach to their Advanced Metering Infrastructure ("AMI") procurement and installation. The NEPA group has also engaged Util-Assist (a consulting firm) to provide consulting assistance in this regard.

- Smart meters were procured pursuant to and in compliance with the August 14, 2007 Request for Proposal ("RFP") issued by London Hydro Inc. Through this process, on August 1, 2008, PRP International Inc. determined and verified that the highest ranked AMI proponent for the NEPA group was KTI/Sensus Limited.
- Contracts were put in place in 2009 to purchase the AMI which meets only the minimum functionality adopted in O. Reg. 425/06.
- It was estimated that the total capital installed costs during this program would be in the order of $1,707,194, or $187 per installed meter.
- A NEPA group RFP for a temporary Operational Data Storage ("ODS") was released and finalized in 2010. The ODS will assist the NEPA group with validating and auditing smart meter/AMI data until the centralized MDM/R is fully operational.
- By letter dated June 26, 2009, the Board announced new reporting requirements related to smart meter deployment and the application of time-of-use pricing. The information required to be reported by each distributor includes: the status of the deployment of smart meters in its service area; the integration of its meters and systems with the provincial meter data management and meter data repository ("MDM/R"); and its plans for implementing TOU and billing for RPP-eligible consumers. Grimsby Power Inc.'s deadline for implementing TOU rates has been set to December 31, 2011.
- Integration of meters and systems with the MDM/R including changes to business processes and systems has begun with a planned completion date of December 31, 2011.

Smart Meter Infrastructure

In this application Grimsby Power Inc. is applying for the recovery of costs for the deployment of smart meter infrastructure in its service area.

Grimsby Power Inc. is specifically requesting the following:

- A smart meter cost recovery rate rider of $1.66 per metered customer per month for the period January 2012 to December 2012. This rate rider will collect the difference between the smart meter adder collected from May 2006 to December 2011 and the revenue requirement related to smart meters deployed as of December 31, 2011.

- Approval to include smart meter capital to be deployed as of December 31, 2011 in the 2012 rate base that supports the 2012 revenue requirement and distribution rates which is the subject of this rate application.

- The smart meter cost recovery rate rider is to apply to all customer classes which paid the smart meter rate adder. Specifically residential, GS<50, and GS>50.

- Approval to include smart meter operation and maintenance expenses in the 2012 revenue requirement associated with smart meters deployed as of December 31, 2011.

- The elimination of the current smart meter funding adder of $1.99.

Stranded Meter Costs

Grimsby Power Inc. is applying for the recovery of costs associated with the stranded meter costs. Stranded meter costs arise as a result of electromechanical meters being taken out of service (as a result of the smart meter program) but not fully depreciated. Grimsby Power Inc. is specifically requesting the following:

- A stranded meter rate rider of $3.18 per metered customer per month for the period January 2012 to December 2012. This rate rider will collect the stranded meter costs of $400,564.
- The stranded meter rate rider is to apply to all customer classes which paid the smart meter rate adder. Specifically residential, GS<50, and GS>50.

DETAILED DESCRIPTIONS OF INITIATIVES WITHIN THE SMART METER PROGRAM

Annual Security Audit

With the mass deployment of AMI systems, security of the AMI network is critical to prevent utilities from becoming susceptible to new levels of potential security breaches and to ensure customer privacy and acceptance of the network. By installing network infrastructure in the field, there is now a requirement for additional security measures in order to ensure that utility data and equipment are kept secure from manipulation or other forms of control. As networks are deployed throughout North America, cyber security articles with reports of the potential for smart-grid hacking are becoming commonplace in the media. The minimum Functional Specification for an Advanced Metering Infrastructure (AMI) released in July 2007 identified the need for security within the AMI network - Section 2.11 Security and Authentication: "The AMI shall have security features to prevent unauthorized access to the AMI and meter data and to ensure authentication to all AMI elements." Some of the privacy and network security infrastructure concerns that have been raised include:

- Monitoring a consumer's usage
- Modifying one's own, or another consumer's usage
- Interrupting the power of one or more consumers

- Tampering with demand side management tools which can be controlled through smart meters.

For many Ontario LDCs, including Grimsby Power Inc., completing a security audit at a NERC, NIST or comparable level would be a cost-prohibitive exercise. Therefore, Grimsby Power Inc. joined a consortium of Ontario Util-Assist LDC customers in the issuance of the May 2011 “Smart Meter Network Security Audit Services” Request for Proposal. The request for proposals were evaluated by Util-Assist and the successful vendor was Bell-Wurldtech. The audit is currently ongoing.

Meter Data Management (MDM) System or Operational Data Store (ODS)

Grimsby Power Inc. fully supports the IESO MDM/R system and is committed to facilitating enrolment as quickly as possible with the MDM/R.

As Grimsby Power Inc. moved into the implementation of its AMI systems, a need was recognized for an application that supported full integration with the MDM/R and enabled our team to audit, validate, interact with and gain valuable business information from the wealth of meter data that was being collected by the MAS head-end system. The MAS system, while fully capable of collecting meter read data and forwarding that raw data to the MDM/R, does not provide all of the functionality necessary to operate the AMI and interpret and/or leverage the information it is providing in an educated and meaningful fashion.

NEPA, with Util-Assist’s (consulting firm) support, issued an RFP for an operational data store (ODS) in 2009. Following the RFP process, shortlisted vendors delivered software demonstrations and the subsequent evaluation lead to the selection of Harris as the preferred vendor with their MeterSense ODS application. The software is web-based and will be hosted by Harris following an ASP model. The Harris MeterSense product is a complete meter data management solution that stores, validates, and manages smart meter interval, and operational data as well as provides reporting capabilities and integration interfaces to CIS systems. Contract negotiations were completed and a signed contract was put in place in March 2010. The deployment of the ODS took place over several months coming into full functionality in July 2011.

The primary requirements and features of the operational data store (ODS) are:

- QA/Validation on the meter reads
- Meter event reporting (voltage alarms, tamper events, etc.)
- Reporting how long after installation meters first communicate their reads
- Dashboard views of percentage of meters installed and percentage of meters reporting
- Map based reports on meter communication paths
- Register and/or TOU read flows into CIS
- Long term data storage of register, interval, tamper, outage, and meter event data
- Support the most common methods of validation, editing, and estimating (VEE)

Business Process Redesign and Integration with the MDM/R

Throughout the first half of 2011, the Util-Assist training team delivered a series of education sessions covering the MDM/R design specifications, meter read data, VEE and other billing processes, and the design of a testing/cutover strategy. LDCs have widely recognized that a number of business processes, including new account setup, meter installations, meter changes, move-in/move-out and final billing all require scrutiny and procedural modifications to ensure that MDM/R integrations are optimized. Grimsby Power Inc.'s customer information system (CIS) is the SAP system and it is provided by Canadian Niagara Power (CNP) as a software as a service model. Grimsby Power has been working with CNP personnel on the integration of the MDM/R with the SAP CIS software. Currently Grimsby Power Inc. is following the IESO's processes to complete integration with the MDM/R.

System Changes

Grimsby Power Inc. uses the SAP Billing System hosted by Canadian Niagara Power. Grimsby Power Inc. expects the SAP system to be fully capable of supporting MDM/R integration and TOU billing within defined regulatory.

Transition to TOU Pricing

In mid-2010, the Ontario Government articulated an expectation that 1 million RPP customers would be billed using TOU pricing by the summer of 2011, rising to 3.6 million customers by June 2012. On June 24, 2011, the Ontario Energy Board issued a proposed determination regarding mandated time-of-use pricing for regulated price plan customers (Board File No. EB-2011-0218), suggesting that distributor-specific TOU dates would be the most appropriate approach, as it allows for the deadline to logically follow MDM/R enrolment activities.

Grimsby Power Inc. is confident that it will complete the transition to TOU pricing prior to the December 31, 2011 deadline.

Web Presentment

The Ministry of Energy and Infrastructure has indicated that electricity customers should ideally have web access to their consumption data with which to make informed decisions about future usage as part of a utility's rollout of TOU pricing. Accordingly, the SME Transition Committee formally requested a proposal from an established web presentment service provider, Whitecap

Canada Inc., as they are already providing an effective solution to several LDCs in Ontario. Preliminary investigations by Grimsby Power Inc. has identified the security features, ease of implementation, ease of use, existing integration with the provincial MDM/R, low cost-per-customer advantages, and the consistent user experience for customers as they relocate within Ontario as key benefits of the Whitecap portal solution. Although no formal discussions have been initiated with Whitecap, funds have been budgeted in Grimsby Power Inc. 2012 budget for the implementation of this or a similar solution.

Consumer Education Plan

Grimsby Power Inc. intends to leverage the significant development efforts undertaken by the Ministry of Energy to support LDC-specific communications tools and resources related to Time-of-Use (TOU) roll-out to electricity customers. In keeping with Grimsby Power Inc.'s mission statement Grimsby Power Inc. is currently planning a customer education and outreach campaign aligned with our time-of-use (TOU) pricing rollout. In the meantime, Grimsby Power Inc. plans to continue to keep customers informed about our smart meter project and TOU pricing through the corporate website and through articles in the local newspaper(s).

SMART METER RATE RIDER FOR COST RECOVERY

Smart Meter Costs

In this Application, Grimsby Power Inc. is seeking recovery of costs related to the smart meter infrastructure initiative installed from 2009 to 2010 and forecasted expenditures in 2011.

Table 9.9 below provides a summary of the smart meter initiative.

Table 9.9 Smart Meter Costs (Board Appendix 2-Q)

Year	Smart Meters Installed			Percentage	Account 1555		Account 1556
	Residential	GS < 50 kW	Other [1]	of applicable customers converted	Funding Adder Revenues Collected	Capital Expenditures	Operating Expenses
				%	$	$	$
2006					-$ 20,546		
2007					-$ 31,142		
2008					-$ 31,854		
2009	207	26		2.31%	-$ 32,126	$ 181,194	
2010	9,148	441		95.20%	-$ 84,325	$ 1,131,557	$ 46,430
2011	70	180		2.48%	-$ 193,499	$ 197,475	$ 225,880
Total	**9,425**	**647**		**100.00%**	**-$ 393,492**	**$ 1,510,225**	**$ 272,310**

Table 9.10 below provides a summary of 2009 & 2010 actual and forecast costs to 2011, followed by a brief analysis of the results.

Table 9.10 Summary of Smart Meter Costs

	2009	2010	YTD Actual	2011 Forecasted	Total Project Costs
Total Number of Smart Meters Installations to December 31, 2010	**233**	**9,589**	**9,822**	**274**	**10,096**
1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	50,991	1,123,979	1,174,970	177,475	1,352,445
1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	130,203	78	130,281	20,000	150,281
1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)					
1.4 WIDE AREA NETWORK (WAN)					
1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY		7,500	7,500		7,500
Total Capital Costs - All Smart Meters Installed	**181,194**	**1,131,557**	**1,312,751**	**197,475**	**1,510,225**
Capital Cost per Smart Meter Installed			**$ 133.65**		**$ 149.59**
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)		5,767	5,767		5,767
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)		36,596	36,596	82,620	119,216
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)			-		-
2.4 WIDE AREA NETWORK (WAN)			-		-
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY		4,067	4,067	143,260	147,327
Total O M & A Costs		**46,430**	**46,430**	**225,880**	**272,310**
O M & A Cost per Meter			**$ 4.73**		**$ 26.97**

The 2009 & 2010 actual costs above are taken from Grimsby Power Inc.'s financial records as at December 31, 2010. The Board Guideline G-2009-0002 Smart Meter Funding and Cost Recovery, states "when applying for recovery of smart meter costs, a distributor should ensure that all cost information has been audited, including the smart meter related deferral account balances" . The 2011 costs included in this rate application are forecasted and not auditable until Grimsby Power Inc.'s fiscal year end. The December 31, 2010 balances in the smart meter deferral accounts have been audited by Grimsby Power Inc.'s external auditors. The Auditors Report is provided in Appendix 9.1.

Grimsby Power Inc.'s smart meter infrastructure initiative does not contain any functionality beyond the minimum functionality adopted in O.Reg. 425/06. As a result all costs reported reflect only the minimum functionality required. Grimsby Power Inc. does not have a billing MDM/R system and intends to use only the Smart Meter Entity MDM/R system for billing Time of Use customers.

Capital Cost Analysis

Grimsby Power Inc. is forecasting that it will have all smart meters installed for Residential and GS<50 rate classes by the end of 2011. The average capital cost to install smart meter infrastructure per customer is $1,510,225 divided by 10,096 or $150 per customer. This is less than the estimated cost of $187 per customer.

OM&A Cost Analysis

The OM&A cost accumulated as at December 31, 2011 is forecasted to be $272,310. Since the system is not yet fully functional it is not possible to calculate a cost per meter as compared with the original estimates as was done for the Capital Cost Analysis above.

Smart Meter Cost Recovery Calculation

The incremental revenue requirement is calculated as indicated in Table 9.11 below:

Table 9.11 Smart Meter Revenue Requirement

	2006		2007		2008		2009		2010		2011	
Net Fixed Assets		$ -		$ -		$ -		$ 87,577		$ 720,834		$ 1,317,136
OM&A	$ -		$ -		$ -		$ -		$ 46,430		$225,880	
WCA	15%	$ -	15%	$ -	15%	$ -	15%	$ -	15%	$ 6,964	15%	$ 33,882
Rate Base		$ -		$ -		$ -		$ 87,577		$ 727,799		$ 1,351,018
Deemed ST Debt	4%	$ -	4%	$ -	4%	$ -	4%	$ 3,503	4%	$ 29,112	4%	$ 54,041
Deemed LT Debt	56%	$ -	56%	$ -	56%	$ -	56%	$ 49,043	56%	$ 407,567	56%	$ 756,570
Deemed Equity	40%	$ -	40%	$ -	40%	$ -	40%	$ 35,031	40%	$ 291,120	40%	$ 540,407
ST Interest	2.46%	$ -	2.46%	$ -	2.46%	$ -	2.46%	$ 86	2.46%	$ 716	2.46%	$ 1,329
LT Interest	5.97%	$ -	5.97%	$ -	5.97%	$ -	5.97%	$ 2,928	5.97%	$ 24,332	5.97%	$ 45,167
ROE	9.58%	$ -	9.58%	$ -	9.58%	$ -	9.58%	$ 3,356	9.58%	$ 27,889	9.58%	$ 51,771
		$ -		$ -		$ -		$ 6,370		$ 52,937		$ 98,268
OM&A		**$ -**		**$ -**		**$ -**				**$ 46,430**		**$ 225,880**
Amortization		$ -		$ -		$ -		$ 6,040		$ 50,865		$ 96,233
Grossed-up PILs		$ -		$ -		$ -		$ 1,452		$ 8,420		$ 14,231
Revenue Requirement		$ -		$ -		$ -		$ 13,862		$ 158,652		$ 434,612

The smart meter adder costs collected from customers since 2006 are noted in Table 9.12 below:

Table 9.12 Smart Meter Rate Adder Collected

Month	Opening Balance	SM Adder
May-06	$ -	-$ 227
Jun-06	-$ 227	-$ 2,229
Jul-06	-$ 2,456	-$ 2,552
Aug-06	-$ 5,009	-$ 2,556
Sep-06	-$ 7,565	-$ 2,567
Oct-06	-$ 10,132	-$ 2,736
Nov-06	-$ 12,868	-$ 2,393
Dec-06	-$ 15,261	-$ 5,285
Jan-07	-$ 20,546	-$ 2,756
Feb-07	-$ 23,302	-$ 2,607
Mar-07	-$ 25,908	-$ 2,419
Apr-07	-$ 28,328	-$ 2,457
May-07	-$ 30,784	-$ 2,573
Jun-07	-$ 33,357	-$ 2,576
Jul-07	-$ 35,933	-$ 2,664
Aug-07	-$ 38,597	-$ 2,576
Sep-07	-$ 41,173	-$ 2,693
Oct-07	-$ 43,866	-$ 2,497
Nov-07	-$ 46,363	-$ 2,731
Dec-07	-$ 49,094	-$ 2,595
Jan-08	-$ 51,689	-$ 2,965
Feb-08	-$ 54,654	-$ 2,519
Mar-08	-$ 57,173	-$ 2,518
Apr-08	-$ 59,691	-$ 2,594
May-08	-$ 62,286	-$ 2,696
Jun-08	-$ 64,982	-$ 2,836
Jul-08	-$ 67,818	-$ 2,602
Aug-08	-$ 70,420	-$ 2,643
Sep-08	-$ 73,063	-$ 2,783
Oct-08	-$ 75,846	-$ 5,314
Nov-08	-$ 81,160	$ 85
Dec-08	-$ 81,075	-$ 2,467
Jan-09	-$ 83,542	-$ 2,795
Feb-09	-$ 85,182	-$ 2,678
Mar-09	-$ 86,705	-$ 2,445
Apr-09	-$ 87,995	-$ 2,745
May-09	-$ 89,585	-$ 2,515
Jun-09	-$ 90,944	-$ 2,661
Jul-09	-$ 92,449	-$ 2,720
Aug-09	-$ 94,014	-$ 2,729
Sep-09	-$ 95,588	-$ 2,660
Oct-09	-$ 97,093	-$ 2,739
Nov-09	-$ 98,676	-$ 2,664
Dec-09	-$ 100,186	-$ 2,776
Jan-10	-$ 101,807	-$ 2,737
Feb-10	-$ 91,323	-$ 2,490
Mar-10	-$ 80,592	-$ 2,765
Apr-10	-$ 70,136	-$ 2,678
May-10	-$ 59,594	-$ 3,546
Jun-10	-$ 49,919	-$ 8,688
Jul-10	-$ 45,385	-$ 10,766
Aug-10	-$ 42,930	-$ 10,301
Sep-10	-$ 40,011	-$ 10,050
Oct-10	-$ 36,840	-$ 10,296
Nov-10	-$ 33,916	-$ 9,807
Dec-10	-$ 30,501	-$ 10,199
Jan-11	-$ 27,480	-$ 10,225
Feb-11	-$ 1,487	-$ 9,188
Mar-11	$ 25,543	-$ 11,477
Apr-11	$ 50,283	-$ 9,758
May-11	$ 76,744	-$ 11,403
Jun-11	$ 101,559	-$ 19,223
Jul-11	$ 118,553	-$ 21,424
Aug-11	$ 133,347	-$ 20,500
Sep-11	$ 149,065	-$ 20,000
Oct-11	$ 165,282	-$ 20,490
Nov-11	$ 181,010	-$ 19,515
Dec-11	$ 197,712	-$ 20,297
	Totals	
2006		-$ 20,546
2007		-$ 31,142
2008		-$ 31,854
2009		-$ 32,126
2010		-$ 84,325
2011		-$ 193,499
2006-2011		-$ 393,492

The calculation of the smart meter rate rider is shown in Table 9.13 below:

Table 9.13 Smart Meter Rate Rider Calculation

Description of Amount	Value
Revenue Requirement 2006	$ -
Revenue Requirement 2007	$ -
Revenue Requirement 2008	$ -
Revenue Requirement 2009	$ 13,862
Revenue Requirement 2010	$ 158,652
Revenue Requirement 2011	$ 434,612
Revenue Requirement Total	$ 607,125
Smart Meter Rate Adder	-$ 393,492
Carrying Cost	-$ 4,440
Smart Meter True-up	$ 209,193
Metered Customers	10,486
Rate Rider to Recover Smart Meter Costs	$ 1.66

Customer bill impacts arising from these smart meter rate adder/rider adjustments are an overall decrease of $0.33 ($1.99 minus $1.66) per metered customer per month for smart meter rate adder and rider charges.

Stranded Meter Costs

Grimsby Power Inc. is seeking disposition of its stranded meter costs. Grimsby Power Inc. is forecasting to have replaced 10,096 conventional meters with smart meters as at December 31, 2011. The net book value of the stranded conventional meters at December 31, 2010 was $400,564. Table 9.14 below outlines the detail to support this book value.

Table 9.14 Stranded Meter Treatment (Board Appendix 2-R)

Year	Notes	Gross Asset Value (A)	Accumulated Amortization (B)	Contributed Capital (Net of Amortization) (C)	Net Asset (D) = (A) - (B) - (C)	Proceeds on Disposition (E)	Residual Net Book Value (F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009					$ -		$ -
2010		$ 391,838			$ 391,838		$ 391,838
2011	(1)	$ 8,726			$ 8,726		$ 8,726
Total							$ 400,564

The calculation of the stranded meter rate rider is shown in Table 9.15 below:

Table 9.15 Stranded Meter Rate Rider Calculation

Description of Amount	Value
Stranded meters costs	$ 400,564
Metered Customers	10,486
Rate Rider to Recover Stranded Meter Costs	$ 3.18

Customer bill impacts arising from this stranded meter rate rider is an increase of $3.18 per metered customer per month.

Smart Meter Conclusion

Grimsby Power Inc. respectfully submits that the costs necessary to fulfill its obligations under the provincially mandated Smart Meter initiative have been prudently incurred in accordance with Board guidelines; the proposed riders are just and reasonable, the associated customer bill impacts are minimal; and it is appropriate that the Board approve the proposed recovery riders for implementation effective January 1, 2012.

Appendix 9.1 Auditors Report on Smart Meter Costs

Deloitte.

Deloitte & Touche LLP
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Canada

Tel: 905-315-6770
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Independent Auditor's Report

To the Ontario Energy Board (OEB)

At the request of Grimsby Power Incorporated, we have audited the 2010 and 2009 actual total capital costs and total OM&A costs included in the Table 9-20: Summary of Smart Meter Costs included in Exhibit 9, Tab 4, Schedule 3 (the "financial information"). This financial information has been prepared in accordance with the accounting guidelines established by the OEB.

Management's Responsibility for the Financial Information

Management is responsible for the preparation and fair presentation of the financial information in accordance with guidelines established by the OEB, and for such internal control as management determines is necessary to enable the preparation of the financial information that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the financial information based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance whether the financial information is free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial information. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial information, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial information in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial information.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial information presents fairly, in all material respects, the 2010 and 2009 actual total capital costs and total OM&A costs in accordance with the accounting guidelines established by the OEB.

Basis of Accounting and Restriction on Distribution

Without modifying our opinion, we draw attention that the financial information has been prepared in accordance with the accounting guidelines established by the OEB. As a result, the financial information may not be suitable for another purpose. Our report is intended solely for Grimsby Power Incorporated and the OEB and should not be distributed to parties other than Grimsby Power Incorporated or the OEB.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
May 5, 2011

Smart Meter Capital Cost and Operational Expense Data

Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	Asset Type	2009 Audited Actual	2010	Total
1.1.1 Smart Meter *may include new meters and modules, etc.*	Smart Meter	$ 11,202	$ 1,015,729	$ 1,026,931
1.1.2 Installation Cost *may include socket kits plus shipping, labour, benefits, vehicle, etc.*	Smart Meter	$ 39,789	$ 105,081	$ 144,870
1.1.3a Workforce Automation Hardware *may include fieldworker handhelds, barcode hardware, etc.*	Comp. Hard.		$ 3,169	$ 3,169
1.1.3b Workforce Automation Software *may include fieldworker handhelds, barcode hardware, etc.*	Comp. Soft.			$ -
Total Advanced Metering Communication Device (AMCD)		**$ 50,991**	**$ 1,123,979**	**$ 1,174,970**

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	Asset Type	2009 Audited Actual	2010	Total
1.2.1 Collectors	Smart Meter	$ 130,203	$ 78	$ 130,280
1.2.2 Repeaters *may include radio licence, etc.*	Smart Meter			$ -
1.2.3 Installation *may include meter seals and rings, collector computer hardware, etc.*	Smart Meter			$ -
Total Advanced Metering Regional Collector (AMRC) (includes LAN)		**$ 130,203**	**$ 78**	**$ 130,280**

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	Asset Type	2009 Audited Actual	2010	Total
1.3.1 Computer Hardware	Comp. Hard.			$ -
1.3.2 Computer Software	Comp. Soft.			$ -
1.3.3 Computer Software Licence & Installation (includes hardware & software) *may include AS/400 disc space, backup & recovery computer, UPS, etc*	Comp. Soft.			$ -
Total Advanced Metering Control Computer (AMCC)		**$ -**	**$ -**	**$ -**

1.4 WIDE AREA NETWORK (WAN)

2009	2010	Total

Smart Meter Capital Cost and Operational Expense Data

		2009 Audited Actual	2010	Total
1.4.1 Activation Fees	Tools & Equip			$ -
Total Wide Area Network (WAN)		**$ -**	**$ -**	**$ -**

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY

		2009 Audited Actual	2010	Total
1.5.1 Customer equipment (including repair of damaged equipment)	Other Equip.			$ -
1.5.2 AMI Interface to CIS	Comp. Soft.		$ 7,500	$ 7,500
1.5.3 Professional Fees	Comp. Soft.			$ -
1.5.4 Integration	Comp. Soft.			$ -
1.5.5 Program Management	Comp. Soft.			$ -
1.5.6 Other AMI Capital	Comp. Soft.			$ -
Total Other AMI Capital Costs Related To Minimum Functionality		**$ -**	**$ 7,500**	**$ 7,500**
Total Capital Costs		**$ 181,194**	**$ 1,131,557**	**$ 1,312,751**

O M & A

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)

	2009 Audited Actual	2010	Total
2.1.1 Maintenance *may include meter reverification costs, etc.*		$ 5,767	$ 5,767
Total Incremental AMI Operation Expenses	**$ -**	**$ 5,767**	**$ 5,767**

2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)

	2009	2010	Total
2.2.1 Maintenance		$ 36,596	$ 36,596
Total Advanced Metering Regional Collector (AMRC) (includes LAN)	**$ -**	**$ 36,596**	**$ 36,596**

2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)

	2009	2010	Total
2.3.1 Hardware Maintenance *may include server support, etc*			$ -
2.3.2 Software Maintenance *may include maintenance support, etc.*			$ -

Smart Meter Capital Cost and Operational Expense Data

Total Advanced Metering Control Computer (AMCC)	**$ -**	**$ -**	**$ -**

2.4 WIDE AREA NETWORK (WAN)

2.4.1 WIDE AREA NETWORK (WAN) *may include serial to Ethernet hardware, etc.*			$ -
Total Incremental Other Operation Expenses	**$ -**	**$ -**	**$ -**

2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY

2.5.1 Business Process Redesign			$ -
2.5.2 Customer Communication *may include project communication. etc.*			$ -
2.5.3 Program Management			$ -
2.5.4 Change Management *may include training, etc.*		$ 3,467	$ 3,467
2.5.5 Administration Cost			$ -
2.5.6 Other AMI Expenses		$ 600	$ 600
Total 2.5 Other AMI OM&A Costs Related To Minimum Functionality	**$ -**	**$ 4,067**	**$ 4,067**
Total O M & A Costs	**$ -**	**$ 46,430**	**$ 46,430**