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Newmarket-Tay Power Distribution Ltd.

VIA EMAIL & OVERNIGHT COURIER

July 20, 2010

Ontario Energy Board
PO Box 2319
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Newmarket-Tay Power Distribution Ltd. (Licence #ED-2007-0624) is filing a 2010 cost of service application for its Newmarket-Tay Service Areas as defined in the above-mentioned licence. This filing has been submitted to you via email as well as two hard copies delivered via courier.

Please contact us if any further information is required.

Yours truly,

Iain Clinton

Iain Clinton, CA
Chief Financial Officer

Phone: 905-953-8548 X2300
Email: iclinton@nmhydro.ca

Newmarket Tay Power

2010 EDR Application

EB-2009-0269

Submitted 21st July 2010

Newmarket Tay Power
590 Steven Court
Newmarket
Ontario L3Y 6Z2

Exhibit 1:

ADMINISTRATIVE DOCUMENTS

Exhibit 1: Administrative Documents

Tab 1 (of 4): Application Summary

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LEGAL APPLICATION

ONTARIO ENERGY BOARD

IN THE MATTER OF T*he Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Sched. B)

AND IN THE MATTER OF an application by Newmarket-Tay Power Distribution Ltd. for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates and other service charges for the distribution of electricity and related matters.

APPLICATION

Introduction

1) The Applicant is Newmarket-Tay Power Distribution Ltd. ("The Applicant"). The Applicant is a licensed electricity distributor operating pursuant to license ED-2007-0624. The Applicant distributes electricity to approximately 32,000 customers in the Towns of Newmarket and Tay.

2) The Applicant hereby applies to the Ontario Energy Board (the "Board") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act*, 1998, as amended, (the "OEB Act") for approval of its proposed distribution rates and other charges. A list of requested approvals is set out in Exhibit 1, Tab 1, Schedule 3.

3) The Applicant has prepared this Application in accordance with the filing requirements issued by the Board on May 27, 2009 as Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications*, in particular with

"Filing requirements for electricity transmission and distribution companies' cost of service rate applications based on a forward test year".

Relief Sought

4) The Applicant requests that the Board approve the Schedule of Rates and Charges identified in this application Exhibit 8, Tab 9, Schedule 2, Tab 1.

5) Specifically, The Applicant hereby applies for an order or orders granting approval of:

a. its forecasted 2010 distribution base revenue requirement of $17,468,865;

b. specific distribution service charges of $846,361;

c. the dispersal of Regulatory Asset, deferral and variance accounts;

d. the proposed clearance of the following deferral and variance account balances as audited as at December 31, 2008, plus interest calculated until April 31, 2010:

- 1518 – RCVA Retail
- 1548 – RCVA STR
- 1556 – Smart Meter OM&A Variance Account
- 1562 – Deferred PILS
- 1580 – RSVA WMS
- 1582 – RSVA One-Time
- 1584 – RSVA NW
- 1586 – RSVA CN
- 1588 – RSVA Power
- 1588 – RSVA Power – Sub Account Global Adjustment
- 1590 – Recovery of Regulatory Asset Balance;

e. a deferral account to use for costs associated with the Green Energy Act;

f. a deferral account to use for cost associated with Low-Income Energy Assistance Program (LEAP);

g. an Interval Meter kW rate to convert hourly peaks to 15 minute peaks; and

h. a deferral account to record costs associated with the late payment charges class action.

6) As indicated in the Applicant's pre-filed evidence, its 2010 base revenue requirement is forecast to be $17,468,865 million. Based on current distribution rates and forecasted load, the Applicant forecasts a 2010 revenue deficiency of $2,617,276.

7) The 2010 distribution rates proposed by the Applicant will result in overall bill impact as follows:

Class	**Usage**	**Increase Newmarket**	**Increase Tay**
	Kwh	%	%
Residential	800	4.80	-2.17
General Service < 50	2,000	5.84	8.58
General Service > 50	200,000	3.84	0.71
Unmetered Scattered Load	200	-10.81	9.30
Sentinel Lighting	1	2.72	10.04
Street Lighting	1	1.69	26.25

8) This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

9) The Applicant requests that, pursuant to Section 34.01 of the Board's *Rules of Practice and Procedure*, this proceeding be conducted by way of written hearing.

10) The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

Mr. Iain Clinton, C.A.
Chief Financial Officer

Newmarket-Tay Power Distribution Ltd.
590 Steven Court
Newmarket, ON L3Y 6Z2

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Fax: 905.895.8931
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Counsel for Newmarket-Tay Power Distribution Ltd.:

Mr. Andrew Taylor
Andrew Taylor, Energy Law

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Email: ataylor@energyboutique.ca

DATED at Newmarket, Ontario, July 5, 2010

Iain Clinton

I. Clinton, Chief Financial Officer, Newmarket-Tay Power Distribution Ltd.

SUMMARY OF THE APPLICATION

Newmarket Tay Power Distribution Ltd. ("the Applicant") is submitting a cost of service rate application based on a 2010 test year for 2010 electricity distribution rates and other specific charges.

In preparing this Application, the Applicant has relied on the Board's Filing Requirements for Transmission and Distribution Applications, relevant portions of the Board's 2006 Electricity Distribution Rate Handbook and guidelines issued by the Board for treatment of specific items such as smart metering and deferral and variance accounts.

This Application does not include costs associated with any CDM programs, OPA projects or Green Energy Act costs.

Introduction

The Applicant is an electricity distributor licensed by the Ontario Energy Board. In accordance with its Distribution License ED-2007-0624, the Applicant provides electricity distribution services in the Town of Newmarket and certain parts of the Township of Tay.

The Applicant is 93% owned by Newmarket Hydro Holdings Inc which is a wholly-owned subsidiary of The Town of Newmarket, and 7 % owned by Tay Holding Company Inc which is wholly-owned by the Township of Tay. The Applicant is the result of an OEB approved merger of Newmarket Hydro Ltd and Tay Power Distribution Ltd on May 1, 2007.

The Applicant currently serves approximately 32,000 electricity distribution customers across its two service areas.

Harmonization

The Applicant presently administers two Board-approved Tariffs of Rates and Charges.

The Applicant has one set of rates for Newmarket. These rates were approved in its 2008 cost of service application (EB-2007-0776).

The Applicant has another set of rates approved for the Tay Service are as part of the 2006 EDR. As part of the settlement process in its last rebasing application EB-2007-0776, the Applicant agreed to return by 2010 or 2011 with a harmonized rate application for the two service areas.

In order to present a harmonized application, the applicant has calculated costs and usage for each individual service area and then combined the two results to derive harmonized rates.

Description of the Applicant's Service Areas

The two communities the Applicant serves have distinct characteristics; Newmarket is a dense urban utility, with some large automotive manufacturing and an expanding population and distribution system. Tay's service area contains mostly residential customers located in a mix of light urban, seasonal, and rural areas, with stagnant population growth.

The Applicant is responsible for maintaining distribution and infrastructure assets deployed over 41 square kilometers (including 243 kilometers of overhead lines and 416 kilometers of underground lines) within the Newmarket service area and over 47 square kilometers (including 342 kilometers of overhead lines and 14 kilometers of underground lines) within the Tay service area.

Newmarket's customer growth since 2003 to 2010 has increased 16.5 %; whereas Tay's customer growth since 2003 has only been 6%.

While Tay's service area covers more square footage than does Newmarket service area however Tay has only 1/7th of Newmarket's population.

Newmarket is located in the Northern Part of York Region, while Tay is located on the shores of Georgian Bay in North Simcoe County. The two service areas are not contiguous requiring the Applicant to maintained two offices: one in Newmarket and one in Tay.

Newmarket is not embedded while Tay is embedded off Hydro One's Waubaushene TS.

2010 Application for Rates and Charges

The Applicant is applying for distribution rates and charges to recover its forecast aggregate revenue requirement for the 2010 test year. The information provided in all of the following exhibits sets out the components of the revenue requirement, deferral accounts, the methodologies, information and assumptions the applicant used to determine the requested rates and specific user charges.

The following table summarizes the components of the Applicant's 2010 test year revenue requirement and calculated deficiency.

Newmarket-Tay Power Distribution Ltd. Summary of Revenue Requirement Deficiency Test Year 2010		
Distribution Revenues at Current rates		**14,851,590**
Less Expenses		
	Amortization	4,525,690
	Administration	2,798,398
	System Operation and Maintenance	2,560,224
	Customer Billing and Collecting	2,331,264
	Community Relations	76,332
	Interest Deemed	2,164,584
	Property and Capital Taxes	173,946
		(14,630,438)
Other Income/Charges		**846,361**
Less Regulated Equity		**(2,530,701)**
Less PILs		**(1,154,088)**
Revenue Deficiency		**(2,617,276)**

Cost of capital from Exhibit 5 $4, 695,285; (composed of $2,530,701 from the Return on Equity and $2,164,584 in Deemed Interest).

A more detailed calculation on the 2010 revenue deficiency is provided in Exhibits 5 and 6

The forecasted overall revenue requirement for 2010 is $18,315,226. A large driver of the revenue requirement is the amount needed for certain mandated projects; Smart Meters and Time of Use pricing, Holland TS and the VIVA infrastructure project, which are outside the control of the Applicant. The cost of capital component including PILs for these projects is $1.4 million of the revenue requirement.

Amortization	$	555,172.72
Cost of Capital	$	662,319.97
PIL's component	$	167,991.68
Lost Interest Revenue	$	45,302.32
Total	$	1,430,786.69

The largest of the mandated projects is the Smart Meter / Time of Use pricing project ("TOU"). The Applicant has been named in provincial legislation as a priority installation utility under Ontario Regulation 428/06 and is permitted to carry out the functions of the Smart Meter Entity, under O. Reg. 233/08, for all its customers with a smart meter.

The Applicant began its smart meter deployment for all residential customers in the Spring of 2007. By the end of 2008, all eligible residential customers in Newmarket had a smart meter installed. The Applicant began integration and testing with the provincial MDMR in April of 2007. Meter registration, and data transmission were completed by May. Billing data acquisition from the provincial MDM/R for 250 RPP-eligible customers began in April 2008 to allow the Applicant to comprehensively test MDMR integration. Using a contracted MDMR service, the Applicant has shifted all eligible residential customers in Newmarket to TOU pricing on a billing by billing cycle basis. The Applicant successfully implemented changes in business processes and CIS to implement TOU billing. TOU data is available on the Applicant's website for all customers with a smart meter.

The total request for Smart Meter / Time of Use funding; including OM&A, is summarized as follows:

Smart Meters/TOU Pricing		
Effect on the 2010 Revenue Requirement		
Amortization	$	423,872.00
Cost of Capital	$	396,244.03
PIL's component	$	100,503.84
Lost Interest Revenue	$	27,102.88
OM&A	$	372,000.00
Total	$	1,319,722.75

The revenue requirements for the Holland TS and the Viva Infrastructure projects are $328,081 and $154,982 respectively.

Further explanation of these projects can be found in Exhibit 2.

Rate Base Exhibit 2

The Deemed Interest and Equity components ("cost of capital") are calculated from the Applicant's Rate Base and in total make up $4,695,285 of the Revenue Requirement. The Applicant's Rate Base is forecasted to be $64,230,978 in the test year. The following table summarizes the Applicant's historical rate base for 2006, 2007, 2008 and 2009 and forecasted amount for 2010.

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecasted
Average Net Fixed Assets	42,730,767	44,913,584	48,519,603	50,777,505	54,500,163
Working Capital Allowance	9,014,925	9,136,841	9,099,621	9,202,468	9,730,814
Rate Base	51,745,692	54,050,425	57,619,224	59,979,973	64,230,977

The 2010 Rate Base of $64,230,978 multiplied by the weighted average cost of capital from Exhibit 5 of 7.31 % equals $4, 695,285; (composed of Equity $2,530,701 from the Return on Equity and Deemed Interest of $2,164,584).

The 2010 increase in net fixed assets is largely due to the additional fixed assets that were required either by the government, system reliability or customer demand and therefore were beyond the control of the Applicant. The main drivers of the capital spending increase are three major capital projects that have been mandated by government bodies. These three projects, Holland TS, Smart Meters and the VIVA infrastructure project, account for over 50% ($12.7M) of the capital additions required since 2006, and represent $4.2 M of capital asset expenditures in 2010.

Holland TS

Holland TS was undertaken in order to improve the supply of electricity to the customers in northern York Region. The Ontario Energy Board directed Hydro One, the Applicant and other distributors to construct and connect their systems to Holland TS This directive was initiated under proceeding number EB-2005-0315.

Smart Meters

In 2006, the Applicant embarked on an accelerated implementation of the government's Smart Meter program and became a industry leader and major contributor to the design and development of this province wide endeavor. The Provincial government (through Ontario Regulations 428/06, 427/06 and 426/06) outlined the requirements of the "smart meter" initiative and the Applicant's service area was identified as a priority implementation area.

Viva Infrastructure Project

In conjunction with its Places to Grow and Move Ontario initiatives, the Government of Ontario through its transportation agency (MetroLinx) has identified Newmarket as a Mobility Hub in the province's Regional Transportation Plan. As part of the plan The Regional Municipality of York (the "Region") in conjunction with MetroLinx has commenced a major Infrastructure Project to improve rapid transportation on Yonge St. and several arteries that connect to it

The overall effect of these projects on the Applicant's 2010 revenue requirement is:

Amortization	$	555,172.72
Cost of Capital	$	662,319.97
PIL's component	$	167,991.68
Lost Interest Revenue	$	45,302.32
Total	$	1,430,786.69

Working capital allowance

The $528,000 increase in working capital allowance in the test year is due to a $2,400,000 total increase in the cost of power and a $1,200,000 increase in the OM&A. The cost of power increase is attributed to increases in the commodity wholesale rate, wholesale transmission network rate, and wholesale transmission connection rate. The increase in OM&A is attributable to Smart Meter operating costs, an insurance increase, tree trimming in the Tay service area, additional staff to deal with asset management and electrical safety standards, and the regulatory cost of service filing. Detailed descriptions of the increases in OMA are provided in Exhibit 4.

Overall increase in the Cost of Capital

The most recent rates for the former Tay Hydro (2006 EDR) and Newmarket Hydro (2008) were based on a weighted average cost of capital of 8.57 % for Tay and 7.13 % for Newmarket. In the current rate application, the weighted cost of capital is 7.31% an increase of 0.002% over the combined weighted cost of capital of the two former utilities. This slightly higher cost of capital produces s a significant impact on the revenue requirement when it is applied to the large increase in rate base

The increase in rate base since the last rate application have been significant in both service areas (Newmarket's increase over 2008 is $6,398,916 or 12%; Tay's increase over it's 2006 EDR is $690,914 or 20%). These increases produce a $545,000 increase in the cost of capital

	Rate Base		
	2006 EDR	2008	2010 Test Year
Newmarket	-	53,598,720	59,997,636
Tay	3,542,427	-	4,233,341
Total	3,542,427	53,598,720	64,230,977

Revenues Exhibit 3

The Applicant has experienced a significant decrease in its large customer class with the loss of four large customers (including its largest customer) that generated over $380,000 in annual distribution revenue. This loss was offset by 1,200 new connections in the residential class in the Newmarket area over the past two years, as well as additional new commercial customer connections. Therefore, since 2008, there has only been a marginal increase in total distribution revenues as indicated by the table below

	2007	2008	2009 Bridge (12 mons @ 2009 rates)	2010 Test (12 mons @ 2009 Rates)	2010 Test (12 mons @ 2010 Rates)
Residential	7,996,556	8,104,474	8,315,769	8,415,172	9,926,666
GS<50	2,348,127	2,361,827	2,361,373	2,373,704	2,792,019
USL	29,702	29,951	25,033	25,033	29,445
GS>50	4,164,664	4,214,383	3,844,240	3,730,931	4,388,428
Street Lights	60,346	61,738	288,727	292,715	315,800
Sentinel Lights	12,035	12,035	14,597	14,038	16,508
Total	$14,611,430	$14,784,408	$ 14,849,739	$ 14,851,593	$ 17,468,866

The Applicant based its 2010 calculations on a weather normalization load forecast completed by Elenchus and two Navigant studies that show TOU pricing does not affect conservation.

A more detailed explanation of distribution revenues for the 2010 test year is provided in Exhibit 3.

A more detailed explanation of distribution revenues for the 20110 test year is provided in Exhibit 3.

Specific Service Charges

The Applicant proposes to recover $846,361 in other revenues for the 2010 test year. This amount represents a decrease of $157,000 or a 16% reduction from the 2008 amounts. Actuals from 2008 to the 2010 forecast are presented in the table below:

Account Name	US of A	2008 Actual	2009 Actual	2010 Test (Current Rates)	2010 Test (Proposed Rates)
SSS Administration Charge	4080	(106,178)	(107,998)	(111,441)	(111,441)
Retail Service Revenues	4082	(47,714)	(47,085)	(46,950)	(46,950)
STR Revenues	4084	(1,511)	(4,249)	(1,565)	(1,565)
Revenue-Rentals	4210	(120,510)	(124,227)	(120,510)	(120,510)
Revenue-Late Payment Charges	4225	(181,345)	(214,538)	(194,504)	(194,504)
Specific Service Charges	4235	(325,108)	(319,007)	(319,016)	(366,596)
Revenue-Sale of Scrap Metals	4325	(10,795)	(11,490)	(4,795)	(4,795)
Gain on Sale of Assets	4355	(750)	(4,561)	0	0
Loss on Sale of Assets	4360	0	995	0	0
Revenue-Miscellaneous	4390	(26,784)	(9,095)	0	0
Interest Earned	4405	(182,785)	(88,647)	0	0
Grand Total Other Revenue		(1,003,479)	(929,902)	(798,781)	(846,361)

The primary driver of this decrease is bank interest revenues which are expected to decrease from $182,000 in 2008 to $0 in the test year. The applicant has incurred a significant investment in its net fixed assets as set out in Exhibit 2, which has significantly diminished its cash balances. Also where interest rates paid on its deposits have decreased, the Applicant achieves an interest rate of Canadian Business prime less 1.75 on outstanding cash balances. The forecasted interest rate for the 2010 test year is 0.5%.

The Applicant is requesting the standard Ontario Energy Board approved service rates with the exception of the Account Setup Charge, Collection of Account Charge – No Disconnection and Disconnect Reconnect at Meter During Regular Hours. With each of the three service rates, the Applicant contracts the field visit through third party providers at reduced costs. The Applicant used the model developed for the 2006 EDR to calculate rates that include the contract cost rather than the Applicant's labour cost of the field visit.

A more detailed explanation of other revenue and specific charges for the 2010 test year is provided in Exhibit 3.

Operating Costs Exhibit 4

The Applicant's operations, maintenance, and administration (OM&A) costs are forecasted to be $7,766,218 in 2010, as illustrated by the following table:

		2008	2009	Test Year Forecasted 2010
Operations and maintenance		1,831,140	2,208,026	2,560,224
Billing and Collecting		1,750,464	1,852,686	2,331,264
Administrative		2,374,534	2,442,373	2,798,398
Community Relations		72,007	63,202	76,332
Total		6,028,145	6,566,287	7,766,218
Dollar variance from previous year			538,142	1,199,931
Percent change from previous year			8.93%	18.27%
Percent Change Test year vs. 2008				28.83%
Average per period			14.42%	14.42%

The main cost drivers of these for 2009 and 2010 increases are:

2009

The main reason for the OM&A increase in 2009 is that the Applicant reassigned its line men from capital projects back to preventive maintenance programs. The Applicant over the past three years has undertaken several large capital projects including government mandated capital projects as described in Exhibit 2. The Applicant has determined that it is more efficient to outsource large capital projects to third parties and focus the Applicant's staff on maintenance and certain smaller capital projects. The Applicant has returned to its historical allocation of resources by assigning 55% to 60% of its available labour time to maintenance projects from the recent allocation using a 50/50 split between capital and maintenance. In the Newmarket service area, using 2002 and 2003 operating costs as a base; the 2010 forecasted operating costs represent an annual increase of 5 % since 2002 and 2003. An increase of 5% per annum is consistent with the Applicant's customer growth and the negotiated wage increases over the same period.

2010

The main drivers for the 2010 increase in OM&A (other than the wage increases on existing payroll) are summarized in the table below:

Smart meter OM&A costs	$372,000
Regulatory Rate filing costs	$150,000
Increase in Insurance costs	$60,000
New Engineering staff	$135,000
Total	$717,000

These costs have originated from conditions outside the control of the Applicant. The smart meter costs relate to annual operating costs for smart meters and TOU billing. Regulatory costs relate to this cost of service application. Increased insurance costs relate to the 2010 industry wide increase in the actual insurance premiums. A new engineer is needed to comply with increased operational requirements for collecting and managing asset management data and ensuring compliance with all Electrical Safety Authority regulations. A greater explanation of the listed variances is provided in Exhibit 4.

If the these non-discretionary expenditures are removed from the forecast 2010 costs, the increases proposed for the test year are considerably lower as shown in the table below:

		Actuals 2008	Actuals 2009	Test Year Forecasted 2010
Operations and maintenance		1,831,140	2,208,026	2,425,224
Billing and Collecting		1,750,464	1,852,686	1,959,264
Administrative		2,374,534	2,442,373	2,588,398
Community Relations		72,007	63,202	76,332
Total		6,028,145	6,566,287	7,049,218
Dollar variance from previous year			538,142	482,931
Percent change from previous year			8.93%	7.35%
Percent change test year vs. 2008				16.94%
Average for period			8.47%	8.47%

Cost of Capital Exhibit 5

The Applicants Cost of Capital in the 2010 test year has been calculated in accordance with the Ontario Energy Board's Cost of Capital provisions.

The proposed capital structure and cost of capital is summarized in the following table:

Capitalization/Cost of Capital				
Particulars	**Capitalization Ratio**		**Cost Rate**	**Return**
Application				
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$35,969,347	5.87%	$2,111,401
Short-term Debt	4.00%	$2,569,239	2.07%	$53,183
Total Debt	60.00%	$38,538,587	5.62%	$2,164,584
Equity				
Common Equity	40.00%	$25,692,391	9.85%	$2,530,701
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$25,692,391	9.85%	$2,530,701
Total	100%	$64,230,978	7.31%	$4,695,284

Full details of the Applicants Cost of Capital are presented in Exhibit 5.

Cost Allocation Exhibit 7

To support the 2010 cost of service filing, the Applicant has developed a single cost allocation model that combines the independent Newmarket and Tay models using 2010 Test Year forecast costs, throughout, other input values and proposed rates.

As demonstrated in the table below, all of the allocations are within the Board-approved ranges for each customer class.

Customer Class	Range	Ratio
Residential	85% - 115%	90.43%
GS<50	80% - 120%	91.27%
GS>50	80% - 180%	143.22%
Unmetered Scattered Load	80% - 120%	89.79%
Street Lighting	70% - 120%	113.49%
Sentinel Lighting	70% - 120%	99.38%

Allocation of Distribution Costs to the Street Light Class

As part of the rate harmonization, the Applicant is proposing a change to the methodology used for allocating costs to the street light class. This change is required to provide a proper allocation of costs to rate classes that would better reflect the principle of cost causality given the configuration of the combined distribution system.

The Applicant has been concerned that the methodology embedded in the 2006 CAR-IF model over-allocates costs to the street light class. The 2006 CAR-IF methodology assumes that each street light connection point is the equivalent of a single residential home and allocates costs accordingly. This simplifying assumption is not supported by the cost analysis subsequently conducted by the Applicant based on the configuration of the Applicant's distribution system.

The point of demarcation between the Applicant's distribution system and the street lighting is at the base of the streetlight pole in underground areas and the streetlight bracket in overhead areas. The conductors in the streetlight pole (in underground systems) and the street light bracket (in overhead systems) are not part of the Applicant's distribution system. As such, the number of street light connections is the same as the number of lights in the Applicant's service area. Based on this configuration, the cost to provide the distribution of electricity to a single street light is actually about 25% of the cost of servicing a residential home. The details of this analysis are contained in Exhibit 7, Tab 2, Schedule 3.

Details of the Applicants cost allocation calculations and results are in Exhibit 7.

Rate Design Exhibit 8

Bill impacts

The total bill impacts (including commodity charges) of the 2010 proposed distribution rates by service area are summarized in the table below:

Class	Usage	Increase/Decrease Newmarket	Increase/Decrease Tay
	Kwh	%	%
Residential	800	4.93	-2.05
General Service < 50	2,000	5.89	2.59
General Service > 50	200,000	3.72	0.58
Unmetered Scattered Load	200	-10.81	9.30
Sentinel Lighting		2.72	10.04
Street Lighting		1.69	26.25

Details of the Applicants Revenue Requirement, Rate Design and Bill Impacts are in Exhibit 8.

Deferral Accounts Exhibit 9

The Applicant maintains wholesale and retail settlement processes and variance accounts for each of the service areas, Newmarket and Tay.

The Applicant is proposing the following disposition of deferral and variance account balances as at March 31, 2010.

1) 1508 - Other Regulatory Assets totaling a debit/recovery balance of $51,880
2) 1518 - Retail Cost Variance totaling a credit/refund balance of ($611)
3) 1525 – Misc. Deferred Debits totaling a debit/recovery balance of $2,357
4) 1548 - Retail Cost Variance STR totaling a debit/recovery balance of $12,395
5) 1550 - Low Voltage Variance totaling a credit/refund balance of ($40,478)
6) 1555 - Smart Meter OM&A totaling a debit/recovery balance of $235,886
7) 1556 – Smart Meter OM&A totaling a debit/recovery balance of $882,631
8) 1562 – PILS totaling a debit/recovery balance of $443,717
9) 1563 – PILS Contra totaling a credit/refund balance of ($443,717)
10) 1580 – RSVA-Whisle Market Serv totaling a credit/refund balance of ($327,313)
11) 1582 – RSVA-One Time Charges totaling a debit/recovery balance of $26,390
12) 1584 – RSVA Trans Network totaling a debit/recovery balance of $40,936
13) 1586 – RSVA-Trans Connection totaling a credit/refund balance of ($259,111)
14) 1588 – RSVA-Power totaling a debit/recovery balance of $1,045,409
15) 1590 – Approved Reg. Assets totaling a credit/refund balance of ($929,810)
16) 1595 – Approved Reg. Assets totaling a debit/recovery balance of $996,037
17) LRAM – Approved Reg. Asset totaling a debit/recovery balance of $252,908

Detail information on the Applicant's Deferral accounts are presented in Exhibit 9.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0776

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 Newmarket-Tay Power Distribution Ltd. for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity within its Newmarket Service Area, as of the date of the Ontario Energy Board's Rate Order.

BEFORE: Paul Vlahos
Presiding Member

Cynthia Chaplin
Member

DECISION AND ORDER

Newmarket – Tay Power Distribution Limited ("Newmarket" or the "Applicant") filed an application with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act*, *1998*, seeking approval for changes to the rates that Newmarket charges for electricity distribution within its Newmarket Service Area, to be effective as of the date of the Ontario Energy Board's Rate Order. The application was received on July 4, 2008 and the Board has assigned the application File Number EB-2007-0776.

The Proceeding

The Board issued a Notice of Application and Hearing on July 21, 2008.

Energy Probe Research Foundation ("Energy Probe"), the School Energy Coalition ("SEC") and the Vulnerable Energy Consumers Coalition ("VECC") were granted intervenor status in this proceeding.

As part of its application, Newmarket requested that the Board immediately approve on an interim basis its proposal to revise and reduce the Applicant's Retail Transmission Network Service and Connection rates. On August 19, 2008, the Board issued its Decision and Procedural Order No. 1 in which it ordered that, with the exception of Newmarket's Retail Transmission Service Network and Connection rates for the Newmarket Service Area, the current rates be declared interim, effective on August 19, 2008. In addition, it ordered that the Retail Transmission Service Network and Connection rates proposed by the Applicant be approved on an interim basis, effective August 19, 2008.

Interrogatories from Board staff and intervenors were filed on September 12, 2008 and responses were to have been filed by the Applicant by October 3, 2008. The responses were filed on December 23, 2008. Procedural Order No. 2 was issued on January 30, 2009 in which the Board scheduled a Technical Conference for March 17, 2009 and ordered that a Settlement Conference would follow immediately afterward. The Settlement Conference was held on March 17^{th} and 18^{th}.

On April 9, 2009, Newmarket filed a proposed Settlement Agreement with the Board (the "Agreement") which represents a complete settlement of all of the issues by the parties.

Findings

The Board has examined the Agreement and accepts the terms of the Agreement as filed by the parties and the impact on the rates charged by the Applicant in its Newmarket Service Area, with the following comments. The Board reminds parties that terms contained in a settlement agreement do not create a precedent for the Board. In particular, with respect to Smart Meters, the Board refers the Applicant to the Board's Guideline G-2008-0002, issued on October 22, 2008, in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors. The Board also notes that this settlement agreement applies to only the rates for the Newmarket Service Area and the rates for the Applicant's Tay Service Area remain unchanged from the Board's Decision issued April 12, 2007 (EB-2007-0578).

For completeness of the regulated charges, the Board has included in the Tariff of Rates and Charges the charges pertaining to services provided to retailers or consumers regarding the supply of competitive electricity, which are referenced in Chapter 12 of the 2006 Electricity Distribution Rate Handbook.

The Board commends all the parties on achieving settlement of all the issues.

The Board has prepared a draft Tariff of Rates and Charges (Appendix A) that reflects the Agreement. The new distribution rates for the Newmarket Service Area will be effective May 1, 2009.

THE BOARD ORDERS THAT:

1. Newmarket shall review the draft Tariff of Rates and Charges set out in Appendix A. Newmarket shall file with the Board within seven calendar days of the date of this Decision and Order a written confirmation of the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information.

2. If the Board does not receive a submission from Newmarket to the effect that inaccuracies were found or information was missing pursuant to item 1 above, the draft Tariff of Rates and Charges set out in Appendix A will become final, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2009. The Tariff of Rates and Charges shall supersede all previous distribution rate schedules approved by the Board for Newmarket – Tay Power Distribution Ltd., and is final in all respects.

3. If the Board receives a submission by Newmarket to the effect that inaccuracies were found or information was missing pursuant to item 1 above, the Board will consider the submission of Newmarket and will issue a final Tariff of Rates and Charges.

4. Newmarket shall notify customers within its Newmarket Service Area of the rate changes no later than with the first bill reflecting the new rates.

Cost Awards

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

Energy Probe, SEC and VECC shall file with the Board and forward to the Applicant their respective cost claims within 21 days from the date of this Decision.

Newmarket shall file with the Board and forward to Energy Probe, SEC and VECC any objections to the claimed costs within 28 days from the date of this Decision.

Energy Probe, SEC and VECC shall file with the Board and forward to Newmarket any responses to any objections for cost claims within 35 days of the date of this Decision.

Newmarket shall pay the cost claims of the intervenors awarded by the Board upon receipt of the Board's Decision on Cost Awards.

Newmarket shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number EB-2007-0776**,** and be made through the Board's web portal at www.errr.oeb.gov.on.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.oeb.gov.on.ca. If the web portal is not available you may e-mail your documents to the attention of the Board Secretary at BoardSec@oeb.gov.on.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's Practice Directions on Cost Awards.

DATED at Toronto, April 23, 2009

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

To the Decision and Order

Newmarket – Tay Power Distribution Ltd.

EB-2007-0776

April 23, 2009

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0776
EB-2007-0578

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to a service which is less than 50 kW supplied to single-family dwelling units that is for domestic or household purposes, including seasonal occupancy. At the distributor'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.

General Service Less Than 50 kW
This classification refers to any service supplied to premises other than those designated as Residential and whose average monthly maximum demand over the past twelve months is less than 50 kW. This includes multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered). For new customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer.

General Service 50 to 4,999 kW
This classification refers to all non-residential customers whose average monthly maximum demand used for billing purposes over the past twelve months is equal to or greater than 50 kW but less than 5,000 kW. For new customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer.

Unmetered Scattered Load
This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. The distributor will not install any new sentinel lights.

Street Lighting
All services supplied to street lighting equipment owned by or operated for the Town of Newmarket, Township of Tay, the Town of East Gwillimbury or the Province of Ontario shall be classified as Street Lighting Service. This classification refers to roadway and sidewalk lighting operations, controlled by photoelectric 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.

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0776
EB-2007-0578

Newmarket Service Area
Per EB-2007-0776 Decision

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.06
Service Charge Tax Change Rate Rider – effective until April 30, 2010	$	(0.01)
Distribution Volumetric Rate	$/kWh	0.0136
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kWh	0.0025
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.82
Service Charge Tax Change Rate Rider – effective until April 30, 2010	$	(0.03)
Distribution Volumetric Rate	$/kWh	0.0159
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kWh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	157.81
Service Charge Tax Change Rate Rider – effective until April 30, 2010	$	(0.16)
Distribution Volumetric Rate for non-interval metered customers	$/kW	4.3252
Distribution Volumetric Rate for interval metered customers	$/kW	4.4462
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kW	0.1401
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/ kW	(0.0043)
Retail Transmission Rate – Network Service Rate	$/kW	1.9923
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7038
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	16.41
Service Charge Tax Change Rate Rider – effective until April 30, 2010	$	(0.02)
Distribution Volumetric Rate	$/kWh	0.0138
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kWh	0.0092
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0776
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Service Charge (per connection)	$	1.76
Distribution Volumetric Rate	$/kW	6.7259
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kW	0.5879
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/ kW	(0.0067)
Retail Transmission Rate – Network Service Rate	$/kW	1.5101
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3447
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.76
Distribution Volumetric Rate	$/kW	8.7412
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kW	0.1907
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/ kW	(0.0087)
Retail Transmission Rate – Network Service Rate	$/kW	1.5025
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3172
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	8.50
Statement of account	$	8.50
Duplicate invoices for previous billing	$	3.25
Easement letter	$	8.50
Account history	$	8.50
Returned cheque charge (plus bank charges)	$	16.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	12.50
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	25.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	18.00
Disconnect/Reconnect at meter - during regular Hours	$	50.00
Disconnect/Reconnect at meter – after regular hours	$	120.00
Disconnect/Reconnect at pole – during regular hours	$	160.00
Disconnect/Reconnect at pole – after regular hours	$	315.00
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.70)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0776
EB-2007-0578

Retail Service Charges (if applicable)

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0365
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0261
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Tay Service Area
Per EB-2007-0578 Decision

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.18
Distribution Volumetric Rate	$/kWh	0.0116
Regulatory Asset Recovery	$/kWh	0.0058
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	17.31
Distribution Volumetric Rate	$/kWh	0.0177
Regulatory Asset Recovery	$/kWh	0.0039
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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General Service 50 to 4,999 kW

Service Charge	$	210.93
Distribution Volumetric Rate	$/kW	3.3024
Regulatory Asset Recovery	$/kW	0.9416
Retail Transmission Rate – Network Service Rate	$/kW	1.9747
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6747
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	7.35
Distribution Volumetric Rate	$/kWh	0.0177
Regulatory Asset Recovery	$/kWh	0.0079
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	0.72
Distribution Volumetric Rate	$/kW	3.2915
Regulatory Asset Recovery	$/kW	7.4173
Retail Transmission Rate – Network Service Rate	$/kW	1.4968
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3217
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.69
Distribution Volumetric Rate	$/kW	3.7705
Regulatory Asset Recovery	$/kW	1.0734
Retail Transmission Rate – Network Service Rate	$/kW	1.4893
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2946
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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EB-2007-0776
EB-2007-0578

Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular Hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
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
Service Charge for Access to the Power Poles $/pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0866
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0757
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

DRAFT ISSUES LIST

Newmarket-Tay Power Distribution would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2010 Test Year may constitute issues in this Application:

1. ADMINISTRATION (Exhibit 1)

a) Has the Applicant responded appropriately to all interrogatories and technical questions?

b) Is any key information missing, and if so how will it be provided or determined to be unnecessary?

c) Is there agreement on each document that The Applicant has requested to be confidential, and if not how is the matter to be resolved?

2. RATE BASE (Exhibit 2)

a) Are the Applicant's planning assumptions (asset condition, economic conditions, etc.) appropriate?

b) Are the amounts proposed for Capital Expenditures appropriate?

c) Are the in-service dates accurate for recent projects, and appropriate for proposed projects?

d) Has the Working Capital Allowance been determined appropriately?

e) Is the calculation of the proposed Rate Base appropriate?

3. LOADS, CUSTOMERS - THROUGHPUT REVENUE (Exhibit 3)

a) Is the load forecast (including methodology and weather normalization) appropriate?

b) Are the forecasts of factors (number of customers, economic activity) appropriate?

c) Is the impact of CDM initiatives suitably reflected in the econometric-model load forecast?

d) Is the proposed amount for Revenue Offsets appropriate?

e) Is the calculation of the proposed Service and Base Revenue Requirements appropriate?

4. OPERATING COSTS (Exhibit 4)

a) Are the costs incurred under the ongoing arrangement with the Applicant's affiliates appropriate?

b) Are the Staffing Resources and related costs appropriate?

c) Is the Applicant's capitalization and depreciation policy appropriate? Is the depreciation amount appropriate?

d) Is the Applicant's proposal for the transition from GST/PST to HST appropriate?

e) Is the Payment in Lieu of Taxes (including methodology) appropriate?

f) Are taxes and credits (other than PILs) appropriate?

g) Are the overall levels of OM&A budgets appropriate?

5. COST OF CAPITAL AND RATE OF RETURN (Exhibit 5)

a) Is the proposed Capital Structure appropriate?

b) Is the Cost of Debt appropriate?

c) Confirm that 9.85% is the appropriate Rate of Return on Equity?

6. CALCULATION OF REVENUE DEFICIENCY OR SURPLUS (Exhibit 6)

a) Is the Service Revenue Requirement appropriate?

b) Is the calculation of Revenue Deficiency accurate?

7. COST ALLOCATION (Exhibit 7)

a) Is the Applicant’s cost allocation appropriate?

b) Are the proposed revenue-to-cost ratios appropriate?

8. RATE DESIGN (Exhibit 8)

a) Are the customer charges and the fixed-variable splits for each class appropriate?

b) Are the proposed Retail Transmission Service Rates appropriate?

c) Is the Smart Meter funding adder appropriate?

d) Is the proposal for no impact mitigation appropriate?

e) Is the Applicant’s proposed Tariff of Rates and Charges appropriate?

9. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

a) Is the proposal for the amounts, disposition, and continuance appropriate?

b) Are the proposed Deferral and Variance Account rate riders appropriate?

c) Is the proposed recovery of the Global Adjustment (sub-account of 1588) from RPP and non-RPP customers appropriate?

10. LRAM/SSM (Exhibit 10)

a) Is the quantity of load reduction attributable to CDM initiatives appropriate?

b) Is the proposed rate rider appropriate?

UTILITY WITNESSES

Should the Board require an oral hearing, the names of the Applicant's witnesses will be provided.

Witness CVs

Curriculum Vitae for any witnesses will be provided upon request.

Exhibit 1: Administrative Documents

Tab 2 (of 4): Company Overview

SYSTEM DESCRIPTION

The Applicant is licensed by the Board to distribute electricity to the inhabitants of the Town of Newmarket and the Township of Tay (license ED-2007-0624). The Applicant's license is in good standing.

The Applicant serves 29138 residential customers, 2893 commercial customers and 398 industrial customers as well as several unmetered loads, approximately 8494 street lights and 421 sentinel lights using 585 km of conductor and through 468 km of conduit in a service area that is 29.95 hectares square. In 2009, residential customers consumed 39% of all power delivered by The Applicant. The Applicant provides its customers with an appropriate quality of service and is an early adoptee of Smart Metering technology and actively participates in CDM through the provision of programs it provides and the provision of programs under contract to the OPA.

The Applicant is owned by the Town of Newmarket and the Township of Tay. The Applicant is affiliated with 8 non-active other legal entities.

The Applicant's Newmarket service area is experiencing significant and enduring growth. As a result, The Applicant will commence to receive deliveries of bulk power through 4 of the 8 feeders emanating from the Holland Junction TS in 2010 and will continue to take bulk power deliveries from 4 feeders emanating from the Armitage TS. In 2010 The Applicant will cease to take service from 2 feeders emanating from the Armitage TS that it has relied on since the early 1990's. The Tay service area will continue to take delivery of energy and power from Hydro One Networks distribution system as a Low Voltage customer.

The Applicant is in compliance with all regulatory instruments.

Neighbouring Utilities

The Applicant's Newmarket service area is bordered by:

Hydro One Networks, Inc.
Address: 483 Bay St.
Toronto, ON M5G 2P5
Phone: 416-345-5000

PowerStream, Inc.
Address: 161 Cityview Blvd.
Vaughan, ON L4H 0A9
Phone: 905-417-6900

Distribution System

Diagrams of The Applicant's Newmarket and Tay service areas are provided in the attachment E1/T2/S1/A1.

The Applicant's Newmarket service area is bordered by the following utilities:

- Hydro One
- PowerStream Inc.

Hydro One transmission assets traverse The Applicant's Newmarket service area.

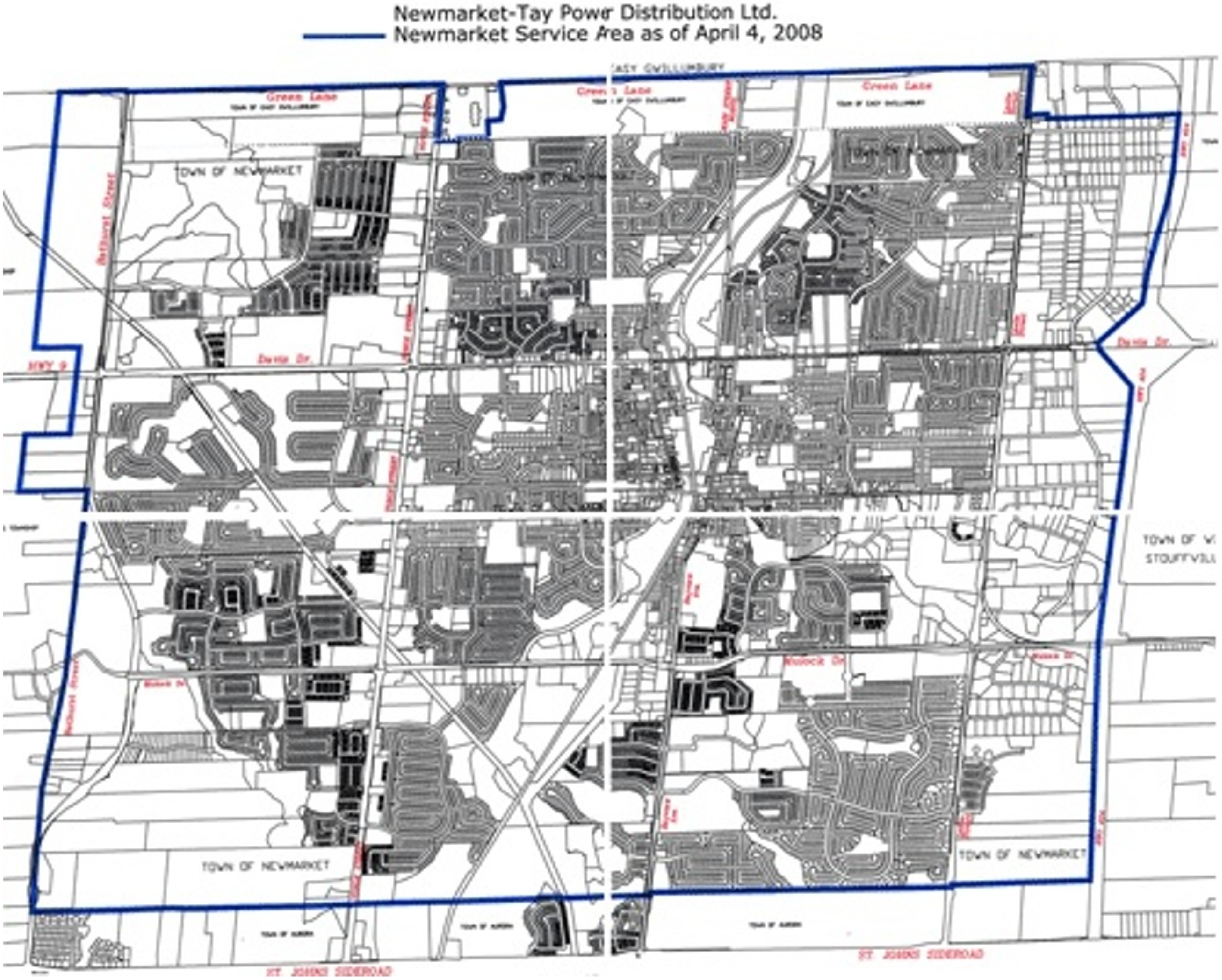
The Applicant's Tay service area is bordered by the following utilities:

- Midland Power Utility Corporation
- Hydro One Inc.

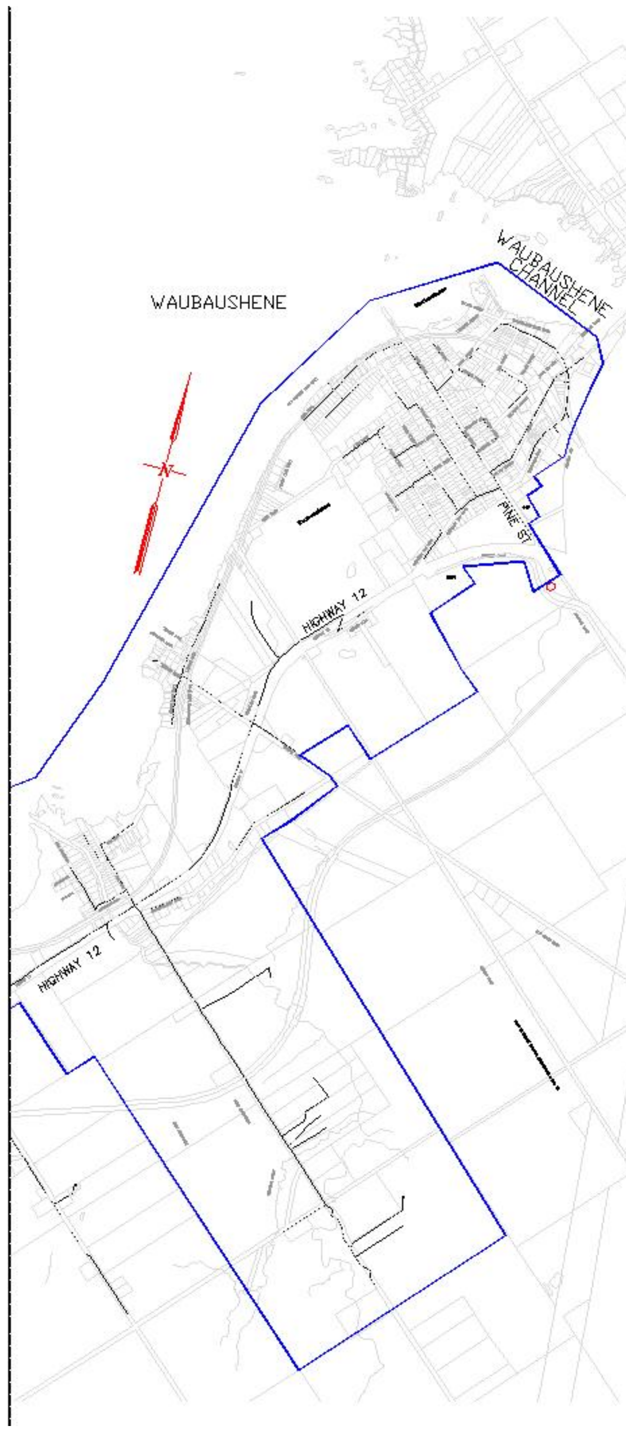
The Applicant's Newmarket distribution system is served by Hydro One transmission; it is not an embedded or a host LDC. The Applicant's Tay distribution system is served by Hydro One distribution; it is not an embedded or a host LDC.

Attachment 1 (of 1):

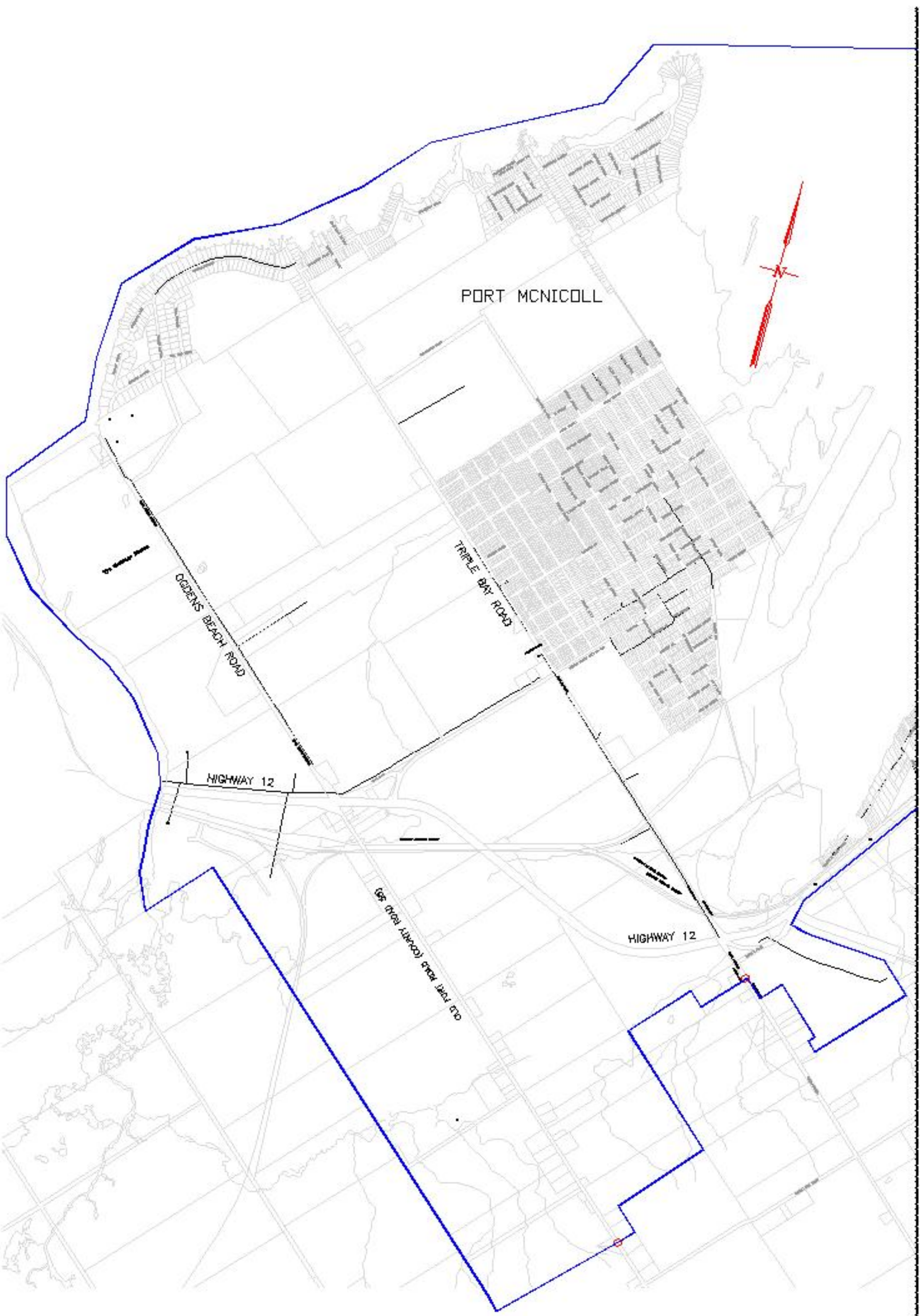
Map of LDC's Distribution System


Newmarket-Tay Power Distribution Ltd.
Newmarket Service Area as of April 4, 2008
EAST GWILLIMBURY
Green Lane
TOWN OF NEWMARKET
Davis Dr.
HWY 9
Mulock Dr
TOWN OF NEWMARKET
TOWN OF NEWMARKET
ST. JOHNS SIDEROAD
ST. JOHNS SIDEROAD

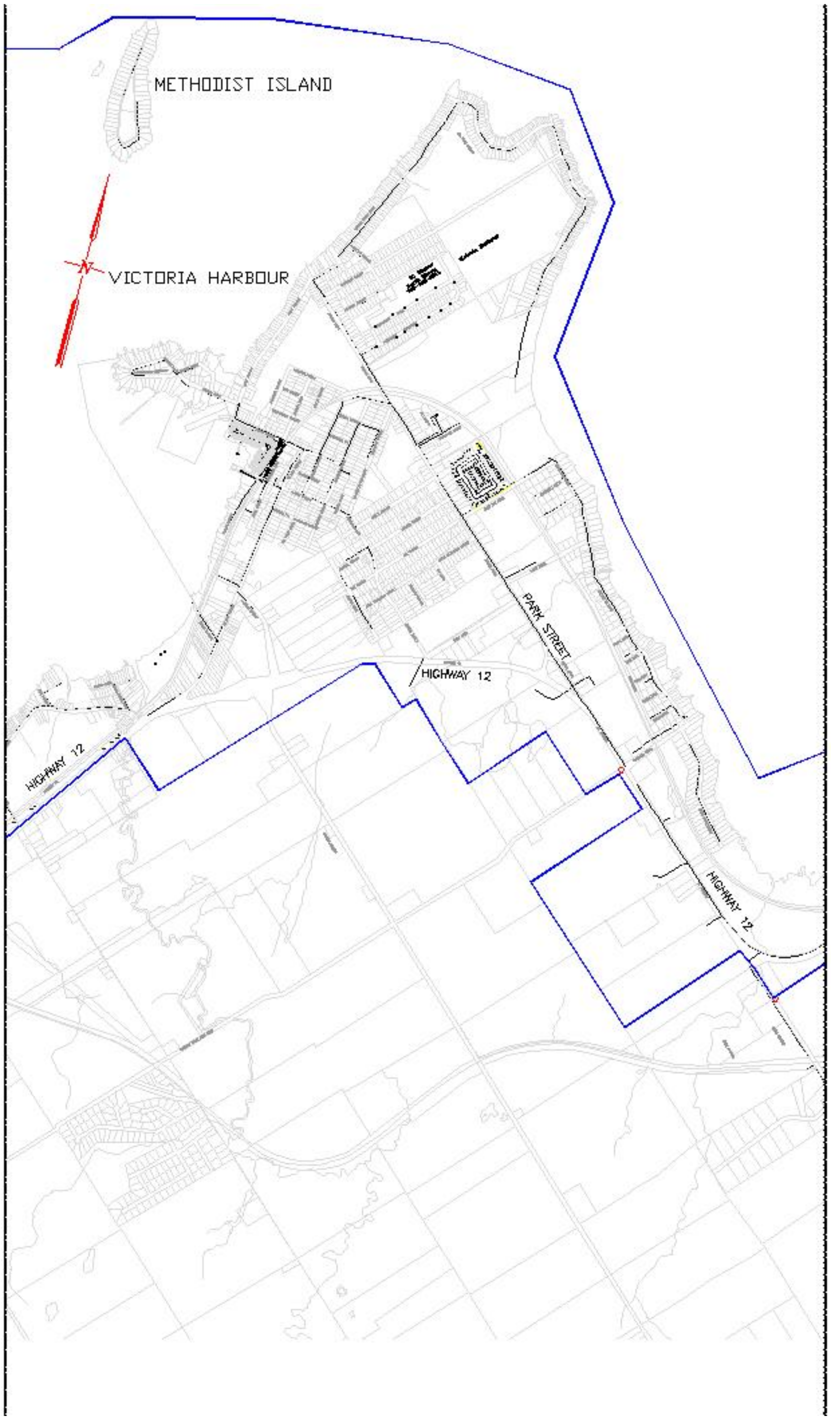
Service Area for Waubaushene



Service Area for Port McNicol



Service Area for Victoria Harbour



AMALGAMATION BACKGROUND

On March 8, 2007, the Ontario Energy Board (OEB) granted Newmarket Hydro Ltd.(NHL) and Tay Hydro Electric Distribution Company Inc. (THEDCI) leave to amalgamate. The merger of NHL and THEDCI was completed on May 1, 2007 and the amalgamated entity formed was Newmarket-Tay Power Distribution Ltd.

On May 1, 2007, NT Power applied to the OEB for cancellation of the licences of NHL (ED-2002-0553) and THEDCI (ED-2002-0519), as well as for issuance of a new electricity distribution licence for NT Power.

The following information on the merger is presented in the following pages.

- NT Power Merger Background
- Merger media release
- Decision and Order re. Amalgamation of both service territories
- Electricity Distribution Licence

BACKGROUND

Amalgamation of Newmarket Hydro and Tay Hydro

New utility ensures service levels to consumers while enhancing shareholder value

Newmarket, Ontario: In 2004, the Boards of Directors of both Newmarket Hydro Limited and Tay Hydro Electric Distribution Company Inc. agreed that the potential synergies and financial benefits of amalgamating the two utilities should be explored. Executive staff at the two utilities conducted detailed reviews of their operations and reported their findings in June 2005. An exhaustive analysis, supported by technical, financial and legal advisors, concluded that a merged utility would deliver a modest short-term improvement in shareholder value while ensuring the stability of future dividend payments and the security of service excellence to residential and business consumers. Accordingly, it was recommended that the merger should be undertaken because it was in the best interests of both utilities' shareholders and customers.

The challenges of the Ontario electricity marketplace

The current and immediately foreseeable environment in which local distribution companies such as Newmarket Hydro and Tay Hydro operate is characterized by regulatory and legislative uncertainty, extraordinary cost pressures on utilities and consumers, growing supply shortfalls and increasing consumer demand. Further complicated by a recent history of continually changing government policy, the operating environment is not one that is particularly conducive to traditional business planning.

By merging, Newmarket Hydro and Tay Hydro believe they will be better able to respond to the many challenges of this environment even as they strive to improve service levels to consumers and maintain shareholder value.

Newmarket Hydro Limited and Tay Hydro Electric Distribution Company Inc.

Fully owned by the Town of Newmarket, Newmarket Hydro serves more than 25,000 residential and business customers in the Newmarket area as the local electricity distribution company. It is the thirtieth largest utility in Ontario and has 44 full-time and two contract employees. Paul Ferguson is the president of Newmarket Hydro. For more information about Newmarket Hydro, see www.nmhydro.ca. Newmarket Hydro is an industry leader and innovator in electricity distribution systems and is widely regarded as a utility with successful experience in managing rapid growth.

Based in Port McNicoll on the shores of Georgian Bay in Simcoe County, Tay Hydro distributes electricity to the Tay Township communities that include, in addition to Port McNicoll, Waubaushene, Victoria Harbour, Methodist Island and surrounding rural areas. Serving approximately 4,000 customers, Tay Hydro has eight full-time employees and is the sixty-ninth largest utility in the province. Like Newmarket Hydro, Tay Hydro is fully owned by its municipality. The president of Tay Hydro is Jim Crawford. For more information about Tay Hydro, see www.tayhydro.com. Long prized for its cottaging and boating opportunities, the region is now poised for significant growth both of its local population base and the range and number of its businesses.

Geography an asset

The service areas of the two utilities are about an hour's drive from each other along Highway 400, a geographical separation that presents no significant obstacles to a merged operation. In fact, it may even represent a benefit when adverse weather conditions cause power disruptions in one region and not the other, allowing additional emergency resources to be dispatched to areas in need.

The commonality of the electricity distribution systems and hardware between the two utilities makes them highly compatible from a technical perspective. Both utilities are already familiar with each other's operations as they share a long history of working together through the Upper Canada Energy Alliance.

Merger to close when transfer tax changes favourable

Currently, a transfer tax of 33 per cent of the value of assets used to generate, transmit, distribute or retail electricity is imposed by the Ontario government when such assets are sold or transferred to another entity such as the proposed merged utility Newmarket Tay Power Distribution Ltd.

Consequently, the formal merger of the utilities of Newmarket and Tay will not close until such time as the tax is either cancelled for such transactions or a previous exemption is reinstated. The utilities and their municipalities are ready for a quick response should an opportunity present itself.

In the interim, joint service agreements between the two utilities are in place so that we can begin to realize some of the benefits of an amalgamated operation.

For further information in Newmarket:

Iain Clinton 905 953-8548

Rick Butts 905 853-7395 (cell: 905 717-2878)

For further information in Tay:

Jim Crawford 705 534-7281

Ted Walker 705 534-7248

FOR IMMEDIATE RELEASE

Newmarket and Tay electricity utilities to merge

Amalgamated company positioned to face challenges of Ontario electricity market

Newmarket, Ontario (May 10, 2006):

Newmarket Hydro and Tay Hydro are joining forces to create a new electricity distribution company, Newmarket Tay Power Distribution Ltd. The amalgamated utility will be better equipped to work in the best interests of Newmarket and Tay residents and businesses in the changing Ontario electricity marketplace.

The amalgamation is subject to the approval of the Ontario Energy Board and will be completed only when the Ontario government enacts changes to the current provincial 33 per cent tax on electricity asset transfers. A detailed and extensive analysis of the potential benefits to both communities was undertaken by senior staff at the utilities supported by technical, financial and legal advisors.

Putting these two utilities together delivers cost savings. By eliminating certain duplicate costs and enhancing administrative efficiencies, an annual incremental savings estimated at approximately $70,000 will be achieved.

A combined utility's inventory also presents savings opportunities because large capital equipment can be shared between the communities as needed while economies of scale produce lower unit costs on purchased materials and services. No job losses are anticipated as a result of merging the two utilities with the majority of the cost reductions coming from rationalizing consulting and contracting expenses.

For customers, nothing changes as the merged utility will seamlessly assume responsibility for electricity distribution in the combined service areas. "Tay customers and Newmarket customers continue to contact the local business office they do now for service on their accounts," says Paul Ferguson, president of Newmarket Hydro.

But what does change is the "back office" as the teaming up of Tay Hydro and Newmarket Hydro immediately creates a utility with the larger geographical presence and scale necessary to leverage synergies to the advantage of its customers. Scale and the potential for future growth are critical factors in efficiently deploying the technologies and programs called for by new market realities such as smart meter projects and conservation and demand management initiatives. These same factors also give the utility greater presence before policy makers and regulators when commenting on issues important to customers in both communities.

Located on the shores of Georgian Bay and poised for major development, Tay Township includes the communities of Victoria Harbour, Port McNicoll and Waubaushene as well as the surrounding rural areas.

"The expertise Newmarket Hydro has in managing growth in electricity distribution will be invaluable to this community," says Jim Crawford, president of Tay Hydro. "We also recognize the future growth opportunities this merger creates collectively for all of us. Amalgamation is the first step in bringing those benefits to consumers in Tay and Newmarket."

"The business case for this merger is that it is the right thing to do for the customers in Newmarket and Tay," adds Paul Ferguson. "With these utilities teaming up, we're more competitive, and we have greater flexibility in managing future rate increases and limiting the impact on consumers, all of which helps in protecting shareholder value over the long run." Additionally, the merger is helpful in the context of industry and regulator discussions concerning the most efficient size of distributors as a means to lowering costs and improving service to customers.

Separated by approximately 110 kilometres or about an hour's drive along Highway 400, the two communities can take advantage of geography to deploy critical resources during weather-related emergencies to where they are needed the most. It is not unusual for Newmarket and Tay to have different local weather conditions, presenting an obvious advantage when one area experiences power interruptions due to severe weather. An invaluable emergency resource, such as an experienced line crew, may be available just an hour away and make all the difference in getting a neighbourhood's lights back on after a storm.

The local hydro utilities of Newmarket and Tay have much in common. Both have strong ties to their communities and are wholly owned by their respective municipalities. From a technical perspective, the two utilities are very compatible, working with the same voltage levels and using similar electricity distribution systems and hardware. More important to the success of the amalgamation is that the partners know and trust each other, having had a five-year history of working together through the Upper Canada Energy Alliance, a cooperative of municipal electric utilities.

For further information in Newmarket:

Iain Clinton 905 953-8548

Rick Butts 905 853-7395 (cell: 905 717-2878)

For further information in Tay:

Jim Crawford 705 534-7281

Ted Walker 705 534-7248

EB-2007-0624

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an application pursuant to sections 60 and 77(5) of the *Ontario Energy Board Act, 1998* by Newmarket-Tay Power Distribution Ltd. for the issuance of a distribution licence for Newmarket-Tay Power Distribution Ltd. and for the cancellation of the distribution licences for Newmarket Hydro Ltd. (ED-2002-0553) and Tay Hydro Electric Distribution Company Inc. (ED-2002-0519).

By delegation, before: Jennifer Lea

DECISION AND ORDER

On December 19, 2006, Newmarket Hydro Ltd. ("Newmarket") and Tay Hydro Electric Distribution Company Inc. ("Tay") as co-applicants, filed an application (EB-2006-0344) with the Ontario Energy Board seeking leave for the amalgamation of Newmarket and Tay. By separate letter on that date, Newmarket and Tay applied for the cancellation of their separate licences effective at the time of completion of the amalgamation forming the entity Newmarket-Tay Power Distribution Inc. ("Newmarket-Tay").

On March 8, 2007 the Board granted Newmarket and Tay leave to amalgamate.

By letter dated May 1, 2007, the newly amalgamated entity, Newmarket-Tay, filed with the Board a notice of completion of the amalgamation. Newmarket-Tay also sought a new electricity distributor licence for the service areas served by the former Newmarket and Tay; the cancellation of Newmarket's current distribution licence ED-2002-0553 and the cancellation of Tay's electricity distribution licence ED-2002-0519. On June 8, 2007, Newmarket-Tay filed the appropriate application forms required for a new licence.

I have disposed of this application without a hearing as no person will be adversely affected in a material way by the outcome of the proceeding and the applicant has consented to the disposing of the proceeding without a hearing.

After considering the distribution licence application, and in light of the fact that the Board has granted leave for the amalgamation transaction and that the amalgamation is complete, I find that it is in the public interest to issue a new electricity distribution licence to Newmarket-Tay, and to cancel Newmarket's current distribution licence ED-2002-0553 and Tay's electricity distribution licence ED-2002-0519.

IT IS ORDERED THAT:

1. The application for an electricity distribution licence is granted, on such conditions as are contained in the attached licence; and

2. The electricity distribution licences of Newmarket Hydro Ltd. (ED-2002-0553) and Tay Hydro Electric Distribution Company Inc. (ED-2002-0519) be cancelled as of August 24, 2007.

DATED at Toronto, August 24, 2007

ONTARIO ENERGY BOARD

Original signed by

Jennifer Lea
Special Advisor, Market Operations

Electricity Distribution Licence

ED-2007-0624

Newmarket-Tay Power Distribution Ltd.

Valid Until

August 23, 2027

Original signed by

Jennifer Lea
Special Advisor, Market Operations
Ontario Energy Board
Date of Issuance: August 24, 2007

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th. Floor
Toronto, ON M4P 1E4

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

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1 Definitions

In this Licence:

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

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

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

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

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

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

"**Licensee**" means Newmarket-Tay Power Distribution Ltd.

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

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

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

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

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

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

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

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

2 Interpretation

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

3 Authorization

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

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

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

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

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

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

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

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

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

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

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

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

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

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

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

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

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

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

8 Obligation to Sell Electricity

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

9 Obligation to Maintain System Integrity

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

10 Market Power Mitigation Rebates

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

11 Distribution Rates

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

12 Separation of Business Activities

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

13 Expansion of Distribution System

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

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

14 Provision of Information to the Board

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

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

14.3 The Licensee shall:

a) immediately notify the Board in writing of the notice; and

b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this licence.

15 Restrictions on Provision of Information

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

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

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

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

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

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

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

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

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

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

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

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

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

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

17 Term of Licence

17.1 This Licence shall take effect on August 24, 2007 and expire on August 23, 2027. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

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

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

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

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

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

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

20 Copies of the Licence

20.1 The Licensee shall:

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

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

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

1. The Town of Newmarket as of January 1, 1979.

2. Part of the Town of East Gwillimbury, extending from Bathurst Street in the west, to Leslie Street in the east, from the northern boundary of the Town of Newmarket in the south, to the south side of Green Lane Drive in the north, with the following exception:

   - the area of land, being composed of Part of Lot 100, Concession 1, East of Yonge Street, more particularly described as Parts 1-13 on Reference Plan 65R-22350, also known as the Silver City Plaza; and

   - the area of land at the southwest corner of Leslie Street and Green Lane where consumers are serviced by Hydro One Networks under load transfer arrangements at the date of issuance of this Licence.

3. The former urban areas of Port McNicoll including Paradise Point, Victoria Harbour and Waubaushene as of December 31, 1993.

4. Within the Township of Tay, an area commences to shoulder with Midland Power at the Wye River. The adjacent geographic area south of Highway 12 and all geographic area north of Highway 12 from the Wye River easterly to County Road 58 (Old Fort Road). Thence south on County Road 58 incorporating services east and west of County Road 58, to the existing open point just north of Elliot’s Corner. Highway 12 will form a natural electrical boundary just east of County Road 58 for the expanded area and for all geographic area north of Highway 12 to existing easterly boundary in Waubaushene. Easterly from County Road 58 encompassing all adjacent distribution system south of Highway 12 which incorporates natural open points and easterly to the end of Trestle Road. Thence northerly crossing over Highway 12 to the west end of Mitchell’s Beach and continuing easterly north of Highway 12 to the existing electrical boundary at the west end of the former Village of Victoria Harbour. The expanded area shall then continue from the easterly existing Victoria Harbour boundary located just south of Highway 12 along southerly side of Highway 12 to Rosemount Road. South on Rosemount Road to the end of the existing line incorporating services east and west of Rosemount Road. The boundary will continue just south of Highway 12 to the most easterly existing boundary of Waubaushene.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

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

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

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

3. Pass Through of Rebate

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

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

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

“ONTARIO POWER GENERATION INC. rebate”

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

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

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

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

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

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

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

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

2. Information Given to IESO

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

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

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

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

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

3. Pass Through of Rebate

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

a retailers who serve one or more consumers in the distributor’s service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

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

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

"ONTARIO POWER GENERATION INC. rebate"

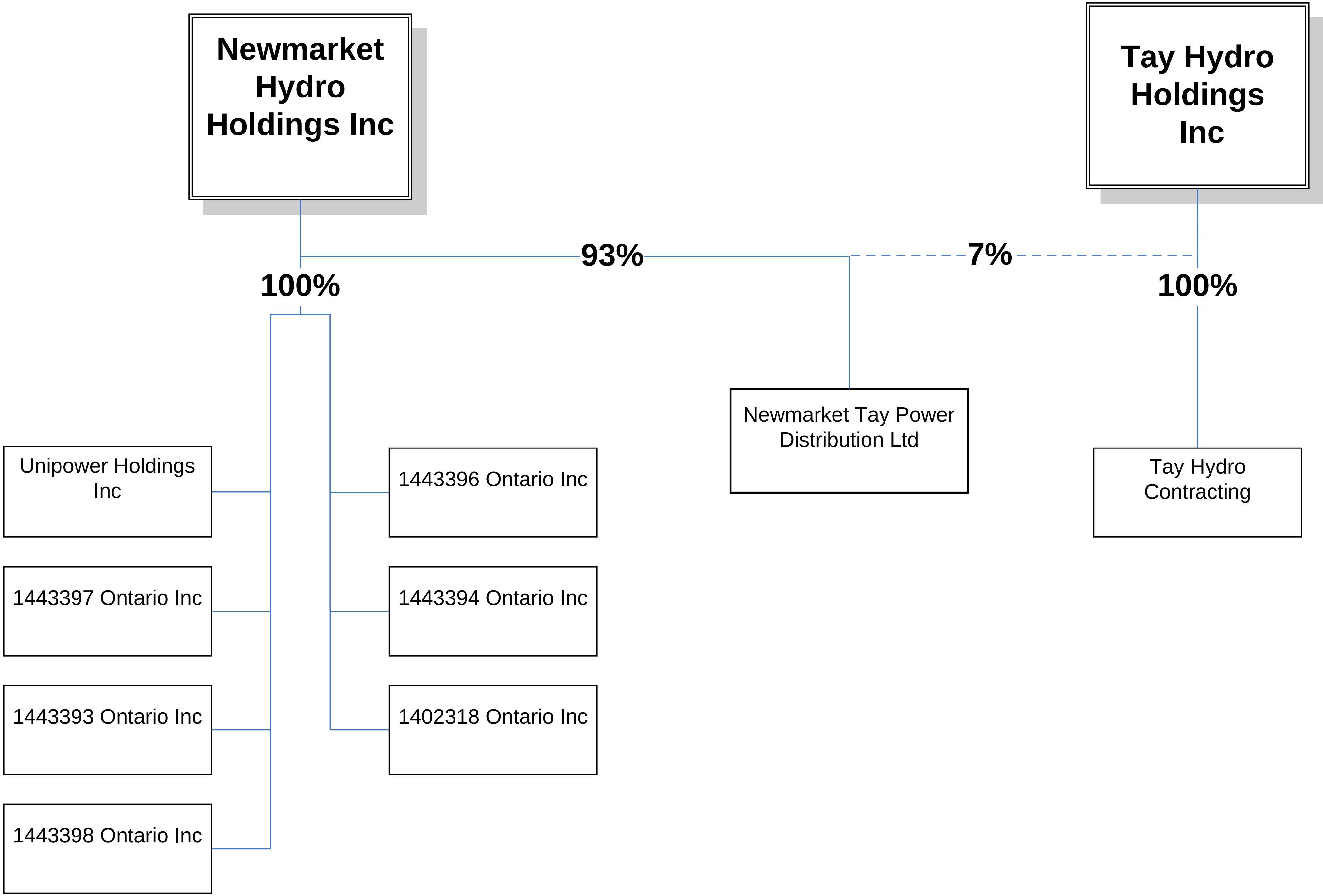
Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such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

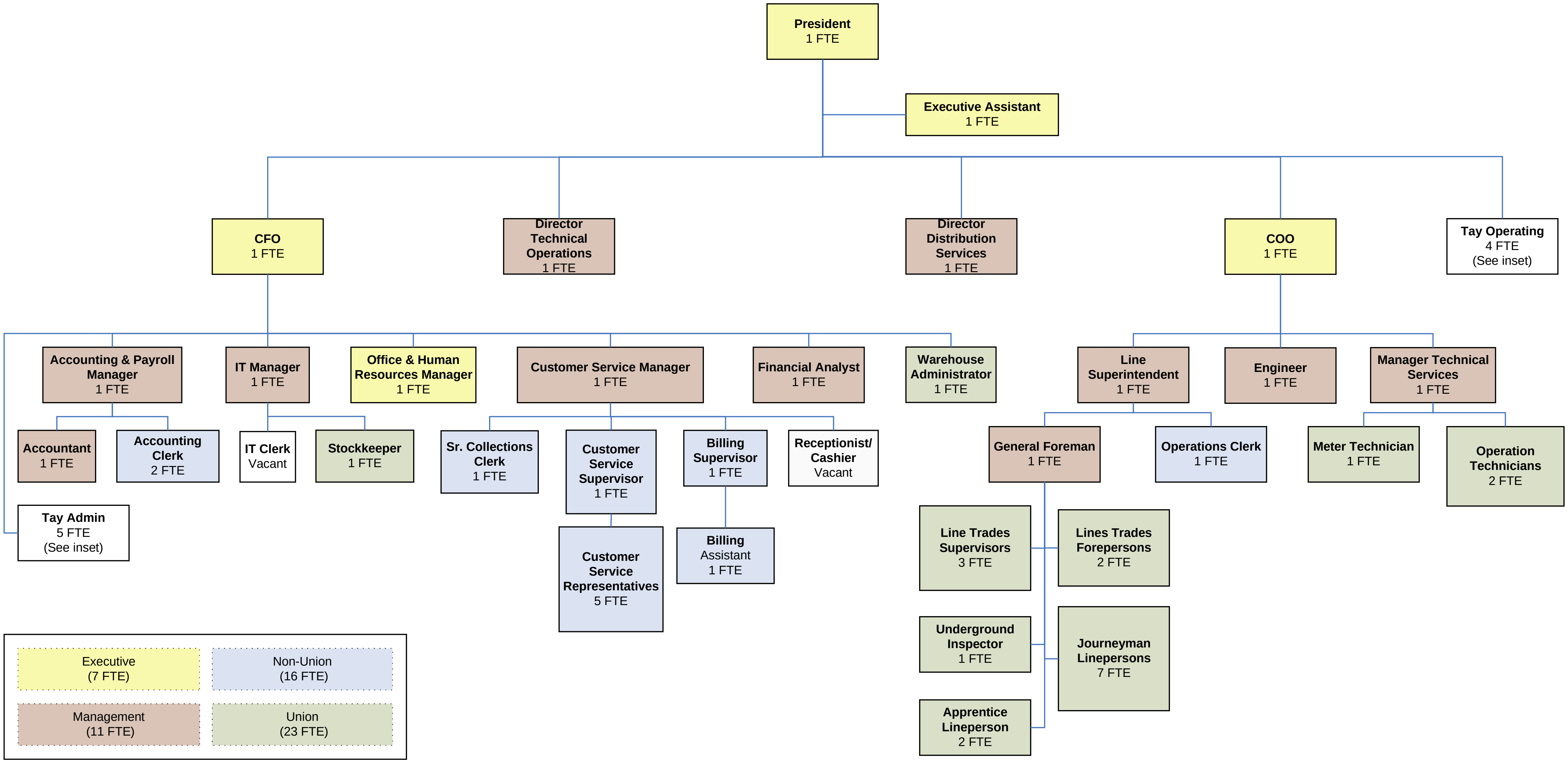
Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

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

CORPORATE ORGANIZATION

The following attachments depicts The Applicant's Corporate Entities Relationships and its Organizational Chart.


Newmarket Hydro Holdings Inc
Tay Hydro Holdings Inc
93%
7%
100%
100%
Unipower Holdings Inc
1443397 Ontario Inc
1443393 Ontario Inc
1443398 Ontario Inc
1443396 Ontario Inc
1443394 Ontario Inc
1402318 Ontario Inc
Newmarket Tay Power Distribution Ltd
Tay Hydro Contracting



President
1 FTE
Executive Assistant
1 FTE
CFO
1 FTE
Director Technical Operations
1 FTE
Director Distribution Services
1 FTE
COO
1 FTE
Tay Operating
4 FTE
(See inset)
Accounting & Payroll Manager
1 FTE
IT Manager
1 FTE
Office & Human Resources Manager
1 FTE
Customer Service Manager
1 FTE
Financial Analyst
1 FTE
Warehouse Administrator
1 FTE
Line Superintendent
1 FTE
Engineer
1 FTE
Manager Technical Services
1 FTE
Accountant
1 FTE
Accounting Clerk
2 FTE
IT Clerk
Vacant
Stockkeeper
1 FTE
Sr. Collections Clerk
1 FTE
Customer Service Supervisor
1 FTE
Billing Supervisor
1 FTE
Receptionist/ Cashier
Vacant
General Foreman
1 FTE
Operations Clerk
1 FTE
Meter Technician
1 FTE
Operation Technicians
2 FTE
Tay Admin
5 FTE
(See inset)
Customer Service Representatives
5 FTE
Billing Assistant
1 FTE
Line Trades Supervisors
3 FTE
Lines Trades Forepersons
2 FTE
Underground Inspector
1 FTE
Journeyman Linepersons
7 FTE
Apprentice Lineperson
2 FTE
Executive
(7 FTE)
Non-Union
(16 FTE)
Management
(11 FTE)
Union
(23 FTE)

Tay Division

AFFILIATE TRANSACTIONS

The Applicant affiliate transactions are presented in Exhibit 4.

Exhibit 1: Administrative Documents

Tab 3 (of 4): Board Directions

BOARD DIRECTIONS FROM PREVIOUS EDR DECISIONS

There are no Board directions from previous EDR decisions applicable.

ACCOUNTING ORDERS

The Board has not issued any unique accounting orders to The Applicant. The Applicant applies the generically authorized accounting orders and concepts authorized from time to time by the Board (eg., Smart Meter deferral accounting, CDM costs incurred through 3rd Tranche authorization, costs incurred as a result of contracting with the OPA for the provision of CDM).

The Applicant requests to set-up a deferral account to use for costs associated with the Green Energy Act.

The Applicant requests to set-up a deferral account to use for cost associated with Low-Income Energy Assistance Program (LEAP).

The Applicant requests to set-up a deferral account to use to record costs associated with the late payment charges class action.

COMPLIANCE ORDERS

No compliance orders have been issued by the Board to The Applicant.

OTHER BOARD DIRECTIONS

There have been no other Board directions issued to The Applicant.

Exhibit 1: Administrative Documents

Tab 4 (of 4): Finance

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements were prepared in accordance with Canadian generally accepted accounting principles. The significant policies are detailed as follows:

a) Electricity Regulation

The company is subject to rate regulation by the OEB. The OEB is charged with the responsibility of approving rates for the transmission and distribution of electricity. The following regulatory policies are practiced in a rate regulated environment.

i. Regulatory Assets

Regulatory assets consist of deferred qualifying transition costs and various rate and retail variance accounts. The costs related to these accounts are deferred for accounting purposes because it is probable that they will be recovered in future rates. Regulatory assets recognized at December 31, 2006 are disclosed in Note 5 of The Applicant's Audited Financial Statements for 2007 (Ex 1, Tab 4, Schedule 2, Attachment 2). The Applicant continually assesses the likelihood of the recovery of these assets. If recovery is no longer considered probable, the amounts are charged to operations in the year the assessment is made. The recovery of regulatory assets commenced in April 1, 2004.

ii. Corporate Taxes

Under the Electricity Act, 1998, the Company is required to make payments in lieu of income taxes (PILS) to the Ontario Electricity Financial Corporation (OEFC). As directed by the OEB, The Applicant provides for PILS payments using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts. Additional details related to the calculation and method of accounting for PILS is included in

Note 4 of The Applicant's Audited Financial Statements for 2007 (Ex 1, Tab 4, Schedule 2, Attachment 2).

b) Management Estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

c) Short-term Investments

Short-term investments are carried out at the lower of cost and market value.

d) Inventory

Inventory is valued at the lower end of cost and net realizable value with costs being determined on a weighted average basis. Inventory consists primarily of parts and materials used for maintenance and capital projects.

e) Property, Plant and Equipment

Property, plant and equipment are recorded at cost. The Applicant provides for amortization using the straight-line method at rates designed to amortize the cost of the property, plant and equipment over their estimated useful lives. The annual amortization rates are as follows:

Transmission and distribution systems	25 to 30 years
Office equipment	3 to 10 years
Leasehold improvements	10 years
Plant and equipment	10 to 15 years

Contributors for capital construction consist of third party contributions toward the cost of constructing distribution assets. The third party contribution is calculated through an economic evaluation as per the OEB Distribution Service Code. Contributed capital amounts are recorded as received and amortized over the same period as the asset to which they relate being 25 to 30 years.

f) Financial Instruments

The estimated fair value of the The Applicant's financial assets and liabilities approximates carrying value. Unless otherwise noted it is management's opinion that The Applicant is not exposed to significant interest, currency or credit risk.

The Applicant is exposed to credit risk from customers. However, The Applicant has a significant number of customers which minimizes concentration of credit risk.

g) Deferred Revenue

Deferred revenue represents amounts received from the OEB related to Conservation Demand Management funds received and not expended in the current year.

h) Related Party Transactions

Related party transactions are in the normal course of operations and have been measured at the exchange amount which is the amount of consideration established and agreed to by the related parties. Details of related party transactions and balances are detailed in Note 8 of The Applicant's Audited Financial Statements for 2007 (Ex 1, Tab 4, Schedule 2, Attachment 2).

i) Employee Future Benefits

The Applicant pays certain health, dental and life insurance benefits on behalf of its retired employees. The Applicant recognizes these post-retirement costs in the period in which the employees earn the benefits. The cost of the employee future benefits earned by employees is actuarially determined using the projected benefit method prorated on length of service and management's best estimate of salary escalation, retirement ages of employees, employee turnover and expected health and dental care costs. The recent actuarial valuation of the obligation was performed for December 31, 2004. Details related to the post-employment benefits are detailed in Note 10 of The Applicant's Audited Financial Statements for 2007 (Ex 1, Tab 4, Schedule 2, Attachment 2).

j) Revenue Recognition

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 period. The related cost of power is recorded on the basis of the power billed by the Independent Electricity System Operator (IESO).

k) Reclassification

Certain reclassifications have been made to the 2005 financial statements to conform with the classifications used in 2006.

HISTORICAL FINANCIAL STATEMENTS

The Financial Statements presented in the following schedule depict The Applicant's formal records of its financial activities. These Financial Statements are for 2008 and 2009. These statements are prepared and audited by Collins Barrow LLP. Please note that The Applicant does not prepare interim financial statements for the current year.

FINANCIAL STATEMENTS OF

NEWMARKET-TAY POWER DISTRIBUTION LTD.

December 31, 2008

TABLE OF CONTENTS

Collins Barrow
Chartered Accountants

Collins Barrow
Chartered Accountants

Collins Barrow Kawarthas LLP
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Peterborough, Ontario
K9H 3J9

T. 705.742.3418
F. 705.742.9775
email: peterborough@collinsbarrow.com

AUDITORS' REPORT

To the Shareholders of
Newmarket-Tay Power Distribution Ltd.

We have audited the balance sheet of Newmarket-Tay Power Distribution Ltd. as at December 31, 2008 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Collins Barrow Kawarthas LLP

Chartered Accountants
Licensed Public Accountants

Peterborough, Ontario
March 25, 2009

NEWMARKET-TAY POWER DISTRIBUTION LTD.
BALANCE SHEET

As at December 31, 2008

	2008 $	2007 $
ASSETS		
Current assets		
Cash	6,820,527	6,633,900
Short-term investments (note 3)	1,850,016	837,106
Accounts receivable	6,767,742	7,214,300
Unbilled revenue	8,901,729	8,069,714
Income taxes receivable (note 4)	780,000	464,109
Inventory	1,157,139	995,482
Prepaid and other	299,486	379,805
	26,576,639	24,594,416
Other assets		
Property, plant and equipment (note 5)	48,887,373	45,946,452
	75,464,012	70,540,868
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities (note 6)	11,271,988	9,422,905
Dividend payable (note 7)	1,665,000	1,665,000
Current portion of deposits held	377,586	352,586
Current portion of long-term debt (note 8)	200,000	200,000
	13,514,574	11,640,491
Long-term liabilities		
Dividend payable (note 7)	-	1,665,000
Deposits held	3,849,504	4,325,967
Long-term debt (note 8)	23,742,821	23,978,821
Employee future benefits (note 9)	839,857	742,354
Deferral accounts (note 10)	2,846,656	141,246
	31,278,838	30,853,388
Shareholders' equity		
Share capital (note 12)	27,140,206	27,140,206
Retained earnings	3,530,394	906,783
	30,670,600	28,046,989
	75,464,012	70,540,868

The accompanying notes are an integral part of these financial statements

NEWMARKET-TAY POWER DISTRIBUTION LTD.
STATEMENT OF INCOME AND RETAINED EARNINGS

For the year ended December 31, 2008
(with comparative figures for the eight month period ended December 31, 2007)

	2008 $	2007 $
Sales	68,759,205	48,901,994
Cost of power	53,679,660	38,699,759
Gross profit	15,079,545	10,202,235
Expenses		
Amortization	3,748,992	2,732,316
Administration	2,446,541	1,599,053
System operation and maintenance	2,177,029	1,180,659
Customer billing and collecting	1,737,748	1,132,815
Interest - long term debt	1,503,931	1,007,463
Property and capital taxes	260,277	190,206
Interest - customer deposits	130,443	83,656
	12,004,961	7,926,168
Income before undernoted items and income taxes	3,074,584	2,276,067
Other income (expense)		
Loss on disposal of meters (net)	-	(1,106,082)
Service and retailer charges	155,403	104,933
Rental and other	192,706	135,084
Occupancy, connection and collection fees	492,715	306,976
Interest	316,199	307,093
	1,157,023	(251,996)
Income before income taxes	4,231,607	2,024,071
Provision for income taxes (note 13)	1,607,996	1,117,288
Net income for the year	2,623,611	906,783
Retained earnings - beginning of year	906,783	-
Retained earnings - end of year	3,530,394	906,783

The accompanying notes are an integral part of these financial statements

NEWMARKET-TAY POWER DISTRIBUTION LTD.
STATEMENT OF CASH FLOWS

For the year ended December 31, 2008
(with comparative figures for the eight month period ended December 31, 2007)

	2008 $	2007 $
CASH PROVIDED FROM (USED FOR)		
Operating activities		
Net income for the year	2,623,611	906,783
Items not affecting cash		
Amortization	4,082,048	2,732,316
Loss on disposal of property, plant and equipment	-	1,106,082
Employee future benefits	97,503	742,354
	6,803,162	5,487,535
Change in non-cash working capital items (note 14)	53,487	(8,537,611)
	6,856,649	(3,050,076)
Investing activities		
Purchase of property, plant and equipment	(7,022,969)	(49,791,850)
Proceeds on disposal of property, plant and equipment	-	7,000
Issuance of share capital	-	27,140,206
Deferral accounts	2,705,410	141,246
Increase (decrease) in dividend payable	(1,665,000)	3,330,000
	(5,982,559)	(19,173,398)
Financing activities		
Issuance of long-term debt	-	24,375,821
Repayment of long-term debt	(236,000)	(197,000)
Deposits held	(451,463)	4,678,553
	(687,463)	28,857,374
Increase in cash	186,627	6,633,900
Cash - beginning of year	6,633,900	-
Cash - end of year	6,820,527	6,633,900

The accompanying notes are an integral part of these financial statements

1. NATURE OF OPERATIONS

Newmarket-Tay Power Distribution Ltd. (the Company) is a subsidiary of Newmarket Hydro Holdings Inc. and was formed as a result of the amalgamation of Newmarket Hydro Ltd. and Tay Hydro Electric Distribution Company Inc. on May 1, 2007. Tay Hydro Inc. has a 7% non-controlling interest in the Company.

The principal activity of the Company is to distribute electricity to the residents and businesses in the Town of Newmarket and the Township of Tay under licence issued by the Ontario Energy Board (OEB). The Company is regulated by the OEB and adjustments to its distribution rates require OEB approval.

2. SIGNIFICANT ACCOUNTING POLICIES

(a) *Electricity regulation*

The Company is subject to rate regulation by the Ontario Energy Board (OEB). The OEB is charged with the responsibility of approving rates for the transmission and distribution of electricity. The following regulatory policies are practiced in a rate regulated environment.

(i) Deferral accounts

Deferral accounts consist of deferred qualifying transition costs and various rate and retail variance accounts. Deferral accounts include amounts recoverable and repayable. The amounts included in these accounts are deferred for accounting purposes because it is probable that they will be recovered (repaid) in future rates. Deferral accounts recognized at December 31, 2008 are disclosed in Note 10. The Company continually assesses the likelihood of the recovery of recoverable assets. If recovery is no longer considered probable, the amounts are charged to operations in the year the assessment is made. The recovery of regulatory assets commenced April 1, 2004.

(ii) Corporate taxes

Under the Electricity Act, 1998, the Company is required to make payments in lieu of income taxes (PILS) to the Ontario Electricity Financial Corporation (OEFC). As directed by the OEB, the Company provides for PILS payments using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts. Additional details related to the calculation and method of accounting for PILS is included in Notes 4 and 13.

(b) *Short-term investments*

Short term investments are carried at the lower of cost and market value.

2. **SIGNIFICANT ACCOUNTING POLICIES, continued**

(c) *Management estimates*

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

(d) *Foreign exchange*

Monetary assets and liabilities of the Company which are denominated in foreign currencies are translated at period end exchange rates. Other assets and liabilities are translated at rates in effect at the date the assets were acquired and liabilities incurred. Revenue and expenses are translated at the rates of exchange in effect at their transaction dates. The resulting gains or losses are included in operations.

(e) *Inventory*

Inventory is valued at the lower of cost and net realizable value with costs being determined on a weighted average basis.

(f) *Property, plant and equipment*

Property, plant and equipment are recorded at cost. The Company provides for amortization using the straight-line method at rates designed to amortize the cost of the property, plant and equipment over their estimated useful lives. The annual amortization rates are as follows:

Office and computer	5 to 10 years
Transmission and distribution systems	25 to 30 years
Transportation equipment	5 to 8 years
Operational equipment	10 to 15 years
Computer software	3 to 5 years
Leasehold improvements	10 years
Land rights	30 - 50 years
Buildings	25 to 30 years

Contributions for capital construction consist of third party contributions toward the cost of constructing distribution assets. The third party contribution is calculated through an economic evaluation as per the OEB Distribution Service Code. Contributed capital amounts are recorded as received and amortized over the same period as the asset to which they relate being 25 to 30 years.

2. SIGNIFICANT ACCOUNTING POLICIES, continued

(g) Asset retirement obligations

Canadian generally accepted accounting principles require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its fixed assets for an indefinite period, no removal costs can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations has not been made at this time.

(h) Related party transactions

Related party transactions are in the normal course of operations and have been measured at the exchange amount which is the amount of consideration established and agreed to by the related parties. Details of related party transactions and balances are detailed in Note 11.

(i) Employee future benefits

The Company pays certain health, dental and life insurance benefits on behalf of its retired employees. The Company recognizes these post-retirement costs in the period in which the employees earn the benefits. The cost of employee future benefits earned by employees is actuarially determined using the projected benefit method prorated on length of service and management's best estimate of salary escalation, retirement ages of employees, employee turnover and expected health and dental care costs. The most recent actuarial valuation of the obligation was performed for December 31, 2007. Details related to the post-employment benefits are detailed in Note 9.

(j) Revenue recognition

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 period. The related cost of power is recorded on the basis of the power billed by the Independent Electricity System Operator.

2. **SIGNIFICANT ACCOUNTING POLICIES, continued**

(k) Accounting changes

Capital disclosures

Effective January 1, 2008, the Company adopted a new accounting standard comprising CICA Handbook Section 1535, Capital Disclosures, requiring disclosure of the Company's objectives, policies, and processes for managing capital as well as its compliance with any external capital requirements. The implementation of this standard did not have any impact on the Company's results of operations or financial position. The disclosures are presented in note 17.

Inventories

Effective January 1, 2008, the Company adopted the CICA Handbook Section 3031, Inventories, recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense. The recommendations also clarified that major spare parts and stand-by equipment are to be reclassified to property, plant and equipment. The adoption of this policy has not resulted in a material change to the company's results of operations or financial position.

Financial Instruments

CICA Handbook sections 3862 - Financial Instruments - Disclosures and 3863 - Financial Instruments - Presentation requires disclosure of risks associated with both recognized and unrecognized financial instruments and the risks associated with those instruments. The implementation of the standards did not have any impact on the Company's results of operations or financial position. The disclosures are presented in note 18.

2. SIGNIFICANT ACCOUNTING POLICIES, continued

(l) Future accounting pronouncements

International Financial Reporting Standards (IFRS)

On February 13, 2008 the Accounting Standards Board (AcSB) confirmed that IFRS will be required to be adopted by publicly accountable enterprises and certain government enterprises for annual reporting purposes for fiscal years beginning on or after January 1, 2011. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010.

The Company is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. The International Accounting Standards Board has recently initiated a project to assess IFRS for rate regulated entities which may impact certain requirements for the Company in adopting IFRS. The Company does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required and any necessary system changes to gather and process the information.

Rate Regulated Entities

In 2007, the CICA amended section 1100 - Generally Accepted Accounting Principles to remove the temporary exception in the section pertaining to rate regulated accounting and requires the recognition of future income tax assets and liabilities. The effective date for the changes is for fiscal years beginning on or after January 1, 2009. The Company is currently in the process of evaluating the impact of these amendments on its financial statements.

3. SHORT-TERM INVESTMENTS

	2008 $	2007 $
Cash	2,257	-
Fixed Income Canadian bonds	1,014,400	-
International Bond and Income Fund	833,359	837,106
	1,850,016	837,106

The bonds are at rates of 4.25% and 4.69%. The market value of the investments at December 31, 2008 is $1,870,961 (2007 - $837,106).

4. INCOME TAXES RECEIVABLE

As described in Note 2(a), the Company is required to make payments-in-lieu of income taxes. Future income taxes are not recorded in the accounts since the Company follows the taxes payable method. The future tax asset balance is estimated at $3,972,000 (2007 - $4,300,000). This asset is determined by calculating the difference between the tax basis of the asset and its carrying amount on the balance sheet. Future tax assets are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to be recovered or settled. Details related to the income tax expense for the year, and components of the future income tax balance are included in note 13.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost $	Accumulated amortization $	2008 Net book value $	2007 Net book value $
Transmission and distribution systems	90,788,189	48,178,571	42,609,618	40,669,264
Transportation equipment	4,003,225	2,682,646	1,320,579	888,369
Land	3,104,515	-	3,104,515	2,570,347
Operational equipment	1,531,266	1,086,360	444,906	487,693
Computer software	1,465,482	1,058,957	406,525	584,315
Leasehold improvements	456,691	374,636	82,055	92,826
Land rights	463,812	116,308	347,504	133,879
Buildings	279,020	85,049	193,971	200,833
Office and computer equipment	1,191,010	813,310	377,700	318,926
	103,283,210	54,395,837	48,887,373	45,946,452

6. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2008 $	2007 $
Accounts payable - purchased power	5,281,959	4,695,754
Other accounts payable and accrued liabilities	3,139,686	2,205,542
Water and sewer billings payable	1,303,048	1,249,435
Credits on customer accounts	1,478,093	839,329
Independent Electric System Operator	69,202	432,845
	11,271,988	9,422,905

7. DIVIDEND PAYABLE

The dividend payable was declared by the shareholders of Newmarket Hydro Ltd. and Tay Hydro Electric Distribution Company Inc. prior to the amalgamation date. The balance of the dividend payable will be paid during 2009.

8. LONG-TERM DEBT

	2008 $	2007 $
Note payable, 6.25% - Town of Newmarket	22,000,000	22,000,000
Note payable, 6.25% - Township of Tay	1,742,821	1,742,821
Debenture payable - Township of Tay	200,000	436,000
	23,942,821	24,178,821
Less principal payments due within one year	200,000	200,000
Due beyond one year	23,742,821	23,978,821

The notes are unsecured and have no specific terms of repayment. Changes to the terms of the notes require 13 months notice. The notes are subordinated to IESO letters of credit referred to in Note 15.

The debenture is payable to the Township of Tay and bears interest at rates of 5.05% to 6%. Principal payments are due May 2009.

9. EMPLOYEE FUTURE BENEFITS

The Company provides certain health, dental and life insurance benefits for retired employees pursuant to the Company's policy. The accrued benefit obligation and net periodic expense for the year were determined by actuarial valuation. The most recent valuation was performed on December 31, 2007.

The transitional obligation resulting from the implementation of the policy is being amortized over the average remaining service life period of employees being, 11 years, with 2 years remaining to be amortized.

The past service cost obligation resulting from the inclusion of the former Tay Hydro Electric Distribution Company Inc. employees in the plan, is being amortized over the remaining service life of those employees, being 11 years with 10 years remaining to be amortized.

Significant actuarial assumptions employed for the valuations are as follows: future general inflation level of 2%, discount rate of 5%, salary and wage level increases at 3% per annum. For measurement purposes, a 10% annual increase in the per capita cost of health benefits was assumed for 2008. The rate was assumed to decrease annually by 1% to a rate of 5% for 2012 and thereafter. A 5% annual rate of increase in the per capita cost of covered dental costs was assumed for 2008 and thereafter. Information about the Company's defined benefit plan is included in the table which follows.

	2008 $	2007 $
Accrued Benefit Obligation, beginning of period	742,354	712,363
Current service cost	82,863	53,016
Amortization of the transitional obligation	37,727	25,151
Amortization of past service costs	13,204	8,803
Actuarial gain	-	(34,984)
Benefits paid	(36,291)	(21,995)
Accrued Benefit Obligation, end of period	839,857	742,354
Unamortized Transitional Obligation	75,454	113,181
Unamortized Past Pension Costs	123,237	136,441
Accrued Benefits Liability	1,038,548	991,976

10. DEFERRAL ACCOUNTS

As described in Note 2(a), the Company has recorded the following deferral accounts.

	2008 $	2007 $
Regulatory asset accounts approved for recovery - 2005 rates	4,163,254	4,163,254
Recovered to date	(5,456,575)	(4,256,958)
	(1,293,321)	(93,704)
Deferred qualifying transition costs	94,366	94,366
Power purchased for resale	(1,543,174)	(208,242)
Smart meters	(149,578)	(24,368)
Retail settlements	31,108	31,095
Other regulatory assets	13,943	59,607
	(2,846,656)	(141,246)

The Company has accumulated certain deferral accounts representing power purchased for resale less the revenue billed to its customers.

In addition to these deferral accounts, the Company has determined that there are certain other regulatory variance accounts that may be available for recovery. These include carrying costs, specific variance accounts and other costs such as pension and insurance charges that were not included in the original rate base. Although the Company has submitted an application for recovery of these amounts through rates, due to the uncertainty related to the future recovery these amounts have not been recorded in the deferral accounts. The total amount of unrecorded regulatory assets is approximately $4.3 million.

11. DUE TO RELATED PARTIES AND RELATED PARTY TRANSACTIONS

(a) During the period, the Company entered into transactions with its majority parent, Newmarket Hydro Holdings Inc. (NHHI) and with The Town of Newmarket which is the sole shareholder of Newmarket Hydro Holdings Inc. Revenue charged during the year included energy, street light capital and street light maintenance charged at commercial rates to the Town of Newmarket.

In addition, included in amounts payable (note 6) are water and sewer amounts collected which are due to the Town. These amounts are collected and remitted in accordance with a contract with URB Olameter and remitted on their behalf.

11. DUE TO RELATED PARTIES AND RELATED PARTY TRANSACTIONS, continued

(b) Transactions

Details of transactions with the Town of Newmarket during the period are as follows:

	2008 $	2007 $
Revenue		
Energy sales	2,261,180	1,005,823
Services - Street light capital	181,095	233,822
Services - Street light maintenance	224,396	156,929
	2,666,671	1,396,574
Expenses		
Interest	1,375,000	916,666
Rent, property tax and other	374,908	233,312
	1,749,908	1,149,978

(c) The following amounts due to/from the Town of Newmarket are included in the financial statements:

	2008 $	2007 $
Accounts receivable	360,739	300,614
Accounts payable	-	(1,132)
	360,739	299,482

(d) The following amounts due from related parties are included in accounts receivable:

	2008 $	2007 $
Newmarket Hydro Holdings Inc.	160,417	126,817
Tay Hydro Inc.	48,547	48,547
	208,964	175,364

12. **SHARE CAPITAL**

Authorized
Unlimited number of common shares

Issued

	2008 $	2007 $
10,000 common shares	27,140,206	27,140,206

13. **INCOME TAXES**

a) The components of future income tax balances are as follows:

	2008 $	2007 $
Future income tax asset		
Tax basis of equipment in excess of carrying amount	3,720,000	4,050,000
Reserves deductible when paid	252,000	250,000
	3,972,000	4,300,000

b) The provision for income taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 33.5% (2007 - 36.1%) to the income for the years as follows:

	2008 $	2007 $
Income for the year before income taxes	4,231,607	2,024,071
Anticipated income tax expense	1,417,588	730,690
Effect of items not deductible for tax purposes	3,350	3,610
Timing differences accounting amortization versus capital cost allowance	73,614	(13,301)
Loss on disposal of equipment not deductible for tax purposes	-	399,296
Timing differences of tax reserves	99,571	16,147
Other	13,873	(19,154)
Provision for income taxes	1,607,996	1,117,288

14. STATEMENT OF CASH FLOWS

	2008 $	2007 $
Increase in short-term investments	(1,012,910)	(837,106)
Decrease (increase) in accounts receivable	446,558	(7,214,300)
Increase in unbilled revenue	(832,015)	(8,069,714)
Increase in income taxes receivable	(315,891)	(464,109)
Increase in inventory	(161,657)	(995,482)
Decrease (increase) in prepaid and other	80,319	(379,805)
Increase in accounts payable and accrued liabilities	1,849,083	9,422,905
	53,487	(8,537,611)

Other information

Interest paid	1,503,931	1,007,463
Income taxes paid	2,160,000	1,796,100

15. SHORT TERM CREDIT FACILITIES

The Company has a $1,500,000 operating loan available from a major chartered bank. The facility is a 364 day revolving operating loan, bearing interest at prime, to be repaid within one year from date of acquisition unless extended by the bank. A standby fee of 10 basis points, payable quarterly in arrears applies to any unused portion of the facility. As at the balance sheet date, the Company has no balance outstanding on this facility. The operating loan includes restrictive clauses with respect to repayment.

In addition, the Company has provided prudential support in the amount of $2,765,940 to the Independent Electricity System Operator. The prudential support is secured by a letter of credit with a major chartered bank for $2,765,940 and contains restrictive clauses with respect to debt repayments.

A general security agreement covering all assets of the Company has been pledged as security.

16. PENSION AGREEMENT

The Company makes contributions to the Ontario Municipal Employees' Retirement Fund (O.M.E.R.S.), which is a multi-employer plan, on behalf of its employees. The plan is a defined benefit plan which specifies the amount of retirement benefits to be received by the employees based on the length of service and rates of pay.

The amount contributed to O.M.E.R.S. for the year ended was $271,138 (2007 - $181,651).

17. CAPITAL DISCLOSURES

The Company's primary objective when managing capital is to address the expectations as outlined in the Shareholder Agreement between the company's parent companies, Newmarket Hydro Holdings Inc. and its shareholder, the Town of Newmarket. The expectation is that the company will maintain a prudent financial structure in order to safeguard the Company's assets and to provide adequate returns for its shareholders and benefits to the stakeholders.

The Ontario Energy Board sets rates based on a deemed capital structure 60% debt and 40% equity.

Changes to the Company's capital structure are constrained by existing covenants contained in the banking agreement. The Company must maintain a maximum debt to capitalization ratio of .50 to 1 and maintain a debt service coverage ratio of 1.2. The Company's banking agreement also contains negative covenants that include restrictions on mergers and distribution of dividends in excess of free cash flow.

The Company's current capital structure is defined as follows:

	2008 $	2007 $
Long term debt	23,942,821	23,978,821

	2008 $	2007 $
Share capital	27,140,206	27,140,206
Retained earnings	3,530,394	906,783
	30,670,600	28,046,989

18. FINANCIAL INSTRUMENTS

The Company is exposed to the following risks in respect of certain of the financial instruments held:

(a) Fair value

Excluding the measurement of assets and liabilities subject to rate regulation, which are not subject to a fair value assessment, the following classes of financial assets and liabilities are recorded:

Current assets and liabilities

Cash and equivalents are classified as assets held-for-trading. Accounts receivable are classified as loans and receivables. Accounts payable and accrued liabilities, and long- term debt are classified as other financial liabilities. The carrying value of the accounts receivable, accounts payable and accruals and short term debt approximates their fair value due to their short-term nature.

Advances from related parties

The Company initially recorded the promissory notes from related parties (note 8) at the exchange amount and classified the amounts as other financial liabilities. In applying the effective interest rate method, the fair value of that instrument does not differ from its carrying value.

(b) Credit risk

Credit risk arises from the potential that a counter party will fail to perform its obligations. The Company is exposed to credit risk from customers. However, the Company has a significant number of customers which minimizes concentration of credit risk. An allowance for collection of doubtful accounts in the amount of $298,882 (2007- $111,562) has been recorded.

(c) Interest rate risk

The Company is not exposed to any significant interest rate risk.

(d) Currency risk

Currency risk is the risk to the Company's earnings that arises from fluctuations of foreign exchange rates and the degree of volatility of these rates. The Company is not exposed to significant currency risk.

19. COMMITMENTS

Pursuant to the Ontario Energy Board's EB-2005-0315, the Company was instructed to participate in the construction of the Holland Junction transformer station in order to provide additional electricity supply to the northern York region. The total cost of the Holland Junction transformer station is estimated to be $13.85 million., The Company's share of the cost is estimated to be $5 million. Costs of approximately $922,000 (2007 -$nil) related to the project were incurred in 2008.

The Government of the Province of Ontario through Ontario Regulations 428/06, 427/06 and 426/06 has identified the Company as a priority "Smart Meter" implementation area. The Company has spent approximately $4.9 million (2007 - $4 million) to December 31, 2008 related to the implementation.

20. CONTINGENCIES

(a) In the normal course of business, the Company enters into agreements that meet the definition of a guarantee. The guarantees include indemnities under lease agreements, purchase and sale agreements, confidentiality agreements, outsourcing, service and information agreements. The nature of these indemnification agreements prevents the Company from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability related to the likelihood and predictability of future events. Historically, the Company has not made any significant payments under similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

(b) Indemnity has been provided to all directors and/or officers of the Company for various items including, but not limited to, all costs to settle suits or actions due to association with the Company, subject to certain restrictions. The Company has purchased directors' and officers' liability insurance to mitigate the cost of any potential suits or actions. The amount of any potential future liability which exceeds the amount of insurance coverage cannot reasonably be determined.

(c) The Company participates with other municipal utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electric Association Reciprocal Insurance Exchange. Under this agreement, the Company is contingently liable for additional assessments to the extent that premiums collected are not sufficient to cover actual losses, claims and costs experienced.

20. **CONTINGENCIES, continued**

(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 a representative of the Defendant Class consisting of all municipal electric utilities in Ontario that have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in municipal electrical utilities receiving interest at effectives rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Electricity Distributors Association is undertaking the defence of this class action. At this time it is not possible to quantify the effect, if any, on these financial statements, and as such no accrual of any potential liability has been recognized.

FINANCIAL STATEMENTS OF

NEWMARKET-TAY POWER DISTRIBUTION LTD.

December 31, 2009

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Chartered Accountants

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AUDITORS' REPORT

To the Shareholders of
Newmarket-Tay Power Distribution Ltd.

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

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of 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.

Collins Barrow Kawarthas LLP

Chartered Accountants
Licensed Public Accountants

Peterborough, Ontario
March 19, 2010

NEWMARKET-TAY POWER DISTRIBUTION LTD.

BALANCE SHEET

As at December 31, 2009

	2009 $	2008 $
ASSETS		
Current assets		
Cash and short-term investments (note 3)	7,385,208	8,670,543
Accounts receivable	5,909,415	6,607,325
Unbilled revenue	9,526,065	8,901,729
Income taxes receivable	637,771	780,000
Inventory	841,717	1,157,139
Due from parent company	-	160,417
Prepaid expenses	720,450	299,575
	25,020,626	26,576,728
Other assets		
Property, plant and equipment (note 4)	50,541,162	48,887,283
Future income taxes (note 11)	4,650,000	-
	55,191,162	48,887,283
	80,211,788	75,464,011

The accompanying notes are an integral part of these financial statements

NEWMARKET-TAY POWER DISTRIBUTION LTD.
BALANCE SHEET
As at December 31, 2009

	2009 $	2008 $
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities (note 5)	9,910,648	11,271,987
Dividend payable	-	1,665,000
Current portion of deposits held	377,586	377,586
Current portion of long-term debt (note 8)	-	200,000
	10,288,234	13,514,573
Long-term liabilities		
Deposits held	3,887,556	3,849,504
Deferral accounts (note 6)	952,566	2,846,656
Employee future benefits (note 7)	938,049	839,857
Long-term debt (note 8)	23,742,821	23,742,821
Advances from parent company (note 10)	1,779,566	-
	31,300,558	31,278,838
	41,588,792	44,793,411
Shareholders' equity		
Share capital (note 9)	27,140,206	27,140,206
Retained earnings	11,482,790	3,530,394
	38,622,996	30,670,600
	80,211,788	75,464,011

Approved on behalf of the Board

____________________ Director ____________________ Director

The accompanying notes are an integral part of these financial statements

NEWMARKET-TAY POWER DISTRIBUTION LTD.
STATEMENT OF RETAINED EARNINGS
For the year ended December 31, 2009

	2009 $	2008 $
Retained earnings - beginning of year, as previously stated	3,530,394	906,783
Adoption of accounting policy (note 2.b)	4,600,000	-
Retained earnings, as restated	8,130,394	906,783
Net income for the year	3,352,396	2,623,611
Retained earnings - end of year	11,482,790	3,530,394

The accompanying notes are an integral part of these financial statements

NEWMARKET-TAY POWER DISTRIBUTION LTD.
STATEMENT OF INCOME
For the year ended December 31, 2009

	2009 $	2008 $
Sales	69,333,579	68,759,205
Cost of sales	54,537,190	53,679,660
Gross profit	14,796,389	15,079,545
Expenses		
Customer billing and collecting	1,836,647	1,737,748
Amortization	4,270,472	4,082,048
Interest - long term debt	1,567,359	1,503,931
Administration	2,510,941	2,446,541
Property and capital taxes	246,309	260,277
System operation and maintenance	2,197,730	1,843,973
	12,629,458	11,874,518
Income before undernoted items and income taxes	2,166,931	3,205,027
Other income		
Service and retailer charges	159,333	155,403
Interest	97,758	185,756
Rental and other	160,589	192,706
Occupancy, connection and collection fees	524,494	492,715
Deferral account recovery (note 6)	1,972,083	-
	2,914,257	1,026,580
Income before income taxes	5,081,188	4,231,607
Provision for (recovery of) income taxes (note 11)		
Current	1,778,792	1,607,996
Future	(50,000)	-
	1,728,792	1,607,996
Net income for the year	3,352,396	2,623,611

The accompanying notes are an integral part of these financial statements

NEWMARKET-TAY POWER DISTRIBUTION LTD.
STATEMENT OF CASH FLOWS
For the year ended December 31, 2009

	2009 $	2008 $
CASH PROVIDED FROM (USED FOR)		
Operating activities		
Net income for the year	3,352,396	2,623,611
Items not affecting cash		
Amortization	4,270,472	4,082,048
Future income taxes	(50,000)	-
Employee future benefits	98,192	97,503
Loss on disposal of property, plant and equipment	995	-
	7,672,055	6,803,162
Change in non-cash working capital items (note 12)	(1,250,989)	1,099,997
	6,421,066	7,903,159
Investing activities		
Purchase of property, plant and equipment	(5,925,346)	(7,022,969)
Deferral accounts	(1,894,090)	2,705,410
Decrease in dividend payable	(1,665,000)	(1,665,000)
	(9,484,436)	(5,982,559)
Financing activities		
Advances from/to parent company	1,939,983	(33,600)
Deposits held	38,052	(451,463)
Repayment of long-term debt	(200,000)	(236,000)
	1,778,035	(721,063)
Increase (decrease) in cash	(1,285,335)	1,199,537
Cash - beginning of year	8,670,543	7,471,006
Cash - end of year	7,385,208	8,670,543
Other information		
Interest paid	1,524,162	1,503,931
Income taxes paid	1,800,000	2,160,000

The accompanying notes are an integral part of these financial statements

1. NATURE OF OPERATIONS

Newmarket-Tay Power Distribution Ltd. (the Company) is a subsidiary of Newmarket Hydro Holdings Inc. and was formed as a result of the amalgamation of Newmarket Hydro Ltd. and Tay Hydro Electric Distribution Company Inc. on May 1, 2007. Tay Hydro Inc. has a 7% non-controlling interest in the Company.

The principal activity of the Company is to distribute electricity to the residents and businesses in the Town of Newmarket and the Township of Tay under licence issued by the Ontario Energy Board (OEB). The Company is regulated by the OEB and adjustments to its distribution rates require OEB approval.

2. SIGNIFICANT ACCOUNTING POLICIES

(a) Electricity regulation

The Company is subject to rate regulation by the Ontario Energy Board (OEB). The OEB is charged with the responsibility of approving rates for the transmission and distribution of electricity. The following regulatory policy is practiced in a rate regulated environment:

Deferral accounts

Deferral accounts consist of deferred qualifying transition costs and various rate and retail variance accounts. Deferral accounts include amounts recoverable and repayable. The amounts included in these accounts are deferred for accounting purposes because it is probable that they will be recovered (repaid) in future rates. Deferral accounts recognized at December 31, 2009 are disclosed in note 6. The Company continually assesses the likelihood of the recovery of recoverable assets. If recovery is no longer considered probable, the amounts are charged to operations in the year the assessment is made.

(b) Adoption of accounting policy

Effective January 1, 2008 the CICA amended Section 3465, Income Taxes, to require the recognition of future income tax liabilities and assets by rate regulated entities effective for fiscal years beginning on or after January 1, 2009. The adoption of the standard resulted in a recognition of a future tax asset of $4,600,000 and an adjustment to retained earnings of $4,600,000.

(c) Short-term investments

Short term investments are carried at the lower of cost and market value.

(d) Inventory

Inventory is valued at the lower of cost and net realizable value with costs being determined on a weighted average basis.

2. **SIGNIFICANT ACCOUNTING POLICIES, continued**

(e) *Property, plant and equipment*

Property, plant and equipment are recorded at cost. The Company provides for amortization using the straight-line method at rates designed to amortize the cost of the property, plant and equipment over their estimated useful lives. The annual amortization rates are as follows:

Buildings	25 to 30 years
Transmission and distribution	25 to 30 years
Office and computer	5 to 10 years
Leasehold improvements	10 years
Computer software	3 to 5 years
Operational equipment	10 to 15 years
Transportation equipment	5 to 8 years
Land rights	30 - 50 years

Contributions for capital construction consist of third party contributions toward the cost of constructing distribution assets. The third party contribution is calculated through an economic evaluation as per the OEB Distribution Service Code. Contributed capital amounts are recorded as received and amortized over the same period as the asset to which they relate being 25 to 30 years.

(f) *Related party transactions*

Related party transactions are in the normal course of operations and have been measured at the exchange amount which is the amount of consideration established and agreed to by the related parties. Details of related party transactions and balances are disclosed in note 10.

(g) *Employee future benefits*

The Company pays certain health, dental and life insurance benefits on behalf of its retired employees. The Company recognizes these post-retirement costs in the period in which the employees earn the benefits. The cost of employee future benefits earned by employees is actuarially determined using the projected benefit method prorated on length of service and management's best estimate of salary escalation, retirement ages of employees, employee turnover and expected health and dental care costs. The most recent actuarial valuation of the obligation was performed for December 31, 2007. Details related to the post-employment benefits are detailed in note 7.

2. **SIGNIFICANT ACCOUNTING POLICIES, continued**

(h) *Corporate income taxes*

Under the Electricity Act, 1998, the Company is required to make payments in lieu of income taxes (PILS) to the Ontario Electricity Financial Corporation (OEFC). Future income taxes are calculated using the liability method of tax accounting. In providing for corporate income taxes, temporary differences between the tax basis of assets or liabilities and their carrying amounts are reflected as future income taxes. The tax rates anticipated to be in effect when these temporary differences reverse are used to calculate future income taxes. Additional details related to the calculation and method of accounting for PILS is included in note 11.

(i) *Management estimates*

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

(j) *Revenue recognition*

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 period. The related cost of power is recorded on the basis of the power billed by the Independent Electricity System Operator.

(k) *Foreign exchange*

Monetary assets and liabilities of the Company which are denominated in foreign currencies are translated at year end exchange rates. Other assets and liabilities are translated at rates in effect at the date the assets were acquired and liabilities incurred. Revenue and expenses are translated at the rates of exchange in effect at their transaction dates. The resulting gains or losses are included in operations.

(l) *Asset retirement obligations*

Canadian generally accepted accounting principles require the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets on retirement. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures.

Some of the Company's assets may have asset retirement obligations. As the Company expects to use the majority of its fixed assets for an indefinite period, no removal costs can be determined and, consequently, a reasonable estimate of the fair value of any asset retirement obligations has not been made at this time.

2. **SIGNIFICANT ACCOUNTING POLICIES, continued**

(m) Comparative amounts

The financial statements have been reclassified, where applicable, to conform to the presentation used in the current year. The changes do not affect prior year earnings.

(n) Future accounting pronouncements

International Financial Reporting Standards (IFRS)

On February 13, 2008 the Accounting Standards Board (AcSB) confirmed that IFRS will be required to be adopted by publicly accountable enterprises and certain government enterprises for annual reporting purposes for fiscal years beginning on or after January 1, 2011. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010.

The Company is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. The International Accounting Standards Board has recently initiated a project to assess IFRS for rate regulated entities which may impact certain requirements for the Company in adopting IFRS. The Company does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required and any necessary system changes to gather and process the information.

3. **CASH AND SHORT-TERM INVESTMENTS**

The cash balance includes cash and short term investments as follows:

	2009 $	2008 $
Cash	4,483,727	6,820,527
Short term investments	2,901,481	1,850,016
	7,385,208	8,670,543

The short term investments consist of bonds at rates of 4.25% and 4.69%. The market value of these bonds at December 31 is $2,947,281 (2008 - $1,870,961).

4. PROPERTY, PLANT AND EQUIPMENT

	Cost $	Accumulated amortization $	2009 Net book value $	2008 Net book value $
Land	3,128,229	-	3,128,229	3,104,425
Buildings	297,912	92,289	205,623	193,971
Transmission and distribution	92,667,006	48,498,880	44,168,126	42,609,618
Office and computer equipment	1,235,723	910,955	324,768	377,700
Leasehold improvements	710,826	415,980	294,846	82,055
Computer software	1,503,797	1,263,519	240,278	406,525
Operational equipment	1,550,229	1,160,930	389,299	444,906
Transportation equipment	4,218,188	2,887,497	1,330,691	1,320,579
Land rights	589,802	130,500	459,302	347,504
	105,901,712	55,360,550	50,541,162	48,887,283

5. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2009 $	2008 $
Accounts payable - purchased power	5,023,659	5,281,958
Other accounts payable and accrued liabilities	2,292,109	3,139,686
Water and sewer billings payable	1,107,151	1,303,048
Credits on customer accounts	1,413,431	1,478,093
Independent Electric System Operator	74,298	69,202
	9,910,648	11,271,987

6. DEFERRAL ACCOUNTS

As described in note 2(a), the Company has recorded the following deferral accounts.

	2009 $	2008 $
Deferral accounts approved for recovery	4,386,254	4,163,254
Recovered to date	(4,179,798)	(5,456,575)
	206,456	(1,293,321)
Power purchased for resale	(1,093,097)	(1,543,174)
Smart meters	(88,428)	(149,578)
Retail settlements	8,607	31,108
Other deferral accounts	13,896	108,279
	(952,566)	(2,846,686)

The Company has accumulated certain deferral accounts representing power purchased for resale less the revenue billed to its customers.

The Company submitted an application in 2009 to the Ontario Energy Board for recovery of prior years' deferral account balances. The Company was approved to recover those deferral balances; some of which had not been recorded due to the uncertainty of recovery. These unrecorded amounts included certain carrying costs, specific variance accounts and other costs such as pension and insurance costs. These amounts total income of $2,641,205 and expenses of $669,112. The net amount of $1,972,083 is recognized as income and in deferral accounts accounts approved and recovered.

7. EMPLOYEE FUTURE BENEFITS

The Company provides certain health, dental and life insurance benefits for retired employees pursuant to the Company's policy. The accrued benefit obligation and net periodic expense for the year were determined by actuarial valuation. The most recent valuation was performed for December 31, 2007.

The transitional obligation resulting from the implementation of the policy is being amortized over the average remaining service life period of employees being, 11 years, with 1 year remaining to be amortized.

The past service cost obligation resulting from the inclusion of the former Tay Hydro Electric Distribution Company Inc. employees in the plan, is being amortized over the remaining service life of those employees, being 11 years with 9 years remaining to be amortized.

Significant actuarial assumptions employed for the valuations are as follows: future general inflation level of 2%, discount rate of 5%, salary and wage level increases at 3% per annum. For measurement purposes, a 10% annual increase in the per capita cost of health benefits was assumed for 2009. The rate was assumed to decrease annually by 1% to a rate of 5% for 2012 and thereafter. A 5% annual rate of increase in the per capita cost of covered dental costs was assumed for 2008 and thereafter. Information about the Company's defined benefit plan is included in the table which follows.

	2009 $	2008 $
Accrued benefit obligation, beginning of period	839,857	742,354
Current service cost	86,818	82,863
Amortization of the transitional obligation	37,727	37,727
Amortization of past service costs	13,204	13,204
Benefits paid	(39,557)	(36,291)
Accrued benefit obligation, end of period	938,049	839,857
Unamortized transitional obligation	37,727	75,454
Unamortized past pension costs	110,033	123,237
	1,085,809	1,038,548

8. LONG-TERM DEBT

	2009 $	2008 $
Note payable, 6.25% - Town of Newmarket	22,000,000	22,000,000
Note payable, 6.25% - Township of Tay	1,742,821	1,742,821
Debenture payable - Township of Tay	-	200,000
	23,742,821	23,942,821
Less principal payments due within one year	-	200,000
Due beyond one year	23,742,821	23,742,821

The notes are unsecured and have no specific terms of repayment. Changes to the terms of the notes require 13 months notice. The notes are subordinated to Independent Electricity System Operator letters of credit referred to in note 13.

9. SHARE CAPITAL

Authorized

Unlimited number of common shares

Issued

	2009 $	2008 $
10,000 common shares	27,140,206	27,140,206

10. DUE TO RELATED PARTY AND RELATED PARTY TRANSACTIONS

(a) During the period, the Company entered into transactions with its majority parent, Newmarket Hydro Holdings Inc. (NHHI) and with The Town of Newmarket which is the sole shareholder of Newmarket Hydro Holdings Inc. Revenue charged during the year included energy, street light capital and street light maintenance charged at commercial rates to the Town of Newmarket.

Included in accounts payable, as detailed in note 5, are water and sewer amounts collected which are due to the Town. These amounts are collected and remitted in accordance with a contract with URB Olameter and remitted on their behalf.

(b) Transactions

Details of transactions with the Town of Newmarket during the year are as follows:

	2009 $	2008 $
Revenue		
Energy sales	2,423,241	2,261,180
Services - Street light capital	195,969	181,095
Services - Street light maintenance	224,396	224,396
	2,843,606	2,666,671
Expenses		
Interest	1,375,000	1,375,000
Rent, property tax and other	373,148	374,908
	1,748,148	1,749,908

(c) The following amounts due from (to) the Town of Newmarket are included in the financial statements:

	2009 $	2008 $
Accounts receivable	339,637	360,739
Accounts payable	(457)	-
	339,180	360,739

10. DUE TO RELATED PARTY AND RELATED PARTY TRANSACTIONS, continued

(d) The following amounts are due from (to) the parent company:

	2009 $	2008 $
Newmarket Hydro Holdings Inc.	(1,779,566)	160,417
Tay Hydro Inc	-	48,547
	(1,779,566)	208,964

Advances from the parent company; Newmarket Hydro Holdings Inc. is unsecured and has no specific terms of repayment. The note may be called with 13 months notice. Interest is calculated at the OEB deemed debt rate of 6.1% for 2009.

11. INCOME TAXES

a) The components of future income tax balances are as follows:

	2009 $	2008 $
Future income tax asset		
Tax basis of equipment in excess of carrying amount	3,826,000	-
Reserves deductible when paid	401,000	-
Cumulative eligible capital available for tax purposes	423,000	-
	4,650,000	-

b) The provision for income taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 33% (2008 - 33.5%) to the income for the years as follows:

	2009 $	2008 $
Income for the year before income taxes	5,081,000	4,232,000
Anticipated income tax expense	1,676,730	1,417,720
Effect of items not deductible for tax purposes	7,425	3,350
Timing differences accounting amortization versus capital cost allowance	7,831	73,614
Timing differences of tax reserves	42,168	99,571
Other	(5,362)	13,741
Income tax expense	1,728,792	1,607,996

12. CHANGE IN NON-CASH WORKING CAPITAL ITEMS

	2009 $	2008 $
Decrease in accounts receivable	697,910	480,158
Increase in unbilled revenue	(624,336)	(832,015)
Decrease (increase) in income taxes receivable	142,229	(315,891)
Decrease (increase) in inventory	315,422	(161,657)
Decrease (increase) in prepaid expenses	(420,875)	80,320
Increase (decrease) in accounts payable and accrued liabilities	(1,361,339)	1,849,082
	(1,250,989)	1,099,997

13. SHORT TERM CREDIT FACILITIES

The Company has a $1,500,000 operating loan available from a major chartered bank. The facility is a 364 day revolving operating loan, bearing interest at prime, to be repaid within one year from date of acquisition unless extended by the bank. A standby fee of 10 basis points, payable quarterly in arrears applies to any unused portion of the facility. As at the balance sheet date, the Company has no balance outstanding on this facility. The operating loan includes restrictive clauses with respect to repayment.

In addition, the Company has provided prudential support in the amount of $2,765,940 to the Independent Electricity System Operator. The prudential support is secured by a letter of credit with a major chartered bank for $2,765,940 and contains restrictive clauses with respect to debt repayments.

A general security agreement covering all assets of the Company has been pledged as security.

14. PENSION AGREEMENT

The Company makes contributions to the Ontario Municipal Employees' Retirement Fund (O.M.E.R.S.), which is a multi-employer plan, on behalf of its employees. The plan is a defined benefit plan which specifies the amount of retirement benefits to be received by the employees based on the length of service and rates of pay.

The amount contributed to O.M.E.R.S. for the year ended was $276,644 (2008 - $271,138)

15. CAPITAL DISCLOSURES

The Company's primary objective when managing capital is to address the expectations as outlined in the Shareholder Agreement between the Company's parent companies, Newmarket Hydro Holdings Inc. and its shareholder, the Town of Newmarket. The expectation is that the Company will maintain a prudent financial structure in order to safeguard the Company's assets and to provide adequate returns for its shareholders and benefits to the stakeholders.

The Ontario Energy Board sets rates based on a deemed capital structure 60% debt and 40% equity.

Changes to the Company's capital structure are constrained by existing covenants contained in the banking agreement. The Company must maintain a maximum debt to capitalization ratio of 0.50 to 1 and maintain a debt service coverage ratio of 1.2. The Company's banking agreement also contains negative covenants that include restrictions on mergers and distribution of dividends in excess of free cash flow.

The Company's current capital structure is defined as follows:

	2009 $	2008 $
Long term debt	23,742,821	23,942,821
	23,742,821	23,942,821

	2009 $	2008 $
Share capital	27,140,206	27,140,206
Retained earnings	11,482,790	3,530,394
	38,622,996	30,670,600

16. **FINANCIAL INSTRUMENTS**

The Company is exposed to the following risks in respect of certain of the financial instruments held:

(a) Fair value

Excluding the measurement of assets and liabilities subject to rate regulation, which are not subject to a fair value assessment, the following classes of financial assets and liabilities are recorded:

Current assets and liabilities

Cash and equivalents are classified as assets held-for-trading. Accounts receivable are classified as loans and receivables. Accounts payable and accrued liabilities, due to parent Company and long- term debt are classified as other financial liabilities. The carrying value of the accounts receivable and accounts payable and accrued liabilities approximate their fair value due to their short-term nature.

Advances to parent company

The fair value of the amounts due to parent company (note 11) are less than carrying value, as the amounts are non-interest bearing. As the amounts have no terms of repayment, the fair value cannot be calculated with any degree of certainty.

(b) Interest rate risk

The Company is exposed to interest rate risk related to the variable rate operating loan, as detailed in note 14.

(c) Credit risk

Credit risk arises from the potential that a counter party will fail to perform its obligations. The Company is exposed to credit risk from customers. However, the Company has a significant number of customers which minimizes concentration of credit risk. An allowance for collection of doubtful accounts in the amount of $355,935 (2008 - $298,882) has been recorded.

(d) Currency risk

Currency risk is the risk to the Company's earnings that arises from fluctuations of foreign exchange rates and the degree of volatility of these rates. The Company is not exposed to significant currency risk.

17. COMMITMENTS

Pursuant to the Ontario Energy Board's EB-2005-0315, the Company was instructed to participate in the construction of the Holland Junction transformer station in order to provide additional electricity supply to the northern York region. The total cost of the Holland Junction transformer station is estimated to be $13.85 million. The Company's share of the cost is estimated to be $5 million. Costs of $1,304,413 (2008 - $922,000) related to the project were incurred in 2009.

18. CONTINGENCIES

(a) In the normal course of business, the Company enters into agreements that meet the definition of a guarantee. The guarantees include indemnities under lease agreements, purchase and sale agreements, confidentiality agreements, outsourcing, service and information agreements. The nature of these indemnification agreements prevents the Company from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability related to the likelihood and predictability of future events. Historically, the Company has not made any significant payments under similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

(b) Indemnity has been provided to all directors and/or officers of the Company for various items including, but not limited to, all costs to settle suits or actions due to association with the Company, subject to certain restrictions. The Company has purchased directors' and officers' liability insurance to mitigate the cost of any potential suits or actions. The amount of any potential future liability which exceeds the amount of insurance coverage cannot reasonably be determined.

(c) The Company participates with other municipal utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electric Association Reciprocal Insurance Exchange. Under this agreement, the Company is contingently liable for additional assessments to the extent that premiums collected are not sufficient to cover actual losses, claims and costs experienced.

(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 a representative of the Defendant Class consisting of all municipal electric utilities in Ontario that have charged late payment charges on overdue utility bills at any time after April 1, 1981. The claim is that late payment penalties result in municipal electrical utilities receiving interest at effectives rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

Subsequent to year end there has been a proposed settlement to the class action lawsuit in the amount of $95,803. This amount has been accrued in the 2009 financial statements.

Attachment 1 (of 1):

2006-2009 Account Balances

2006

NEWMARKET

Account #	ACC_NAME	YTD Actual
10050	Cash In Bank	7,835,638.16
10051	Payroll Bank Account	-
10052	U S Bank Account	10,608.08
10053	U S Exchange	1,910.00
10100	Permanent Cash Advances	-
10110	Temporary Cash Advances	-
10600	Term Deposits	-
10700	Current Investments	805,305.25
10701	Current Investments premium	-
11000	Customer Accounts Receivable	5,912,290.20
11100	Other Accounts Receivable	701,552.97
11101	AR-Municipal St Lt Maintenance	65,124.86
11102	AR-Billing Adjustments	-
11103	AR-Customer Time Payments	-
11104	AR-Recoverable Work	44,745.22
11105	AR- OMERS Overpayment	-
11106	AR-Accounts to Clo Agent	-
11107	Suspense	-
11108	Consumer Deposits Suspense	-
11109	Accounts Receivable Suspense	-
11110	Letters of Credit Suspense	-
11111	AR-Municipal St Lt Capital	40,046.24
11112	AR-NHHI	(233,634.37)
11113	1443393 Ont Inc	-
11114	Retirements	-

TAY

Account #	ACC_NAME	YTD Actual
10050	Cash In Bank	1,130,850.84
10051	Payroll Bank Account	200.00
10052	U S Bank Account	-
10053	U S Exchange	-
10100	Permanent Cash Advances	-
10110	Temporary Cash Advances	-
10600	Term Deposits	-
10700	Current Investments	-
10701	Current Investments premium	-
11000	Customer Accounts Receivable	271,143.80
11100	Other Accounts Receivable	113,232.21
11101	AR-Municipal St Lt Maintenance	-
11102	AR-Billing Adjustments	-
11103	AR-Customer Time Payments	-
11104	AR-Recoverable Work	-
11105	AR- OMERS Overpayment	-
11106	AR-Accounts to Clo Agent	-
11107	Suspense	-
11108	Consumer Deposits Suspense	-
11109	Accounts Receivable Suspense	-
11110	Letters of Credit Suspense	-
11111	AR-Municipal St Lt Capital	-
11112	AR-NHHI	64,337.86
11113	1443393 Ont Inc	1,555.63
11114	2006 EDR Receivable	1,602.36

11200	Unbilled Revenue	6,608,773.06	11200	Unbilled Revenue	622,622.30
11300	Allowance for Doubtful Acct	(272,123.63)	11300	Allowance for Doubtful Acct	(5,508.54)
11700	Notes Receivable	-	11700	Notes Receivable	-
11800	Prepaid Expense	209,937.12	11800	Prepaid Expense	44,553.31
11801	Leased Vehicles	-	11801	Leased Vehicles	-
11802	Upper Canada Energy Alliance	(1,372.39)	11802	Upper Canada Energy Alliance	-
11803	Prepaid Expense- ERA	-	11803	Prepaid Expense- ERA	-
11900	Other Current Assets	1,395.00	11900	Other Current Assets	-
13300	Inventory	1,140,908.73	13300	Inventory	137,980.08
13301	Inventory-Suspense	-	13301	Inventory-Suspense	-
13302	Inventory-Default	-	13302	Inventory-Default	-
13400	Inventory - Water St Retail	-	13400	Inventory - Water St Retail	-
14600	Long Term Rec-Billing Adj	1,647.57	14600	Long Term Rec-Billing Adj	-
14601	LT Rec - OMERS Overpayment	-	14601	LT Rec - OMERS Overpayment	-
14602	LT Rec - Cust Time Payment	-	14602	LT Rec - Cust Time Payment	-
15080	Other Regulatory Assets	-	15080	Other Regulatory Assets	44,011.91
15087	Other Regulatory Assets-CC	-	15087	Other Regulatory Assets-CC	2,350.80
15180	Retail Cost Variance - Retail	-	15180	Retail Cost Variance - Retail	(942.83)
15187	Retail Cost Var -Retail CC	-	15187	Retail Cost Var -Retail CC	-
15250	Deferred Charges	36,593.13	15250	Misc Deferred Debits	2,170.51
15251	Misc Deferred Debits - CC	-	15251	Misc Deferred Debits - CC	-
15252	Deferred Charges-Amortization	-	15252	Deferred Charges-Amortization	-
15253	UCEA Inc	-	15253	UCEA Inc	-
15254	Deferred Charges-Recovery	(22,089.53)	15254	Deferred Charges-Recovery	-
15480	Retail Cost Variance - STR	-	15480	Retail Cost Variance - STR	1,280.33
15487	Retail Cost Variance - STR-CC	-	15487	Retail Cost Variance - STR-CC	-
15500	Low Voltage Variance-Revenue	-	15500	Low Voltage Variance-Revenue	(21,526.13)
15501	Low Voltage Variance-Costs	-	15501	Low Voltage Variance-Costs	63,978.22

15502	LV METERING CHARGE	0.00
15503	LV METERING MNTHLY CHARGE	0.00
15507	Low Voltage Variance-CC	-
15550	Smart Meter Capital Expenditur	-
15551	Smart Meter Cap/Rec Offset Var	-
15560	Smart Meter - OM&A	-
15551	Smart Meter - OM&A Revenue	-
15567	Smart Meter - OM&A CC	-
15620	Deferred PILS	-
15627	Deferred PILS - CC	-
15630	Deferred PILS - Contra	-
15637	Deferred PILS - Contra-CC	-
15650	Conserve & Demand Revenue	-
15651	Gateway Project	-
15652	Residential	112,933.35
15653	Affordable/Social Housing	16,374.09
15654	Small Business	-
15655	Business/Commerical/Industrial	13,378.43
15656	Education Program	104,836.33
15657	Other Programs/Discretionary	75,350.09
15658	Distributions System studies	-
15659	Program Develop & Monitoring	117,600.00
15660	C&DM Recovered From Customers	(1,267,000.00)
15700	Transition Costs	454,785.60
15701	Transition Costs - Recovery	(273,428.02)
15707	Transition Costs - CC	0.00
15710	Pre Market Energy	15,890,354.44
15711	Pre Market Energy-Residential	(5,395,085.75)

15502	LV METERING CHARGE	0.00
15503	LV METERING MNTHLY CHARGE	0.00
15507	Low Voltage Variance-CC	44.84
15550	Smart Meter Capital Expenditur	-
15551	Smart Meter Cap/Rec Offset Var	(7,266.83)
15560	Smart Meter - OM&A	-
15551	Smart Meter - OM&A Revenue	-
15567	Smart Meter - OM&A CC	-
15620	Deferred PILS	123,821.40
15627	Deferred PILS - CC	(2,233.29)
15630	Deferred PILS - Contra	(122,678.22)
15637	Deferred PILS - Contra-CC	1,090.11
15650	Conserve & Demand Revenue	-
15651	Gateway Project	-
15652	Residential	-
15653	Affordable/Social Housing	-
15654	Small Business	-
15655	Business/Commerical/Industrial	-
15656	Education Program	10,646.13
15657	Other Programs/Discretionary	28,450.00
15658	Distributions System studies	-
15659	Program Develop & Monitoring	2,712.70
15660	C&DM Recovered From Customers	(40,325.33)
15700	Transition Costs	4,808.52
15701	Transition Costs - Recovery	-
15707	Transition Costs - CC	0.00
15710	Pre Market Energy	-
15711	Pre Market Energy-Residential	-

15712	Pre Market Energy-GS LT 50	(2,432,721.24)	15712	Pre Market Energy-GS LT 50	-
15713	Pre Market Energy-GS GT 50 kW	(1,072,344.70)	15713	Pre Market Energy-GS GT 50 kW	-
15714	Pre Market Energy-GS GT 50 kWh	(5,513,942.76)	15714	Pre Market Energy-GS GT 50 kWh	-
15715	Pre Market Energy-Street Light	(130,735.47)	15715	Pre Market Energy-Street Light	-
15716	Pre Market Energy-Sentinel Lts	(10,624.88)	15716	Pre Market Energy-Sentinel Lts	-
15718	Pre Market - Variance Recovery	(1,004,284.98)	15718	Pre Market - Variance Recovery	-
15800	RSVA-Whlsle Market Serv Rev	(19,612,059.17)	15800	RSVA-Whlsle Market Serv Rev	(839,936.98)
15801	RSVA-Whlsle Market Serv Chg	18,917,145.47	15801	RSVA-Whlsle Market Serv Chg	855,087.87
15802	RSVA-WMS Fixed Chg Settltment	1,872,473.40	15802	RSVA-WMS Fixed Chg Settltment	-
15807	RSVA-WMS CC	-	15807	RSVA-WMS CC	440.17
15808	RSVA-WMS - Recovery	(751,347.30)	15808	RSVA-WMS - Recovery	-
15809	RSVA-WMS Unbilled	(434,040.20)	15809	RSVA-WMS Unbilled	-
15820	RSVA-One Time Charges-Revenue	-	15820	RSVA-One Time Charges-Revenue	-
15821	RSVA-One Time Charges-Charges	127,351.56	15821	RSVA-One Time Charges-Charges	(2,427.88)
15827	RSVA-One Time -CC	-	15827	RSVA-One Time -CC	691.80
15840	RSVA-Trans Network Revenue	(16,601,754.30)	15840	RSVA-Trans Network Revenue	(730,471.44)
15841	RSVA-Trans Network Charges	18,323,164.94	15841	RSVA-Trans Network Charges	468,889.46
15842	RSVA-Trans Meter Credit	(29,450.00)	15842	RSVA-Trans Meter Credit	
15847	RSVA-Trans Network CC	-	15847	RSVA-Trans Network CC	(1,263.37)
15848	RSVA-Trans Network Recovery	(292,035.61)	15848	RSVA-Trans Network Recovery	-
15849	RSVA-Trans Network Unbilled	-	15849	RSVA-Trans Network Unbilled	-
15860	RSVA-Trans Connection Revenue	(14,411,222.30)	15860	RSVA-Trans Connection Revenue	(647,552.03)
15861	RSVA-Trans Connection Charges	15,168,937.34	15861	RSVA-Trans Connection Charges	206,403.46
15867	RSVA-Trans Connection CC	-	15867	RSVA-Trans Connection CC	(27,307.74)
15868	RSVA-Trans Connection Recovery	(167,527.25)	15868	RSVA-Trans Connection Recovery	-
15869	RSVA-Trans Unbilled	(702,401.81)	15869	RSVA-Trans Unbilled	-
15880	RSVA-Power Pd By Customers	(98,699,679.68)	15880	RSVA-Power Pd By Customers	(2,734,454.65)
15881	RSVA-Power purchase IESO	187,279,505.38	15881	RSVA-Power purchase IESO	7,624,118.75
15882	Spot Price Pd By Customers	(84,287,806.12)	15882	Spot Price Pd By Customers	-

15883	Fixed Price Pd By Customers	(81,532,098.25)	15883	Fixed Price Pd By Customers	(4,619,283.94)
15884	Fixed Price Variance Account	95,613,695.10	15884	Fixed Price Variance Account	-
15885	Fixed Price IMO Settlement	(9,214,668.26)	15885	Fixed Price IMO Settlement	-
15886	Fixed Price Time of Use Rates	(41,265.01)	15886	Fixed Price Time of Use Rates	-
15887	RSVA - Power - CC	-	15887	RSVA - Power - CC	20,274.58
15888	RSVA - Energy Recovery	0.01	15888	RSVA - Energy Recovery	-
15889	RSVA-Power Unbilled	(3,944,404.04)	15889	RSVA-Power Unbilled	96.10
15890	Pre-Market & RSVA Clearing	(465,462.67)	15890	Pre-Market & RSVA Clearing	-
15900	Approved Reg Assets	-	15900	Approved Reg Assets	716,661.00
15901	Approved Reg Assets - Recovery	-	15901	Approved Reg Assets - Recovery	(441,146.90)
15907	Approved Reg Assets -CC	-	15907	Approved Reg Assets -CC	-
15950	Approved Deferral Balance-2008	-	15950	Approved Deferral Balance-2008	-
15951	APPROVED DEFERRALRECOVERY2008	-	15951	APPROVED DEFERRALRECOVERY2008	-
15952	APPROVED SM RECOVERY-2008	-	15952	APPROVED SM RECOVERY-2008	-
15956	Approved CC to be Recovered-08	-	15956	Approved CC to be Recovered-08	-
15957	Approved Deferral CC-2008	-	15957	Approved Deferral CC-2008	-
15959	Unbilled Deferral & Smart M.	-	15959	Unbilled Deferral & Smart M.	-
15990	Regulated Price Plan Settlemen	(3,399,240.70)	15990	Regulated Price Plan Settlemen	-
15991	Reg Price Plan retailer settl	(377,741.76)	15991	Reg Price Plan retailer settl	-
15993	Global Adj - CC	-	15993	Global Adj - CC	(260.25)
15994	Global Adj Payabe re lRPP	-	15994	Global Adj Payabe re lRPP	-
15995	Global adjustment	1,263,542.98	15995	Global adjustment	(20,665.66)
15996	Global Adj Settlement Amount	(2,501,987.22)	15996	Global Adj Settlement Amount	-
15997	RPP Adj Settlement Amount	(157,852.42)	15997	RPP Adj Settlement Amount	-
16060	Organization Costs	161,233.99	16060	Organization Costs	(32,960.23)
18050	Distribution-Land	2,460,709.06	18050	Distribution-Land	58066.87
18060	Distribution-Land Rights	-	18060	Distribution-Land Rights	241736.72
18200	Dist Stn-Rec Complex	77,383.00	18200	Dist Stn-Rec Complex	-

18201	Dist Stn-Legge	551,050.91	18201	Dist Stn-Legge	-
18202	Dist Stn-Thompson	930,481.42	18202	Dist Stn-Thompson	-
18203	Dist Stn-Broughton/Simmons	1,057,175.69	18203	Dist Stn-Broughton/Simmons	-
18204	Dist Stn-Gilbert	1,120,932.57	18204	Dist Stn-Gilbert	-
18205	Dist Stn-Andrews	1,112,596.98	18205	Dist Stn-Andrews	-
18206	Dist Stn-Leadbeater	685,581.35	18206	Dist Stn-Leadbeater	-
18207	Dist Stn-Cook	467,053.80	18207	Dist Stn-Cook	-
18208	Dist Stn-Twinney	1,261,278.66	18208	Dist Stn-Twinney	-
18209	Dist Stn-S/E Quadrant	523,899.57	18209	Dist Stn-S/E Quadrant	-
18210	Dist Stn-Miscellaneous	15,244.78	18210	Dist Stn-Miscellaneous	-
18211	Dist Stn Port McNicholl	-	18211	Dist Stn Port McNicholl	108,779.51
18212	Dist Stn Victoria Harbour	-	18212	Dist Stn Victoria Harbour	285,843.55
18213	Dist Stn Waubaushene	-	18213	Dist Stn Waubaushene	98,161.72
18214	Port McNicholl MS 2	0.00	18214	Port McNicholl MS 2	0.00
18300	Dist Lines O/H Poles	10,817,893.38	18300	Dist Lines O/H Poles	1,401,244.99
18301	Inventory Holding - O/H Poles	-	18301	Inventory Holding - O/H Poles	-
18350	Dist Lines O/H Conductor	13,538,608.02	18350	Dist Lines O/H Conductor	1,407,424.85
18351	Invent. Holding- O/H Conductor	-	18351	Invent. Holding- O/H Conductor	-
18400	Dist Lines U/G Conduit	6,703,409.14	18400	Dist Lines U/G Conduit	246,218.03
18401	Inventory Holding-U/G Conduit	-	18401	Inventory Holding-U/G Conduit	-
18450	Dist Lines U/G Conductor	21,777,586.01	18450	Dist Lines U/G Conductor	233,342.83
18451	Invent. Holding-U/G Conductor	-	18451	Invent. Holding-U/G Conductor	-
18500	Distribution Transformers	13,240,544.02	18500	Distribution Transformers	986,751.16
18501	Invent. Holding-Transformers	-	18501	Invent. Holding-Transformers	-
18550	Services	3,021,290.94	18550	Services	1,198,967.22
18551	44 KV CAPITAL STUDY	6,530.26	18551	44 KV CAPITAL STUDY	-
18552	13.8 KV CAPITAL STUDY	2,517.15	18552	13.8 KV CAPITAL STUDY	-
18600	Distribution Meters	5,876,373.31	18600	Distribution Meters	360,896.69
18610	Smart Meters	-	18610	Smart Meters	-

18650	Wholesale Meters	919,634.49	18650	Wholesale Meters	-
18750	Distribution Street Lights	-	18750	Distribution Street Lights	-
18990	Capital Asset Management	-	18990	Capital Asset Management	-
189999	Capital Holding Account	-	189999	Capital Holding Account	-
19050	General Plant - Land	89.70	19050	General Plant - Land	
19080	Buildings-Eagle Street	-	19080	Buildings-Eagle Street	276,277.15
19081	Leasehold Imp-Steven Court	390,126.33	19081	Leasehold Imp-Steven Court	-
19082	Buildings-Water Street	-	19082	Buildings-Water Street	-
19083	Buildings-Other	-	19083	Buildings-Other	-
19150	Office Equipment	236,679.33	19150	Office Equipment	49,775.70
19200	Computer Hardware	585,881.28	19200	Computer Hardware	66,565.70
19250	Computer Software	944,826.07	19250	Computer Software	105,761.58
19300	Transportation Equipment	2,802,289.21	19300	Transportation Equipment	333,865.01
19350	Stores Equipment	140,871.20	19350	Stores Equipment	6,384.82
19400	Tools, Shop & Garage Equipment	403,794.25	19400	Tools, Shop & Garage Equipment	65,240.34
19450	Measurement & Testing Equip	88,487.88	19450	Measurement & Testing Equip	-
19650	Water Heater Rental units	-	19650	Water Heater Rental units	-
19800	System Supervisory Equipment	723,684.20	19800	System Supervisory Equipment	-
19810	System Optimization Study	10,871.57	19810	System Optimization Study	-
19850	Sentinel Light Rental Units	13,085.27	19850	Sentinel Light Rental Units	9,966.47
19900	Amalco Capital	-	19900	Amalco Capital	-
19950	Cont Cap to be Amortized	(12,548,042.00)	19950	Cont Cap to be Amortized	(297,502.09)
199999	Fixed Assets Suspense	0.00	199999	Fixed Assets Suspense	-
20550	Construction In Progress	0.00	20550	Construction In Progress	-
21050	Accum Dep-Current Provision	0.00	21050	Accum Dep-Current Provision	-
21051	Accum Amor-Organization Costs	(161,234.00)	21051	Accum Amor-Organization Costs	(11,044.00)
21052	Accum Amor-Buildings Other	0.00	21052	Accum Amor-Buildings Other	(71,331.77)
21053	Accum Amor-Stations	(3,761,509.69)	21053	Accum Amor-Stations	(252,667.44)

21054	Accum Amor-O/H Lines	(11,178,953.26)	21054	Accum Amor-O/H Lines	(1,895,141.04)
21055	Accum Amor-Land Rights	0.00	21055	Accum Amor-Land Rights	(103,087.01)
21056	Accum Amor-U/G Lines	(13,754,190.54)	21056	Accum Amor-U/G Lines	(758,345.95)
21057	Accum Amor-Transformers	(6,122,332.69)	21057	Accum Amor-Transformers	(583,074.65)
21058	Accum Amor-Meters	(2,963,774.92)	21058	Accum Amor-Meters	(241,913.64)
21059	Accum Amor-Street Lights	0.00	21059	Accum Amor-Street Lights	-
21060	Accum Amor-Office Equipment	(145,167.19)	21060	Accum Amor-Office Equipment	(45,833.55)
21061	Accum Amor-Computer Equipment	(414,215.37)	21061	Accum Amor-Computer Equipment	(42,588.49)
21062	Accum Amor-Computer Software	(479,598.97)	21062	Accum Amor-Computer Software	(95,715.43)
21063	Accum Amor-Stores Equipment	(86,682.38)	21063	Accum Amor-Stores Equipment	(6,143.40)
21064	Accum Amor-Transportation Equi	(2,062,066.91)	21064	Accum Amor-Transportation Equi	(288,365.41)
21065	Accum Amor-Tools	(319,899.80)	21065	Accum Amor-Tools	(54,463.12)
21066	Accum Amor-Water Heaters	0.00	21066	Accum Amor-Water Heaters	-
21067	Accum Amor-Leasehold	(280,386.44)	21067	Accum Amor-Leasehold	
21068	Accum Amor-System Supervisory	(430,932.14)	21068	Accum Amor-System Supervisory	-
21069	Accum Amor-Sentinel Lights	(12,581.84)	21069	Accum Amor-Sentinel Lights	(9,966.47)
21070	Accum Amor-Street Lights	0.00	21070	Accum Amor-Street Lights	-
21090	Accum Amor-Cont Cap	2,006,440.82	21090	Accum Amor-Cont Cap	19,519.19
22050	Accounts Payable	(956,161.81)	22050	Accounts Payable	(643,435.37)
22051	A/P-Town Water Billing	(1,106,304.10)	22051	A/P-Town Water Billing	-
22052	A/P-Power Bill	(4,164,711.20)	22052	A/P-Power Bill	-
22053	A/P-Income Tax	(238,077.61)	22053	A/P-Income Tax	(181,010.24)
22054	Miscellaneous Accruals	(167,144.07)	22054	Miscellaneous Accruals	(43,482.91)
22055	A/P-MPMA Rebate	(66,610.68)	22055	A/P-MPMA Rebate	2,871.15
22056	A/P-Phase 2 Rebate	0.00	22056	A/P-Phase 2 Rebate	-
22057	A/P-$75 Rebate	0.00	22057	A/P-$75 Rebate	-
22058	Accounts Payable-Default	0.00	22058	Accounts Payable-Default	13,800.00
22059	A/P-Town Other	0.12	22059	A/P-Town Other	-
22060	Invoice Settlement-Direct	0.00	22060	Invoice Settlement-Direct	-

22061	BRC - Toronto Hydro	0.00	22061	BRC - Toronto Hydro	-
22062	BRC - OPG	0.00	22062	BRC - OPG	-
22063	BRC - Ontario Hydro	0.00	22063	BRC - Ontario Hydro	-
22064	BRC - First Source	0.00	22064	BRC - First Source	-
22065	BRC - Ontario Electric Savings	0.00	22065	BRC - Ontario Electric Savings	-
22066	BRC - Coral Energy	0.00	22066	BRC - Coral Energy	-
22067	BRC - Canadian Choice Energy	0.00	22067	BRC - Canadian Choice Energy	-
22068	BRC - Constellation New Energy	0.00	22068	BRC - Constellation New Energy	-
22069	BRC - Universal Energy	0.00	22069	BRC - Universal Energy	-
22070	BRC - ECNG	0.00	22070	BRC - ECNG	-
22071	BRC -Canadian Hydro	0.00	22071	BRC -Canadian Hydro	-
22072	BRC - Bullfrog Power	0.00	22072	BRC - Bullfrog Power	-
22073	BRC - SEMINC	0.00	22073	BRC - SEMINC	-
22074	BRC - Superior Energy	0.00	22074	BRC - Superior Energy	-
22075	BRC - Wholesale Energy	0.00	22075	BRC - Wholesale Energy	-
22076	BRC - Planet Energy Ontario Co	0.00	22076	BRC - Planet Energy Ontario Co	-
22077	BRC - AG ENERGY CO-OP LTD	0.00	22077	BRC - AG ENERGY CO-OP LTD	-
22078	BRC - National Energy Corp.	0.00	22078	BRC - National Energy Corp.	-
22080	Customer Credit Balances	(770,982.00)	22080	Customer Credit Balances	(89,130.44)
22100	Customer Deposits-Current	(300,000.00)	22100	Customer Deposits-Current	-
22200	Unused Vacation Pay Accrual	(66,423.48)	22200	Unused Vacation Pay Accrual	(25,965.69)
22201	Payroll Clearing	(119,688.48)	22201	Payroll Clearing	(8,436.27)
222011	Interco due to & due from	-	222011	Interco due to & due from	-
22202	Subdivider Lot Levies-Current	(52,586.00)	22202	Subdivider Lot Levies-Current	-
22250	Other Current Liabilities	-	22250	Other Current Liabilities	(3,316.90)
22251	Notes and Loans Payable	-	22251	Notes and Loans Payable	-
22500	Debt Retirement Charges	-	22500	Debt Retirement Charges	(37,124.99)
22560	AP - IMO	-	22560	AP - IMO	-

22600	Current Portion Long Term Debt	-	22600	Current Portion Long Term Debt	-
22601	Current Portion Other Debt	-	22601	Current Portion Other Debt	-
22640	OPA - Refrigerator Roundup	-	22640	OPA - Refrigerator Roundup	(30,021.00)
22641	OPA - Summer Savings	-	22641	OPA - Summer Savings	-
22642	OPA - Peaksaver	-	22642	OPA - Peaksaver	-
226421	OPA - ERIP	-	226421	OPA - ERIP	-
226422	OPA-Direct Installs	-	226422	OPA-Direct Installs	-
226423	OPA-Comm Initiative Fund	-	226423	OPA-Comm Initiative Fund	-
226424	OPA - MEER	-	226424	OPA - MEER	-
22643	Thermostats - Barrie	-	22643	Thermostats - Barrie	-
22644	Thermostats - Innisfil	-	22644	Thermostats - Innisfil	-
22645	Thermostats -Essex	-	22645	Thermostats -Essex	-
22646	Thermostats -Enwin	-	22646	Thermostats -Enwin	-
22647	Thermostats -Erie Thames	-	22647	Thermostats -Erie Thames	-
22648	Thermostats -St Thomas	-	22648	Thermostats -St Thomas	-
22649	Thermostats -Clinton	-	22649	Thermostats -Clinton	-
22650	Thermostats -West Perth	-	22650	Thermostats -West Perth	-
22680	Accrued Interest-L T Debt	-	22680	Accrued Interest-L T Debt	-
22681	Accrued Interest-Cust Deps	(1,457.57)	22681	Accrued Interest-Cust Deps	(9,435.96)
22901	GST - ITC 100%	(493.18)	22901	GST - ITC 100%	(6,113.08)
22902	GST - ITC 57.14% St Lts	-	22902	GST - ITC 57.14% St Lts	-
22903	GST - ITC 50%	-	22903	GST - ITC 50%	-
22904	GST - Collected	-	22904	GST - Collected	2,781.69
22905	GST - Remittance	-	22905	GST - Remittance	-
22909	PST Payable	(1,204.65)	22909	PST Payable	-
22921	Income Tax Payable	0.00	22921	Income Tax Payable	7.33
22922	CPP Payable	0.00	22922	CPP Payable	-
22923	Employment Insurance Payable	0.00	22923	Employment Insurance Payable	-

22924	OMERS Payable	0.00	22924	OMERS Payable	-
22925	EHT Payable	0.00	22925	EHT Payable	-
22926	W.S.I.B. Payable	0.00	22926	W.S.I.B. Payable	-
22927	Life Insurance Payable	(10,826.57)	22927	Life Insurance Payable	-
22928	Garnishee Payable	0.00	22928	Garnishee Payable	-
22929	Union Dues	0.00	22929	Union Dues	-
229291	RRSP Payable	0.00	229291	RRSP Payable	-
23060	Employee Future Benefits	(704,943.00)	23060	Employee Future Benefits	-
23200	Other Non-Current Liabilities	-	23200	Other Non-Current Liabilities	-
23201	Deferred Credits	-	23201	Deferred Credits	-
23300	Subdividers Lot Levies	-	23300	Subdividers Lot Levies	-
23301	Lot Levies-Single Units	-	23301	Lot Levies-Single Units	-
23350	Customer Deposits	(2,367,035.79)	23350	Customer Deposits	(133,696.37)
23351	Construction Deposits	(339,889.90)	23351	Construction Deposits	-
23352	Retailer Deposits	(51,786.48)	23352	Retailer Deposits	-
23353	Consumer Deposit Suspense	(5,900.00)	23353	Consumer Deposit Suspense	-
24050	Other Regulatory Liabilities	0.00	24050	Other Regulatory Liabilities	-
25000	Long Term Debt	0.00	25000	Long Term Debt	(436,000.00)
25200	Long Term Debt - Town	(22,000,000.00)	25200	Long Term Debt - Town	(1,952,821.00)
30220	Lot Levies Transf'd to Equity	(201,720.00)	30220	Lot Levies Transf'd to Equity	-
30300	Contributed Capital-Equity	(33,468,574.15)	30300	Contributed Capital-Equity	(1,742,821.00)
30301	Contributed Capital-St Lts	0.00	30301	Contributed Capital-St Lts	-
30450	Accumulated Net Income	4,098,294.76	30450	Accumulated Net Income	(382,940.94)
30451	Dividends Paid	2,858,000.00	30451	Dividends Paid	321,000.00
30490	Dividends Declared		30490	Dividends Declared	-
40060	Energy-Residential	(1,169.19)	40060	Energy-Residential	-
40061	Residential-Dist Customer Chg	(3,751,507.04)	40061	Residential-Dist Customer Chg	(673,725.48)
40062	Residential-Dist kWh	(3,517,689.54)	40062	Residential-Dist kWh	(344,725.97)

40063	Residential-Energy kWh	0.00	40063	Residential-Energy kWh	-
40064	Residential-Retro Adjustment	0.00	40064	Residential-Retro Adjustment	7,266.83
40068	Energy-Res-PILS Trans Recovery	122,517.45	40068	Energy-Res-PILS Trans Recovery	-
40250	Energy-Street Lights	(754.18)	40250	Energy-Street Lights	-
40251	Energy-Sentinel Lights	0.00	40251	Energy-Sentinel Lights	-
40252	Street Light-Dist kW Charge	(26,907.19)	40252	Street Light-Dist kW Charge	(5,541.87)
40253	Street Light-Energy kW Charge	0.00	40253	Street Light-Energy kW Charge	(4,459.12)
40254	Street Light-Retro Adj	0.00	40254	Street Light-Retro Adj	-
40255	Street Light-Dist Fixed Chg	(25,343.74)	40255	Street Light-Dist Fixed Chg	-
40258	St Light-PIL Trans Recovery	933.32	40258	St Light-PIL Trans Recovery	-
40302	Sentinel Light Distribution kW	(3,085.68)	40302	Sentinel Light Distribution kW	(176.23)
40303	Sentinel Light Energy kW	0.00	40303	Sentinel Light Energy kW	(123.56)
40305	Sentinel Light Service Charge	(8,582.84)	40305	Sentinel Light Service Charge	-
40308	Sent Lt PILS Trans Recovery	223.85	40308	Sent Lt PILS Trans Recovery	-
40350	GT 50 - Dist Electric Meter Ad	(14,169.40)	40350	GT 50 - Dist Electric Meter Ad	-
40351	GS LT 50-Dist Cust Chg	(662,635.12)	40351	GS LT 50-Dist Cust Chg	(50,656.11)
40352	GS LT 50-Dist kWh Charge	(1,667,188.25)	40352	GS LT 50-Dist kWh Charge	(83,019.72)
40353	GS LT 50-Energy kWh Charge	0.00	40353	GS LT 50-Energy kWh Charge	-
40354	GS LT 50-PIL Trans Recovery	39,898.12	40354	GS LT 50-PIL Trans Recovery	-
40355	GS GT 50-Dist Cust Charge	(1,650,873.93)	40355	GS GT 50-Dist Cust Charge	(85,491.33)
40356	GS GT 50-Dist kW Charge	(3,133,024.68)	40356	GS GT 50-Dist kW Charge	(40,058.43)
40357	GS GT 50-Energy kW Charge	0.00	40357	GS GT 50-Energy kW Charge	(133,188.77)
40358	GS GT 50-PIL Trans Recovery	102,945.81	40358	GS GT 50-PIL Trans Recovery	-
40359	GS GT 50-Retro Adj	0.00	40359	GS GT 50-Retro Adj	-
40360	C&DM Recovered From Customers	0.00	40360	C&DM Recovered From Customers	-
40500	Energy-Adjustments	(182,969.32)	40500	Energy-Adjustments	2,141.50
40550	Smart Meter Revenue Rec'd	0.00	40550	Smart Meter Revenue Rec'd	-
40551	WAP/R - Direct	0.00	40551	WAP/R - Direct	-

40552	WAP/GS - Direct	0.00	40552	WAP/GS - Direct	-
40553	WAP/R - THESI	0.00	40553	WAP/R - THESI	-
40554	WAP/GS - THESI	0.00	40554	WAP/GS - THESI	-
40555	WAP/R - OPG	0.00	40555	WAP/R - OPG	-
40556	WAP/GS - OPG	0.00	40556	WAP/GS - OPG	-
40557	WAP/R - OHE	0.00	40557	WAP/R - OHE	-
40558	WAP/GS - OHE	0.00	40558	WAP/GS - OHE	-
40559	WAP/R - First Source	0.00	40559	WAP/R - First Source	-
40560	WAP/GS - First Source	0.00	40560	WAP/GS - First Source	-
40561	WAP/R - Coral Energy	0.00	40561	WAP/R - Coral Energy	-
40562	WAP/GS - Coral Energy	0.00	40562	WAP/GS - Coral Energy	-
40563	WAP/R - OESC	0.00	40563	WAP/R - OESC	-
40564	WAP/GS - OESC	0.00	40564	WAP/GS - OESC	-
40565	WAP/R - Cdn Choice	0.00	40565	WAP/R - Cdn Choice	-
40566	WAP/GS - Cdn Choice	0.00	40566	WAP/GS - Cdn Choice	-
40620	Whlsl Mrkt Services Billed	0.00	40620	Whlsl Mrkt Services Billed	-
40640	Whlsl Mrkt Srvcs Blld 1 time	0.00	40640	Whlsl Mrkt Srvcs Blld 1 time	-
40660	Retail Transmission Service	0.00	40660	Retail Transmission Service	-
40680	Retail Transmission Connection	0.00	40680	Retail Transmission Connection	-
40800	SSS Administration Charge	(90,663.99)	40800	SSS Administration Charge	(13,317.82)
40801	Distribution Wheeling Service	0.00	40801	Distribution Wheeling Service	-
40802	Recver Reg Assets prev W/O	0.00	40802	Recver Reg Assets prev W/O	-
40820	Retail Service Revenues	(36,369.20)	40820	Retail Service Revenues	-
40840	STR Revenues	(1,684.75)	40840	STR Revenues	(272.48)
42103	Revenue-Pole Rentals	(60,762.85)	42103	Revenue-Pole Rentals	(71,113.60)
42250	Revenue-Late Payment Charges	(173,270.62)	42250	Revenue-Late Payment Charges	(8,673.04)
42350	Revenue-St LT Non-Energy	0.00	42350	Revenue-St LT Non-Energy	-
42351	Account Setup	(54,337.50)	42351	Account Setup	-

42352	Revenue-Reconnection Charges	(21,985.00)	42352	Revenue-Reconnection Charges	(13,733.00)
42353	Revenue-Collection Charges	(148,705.50)	42353	Revenue-Collection Charges	(2,377.64)
42354	Change of Occupancy-Final Bill	(46,287.50)	42354	Change of Occupancy-Final Bill	-
43102	Revenue-Sentinel Lt Rentals	(7,166.66)	43102	Revenue-Sentinel Lt Rentals	(1,733.70)
43250	Revenue-Sale of Scrap Metals	(20,463.87)	43250	Revenue-Sale of Scrap Metals	-
43251	Water St-Mark Up on Sales	0.00	43251	Water St-Mark Up on Sales	-
43550	Gain on Sale of Assets	(48,270.58)	43550	Gain on Sale of Assets	(1,627.82)
43600	Loss on Sale of Assets	-	43600	Loss on Sale of Assets	132.96
43850	Non-Utility Rental Income	-	43850	Non-Utility Rental Income	-
43851	Water Heater Rental Income	-	43851	Water Heater Rental Income	-
43900	Revenue-Miscellaneous	(9,906.17)	43900	Revenue-Miscellaneous	(3,069.09)
43901	Revenue-Profit on Mat & Serv	(15,303.59)	43901	Revenue-Profit on Mat & Serv	-
43902	Revenue-Arrears Certificates	(2,328.50)	43902	Revenue-Arrears Certificates	-
43903	Revenue-Power Bill Aggregation	0.00	43903	Revenue-Power Bill Aggregation	-
43904	Costs re By-passed Meters	24,096.80	43904	Costs re By-passed Meters	-
43905	Revenue re By-passed Meters	(4,872.30)	43905	Revenue re By-passed Meters	-
44050	Interest Earned	(496,202.01)	44050	Interest Earned	(50,012.77)
44051	CC on Reg Assets	0.00	44051	CC on Reg Assets	(20,141.20)
47050	Pre Market & RSVA Clearing	0.00	47050	Pre Market & RSVA Clearing	-
47051	Transition Cost Write Off	0.00	47051	Transition Cost Write Off	-
47080	Power Purchased - WMS	(9,085.72)	47080	Power Purchased - WMS	-
47100	Power Purchased-Adjustments	0.00	47100	Power Purchased-Adjustments	-
47120	Power Purchased - On Time	0.00	47120	Power Purchased - On Time	-
47140	Power Purchased - Network	0.00	47140	Power Purchased - Network	225,347.72
47160	Power Purchased - Connection	0.00	47160	Power Purchased - Connection	209,460.44
47250	Competition Transition Charges	0.00	47250	Competition Transition Charges	-
50050	Operation Supervision	0.00	50050	Operation Supervision	-
50160	Substn Op'n-Labour	12,138.77	50160	Substn Op'n-Labour	1,653.56

50161	Substn Op'n-Inspect & Tes	15,050.26	50161	Substn Op'n-Inspect & Tes	1,583.89
50170	Substn Op'n-Supplies & Expense	-	50170	Substn Op'n-Supplies & Expense	-
50200	O/H Line Operation-Labour	354,256.54	50200	O/H Line Operation-Labour	5,898.42
50250	O/H Line Op'n-Supplies & Exp	1,598.77	50250	O/H Line Op'n-Supplies & Exp	2,503.93
50350	O/H Dist Transformer Operation	10,407.11	50350	O/H Dist Transformer Operation	-
50400	U/G Line Op'n-Labour	117,221.77	50400	U/G Line Op'n-Labour	-
50401	U/G Line Op'n-Stakeouts	128,355.75	50401	U/G Line Op'n-Stakeouts	-
50450	U/G Line Op'n-Supplies & Exp	11,138.09	50450	U/G Line Op'n-Supplies & Exp	-
50451	U/G Line Op'n-Stakeouts	0.00	50451	U/G Line Op'n-Stakeouts	-
50550	U/G Dist Transformer Operation	64,433.94	50550	U/G Dist Transformer Operation	-
50551	Dist Trans - Inspect & Test	374.65	50551	Dist Trans - Inspect & Test	-
50650	Dist Meters-Reverification	115,704.61	50650	Dist Meters-Reverification	11,191.93
50651	Dist Meters-Dispute Test	336.48	50651	Dist Meters-Dispute Test	-
50652	Dist Meters-Seal Extension	10,221.77	50652	Dist Meters-Seal Extension	-
50653	Dist Meters-Technical Training	334.64	50653	Dist Meters-Technical Training	-
50654	Dist Meters-Computer Costs	0.00	50654	Dist Meters-Computer Costs	-
50655	Dist Meters-Other	60.99	50655	Dist Meters-Other	6,844.01
50701	Customer Premises-Stakeouts	33,973.14	50701	Customer Premises-Stakeouts	18,197.82
50702	Customer Fire & No Power Calls	27,318.93	50702	Customer Fire & No Power Calls	-
50703	Customer Station Maintenance	13,780.11	50703	Customer Station Maintenance	1,981.94
50800	Engineering & Operations	0.00	50800	Engineering & Operations	20,268.13
50801	Engineering & Ops Training	16,798.56	50801	Engineering & Ops Training	24.00
50950	O/H Lines Op-Rentals Paid	10,512.93	50950	O/H Lines Op-Rentals Paid	10,280.06
51140	Substation Maintenance	4,409.41	51140	Substation Maintenance	-
51141	Substn Mtce-Land & Building	9,561.02	51141	Substn Mtce-Land & Building	-
51142	Substn Mtce-Other	703.25	51142	Substn Mtce-Other	77,312.56
51200	O/H Line Mtce-Poles	163,186.83	51200	O/H Line Mtce-Poles	-
51201	O/H Line Mtce-Temp Services	13,427.48	51201	O/H Line Mtce-Temp Services	-
51250	O/H Line Mtce-Conductor	133,060.75	51250	O/H Line Mtce-Conductor	26,067.10

51251	O/H Line Mtce-Insul Washing	23,317.20	51251	O/H Line Mtce-Insul Washing	-
51252	O/H Line Mtce-Serv Upgrades	60,940.65	51252	O/H Line Mtce-Serv Upgrades	-
51254	O/H Line Mtce-Other	117.50	51254	O/H Line Mtce-Other	9,809.54
51350	Tree Trimming & ROW Mtce	56,661.13	51350	Tree Trimming & ROW Mtce	-
51450	U/G Line Mtce-Conduit	40,285.15	51450	U/G Line Mtce-Conduit	730.80
51500	U/G Line Mtce-Cable	169,814.62	51500	U/G Line Mtce-Cable	-
51501	U/G Line Mtce-Other	374.50	51501	U/G Line Mtce-Other	-
51600	Dist Transformer Mtce	42,404.35	51600	Dist Transformer Mtce	3,811.27
51601	Dist Transformer Painting	1,979.27	51601	Dist Transformer Painting	-
51602	Dist Transformer Other	0.00	51602	Dist Transformer Other	-
51700	Sentinel Light Mtce - Labour	0.00	51700	Sentinel Light Mtce - Labour	-
51720	Sentinel Lt Mtce - Mat & ExP	0.00	51720	Sentinel Lt Mtce - Mat & ExP	-
51750	Dist Meter Maintenance	(1,489.86)	51750	Dist Meter Maintenance	25.36
53050	Bill & Collect - Supervision	100,505.40	53050	Bill & Collect - Supervision	6,039.35
53100	Reading-Labour, Vehicles & Exp	(273.48)	53100	Reading-Labour, Vehicles & Exp	10,778.73
53101	Reading-Contract Services	138,944.84	53101	Reading-Contract Services	49,733.41
53102	Reading-Supplies	-	53102	Reading-Supplies	22.50
53109	Reading-Other	-	53109	Reading-Other	-
53150	Billing-Labour & Expenses	100,102.52	53150	Billing-Labour & Expenses	26,325.84
53151	Billing-Postage	176,811.73	53151	Billing-Postage	23,390.62
53152	Billing-Stationery & Supplies	9,688.67	53152	Billing-Stationery & Supplies	5,722.75
53153	Billing-Computer Expenses	43,344.60	53153	Billing-Computer Expenses	25,933.61
53154	Billing-Equipment Costs	0.00	53154	Billing-Equipment Costs	-
53155	Billing-Printing & Stuffing	40,191.18	53155	Billing-Printing & Stuffing	8,416.60
53156	Billing-Contract Delivery	0.00	53156	Billing-Contract Delivery	-
53159	Billing-Other	120,513.03	53159	Billing-Other	12,468.34
53200	Collecting-Lab, Vehicles $ Exp	428,846.89	53200	Collecting-Lab, Vehicles $ Exp	45,029.52
53201	Collecting-Postage	22,814.94	53201	Collecting-Postage	-
53202	Collecting-Stationery & Suppli	10,996.33	53202	Collecting-Stationery & Suppli	765.31

53203	Collecting-Equipment Costs	0.00	53203	Collecting-Equipment Costs	272.48
53205	Collecting-Visa/Bank Card	1,571.65	53205	Collecting-Visa/Bank Card	200.00
53209	Collecting-Other	52,880.03	53209	Collecting-Other	(449.10)
53250	Collecting-Cash Over & Short	335.11	53250	Collecting-Cash Over & Short	0.10
53350	Billing-Bad Debts	37,705.13	53350	Billing-Bad Debts	2,260.13
53351	Billing-Conversion Adjustments	0.00	53351	Billing-Conversion Adjustments	-
53550	Billing-Bad Debts	0.00	53550	Billing-Bad Debts	-
54100	Community Relations-Xmas Lts	4,838.95	54100	Community Relations-Xmas Lts	-
54101	Community Relations-Other	88,971.98	54101	Community Relations-Other	7,059.34
55150	Sales Exp-Advertising	6,493.30	55150	Sales Exp-Advertising	390.00
56051	Director's Lab & Expense	130,104.62	56051	Director's Lab & Expense	17,064.54
56100	Administration Labour & Exp	420,097.52	56100	Administration Labour & Exp	123,923.63
56101	Admin-Vehicle Exp Unit # 15	15,346.01	56101	Admin-Vehicle Exp Unit # 15	-
56102	Admin-Vehicle Exp Unit # 16	8,432.19	56102	Admin-Vehicle Exp Unit # 16	-
56103	Admin-Vehicle Exp Unit # 17	10,912.18	56103	Admin-Vehicle Exp Unit # 17	-
56104	Admin-Vehicle Exp Unit # 18	9,304.71	56104	Admin-Vehicle Exp Unit # 18	-
56150	Office Labour & Expenses	122,549.68	56150	Office Labour & Expenses	21,351.63
56151	Admin-Awards & Staff Functions	17,800.31	56151	Admin-Awards & Staff Functions	-
56152	Admin-Training, Seminars	1,359.55	56152	Admin-Training, Seminars	-
56300	OUTSIDE SERVICES EMPLOYED	-	56300	OUTSIDE SERVICES EMPLOYED	1,150.18
56350	Insurance-Admin Bldgs	6,979.08	56350	Insurance-Admin Bldgs	9,576.36
56351	Insurance-Substations	13,500.00	56351	Insurance-Substations	7,323.51
56352	Insurance-O/H Lines	14,000.00	56352	Insurance-O/H Lines	-
56353	Insurance-U/G Lines	14,000.00	56353	Insurance-U/G Lines	-
56354	Insurance-Transformers	14,000.00	56354	Insurance-Transformers	-
56550	Admin-Fees(Audit, MEA, etc)	534,377.00	56550	Admin-Fees(Audit, MEA, etc)	32,700.16
56700	Admin Bldg-Rental	180,000.00	56700	Admin Bldg-Rental	-
56750	Admin Bldg-Lab & Vehicle	1,220.15	56750	Admin Bldg-Lab & Vehicle	-
56751	Admin Bldg-Janitorial	21,004.66	56751	Admin Bldg-Janitorial	-

56752	Admin Bldg-Grounds Mtce	12,587.88	56752	Admin Bldg-Grounds Mtce	10,429.11
56753	Admin Bldg-Utilities	65,694.31	56753	Admin Bldg-Utilities	-
56754	Admin Bldg-Security	1,504.41	56754	Admin Bldg-Security	-
56755	Admin Bldg-HVAC Mtce	7,579.51	56755	Admin Bldg-HVAC Mtce	-
56756	Admin Bldg-Minor Upgrades	960.05	56756	Admin Bldg-Minor Upgrades	-
56759	Admin Bldg-Other	3,810.62	56759	Admin Bldg-Other	-
56760	Telephone SC/LD/Eq Rent	14,295.05	56760	Telephone SC/LD/Eq Rent	-
56761	Telephone-Cellular	3,541.98	56761	Telephone-Cellular	-
56762	Telephone-Other	3,318.73	56762	Telephone-Other	-
56770	Admin-Computer Maintenance	1,055.59	56770	Admin-Computer Maintenance	9,261.74
56771	Admin-Computer Minor Purchases	308.87	56771	Admin-Computer Minor Purchases	1,539.00
56772	Admin-Def'd Program Expense	0.00	56772	Admin-Def'd Program Expense	-
56773	Admin-Minor Software Purchases	5,940.00	56773	Admin-Minor Software Purchases	-
56774	Admin-Software Support	59,080.04	56774	Admin-Software Support	-
56775	Admin-Internet Service	4,730.40	56775	Admin-Internet Service	-
56779	Admin-Computer Other	1,971.00	56779	Admin-Computer Other	-
56780	Admin-Office Equipment Mtce	(3,671.07)	56780	Admin-Office Equipment Mtce	-
56781	Admin-OE Minor Purchases	382.25	56781	Admin-OE Minor Purchases	-
56782	Admin-Office Equip Leasing	13,506.06	56782	Admin-Office Equip Leasing	-
56789	Admin-Office Equip Other	0.00	56789	Admin-Office Equip Other	-
56790	Admin-Office Supplies	10,578.55	56790	Admin-Office Supplies	-
56791	Admin-Freight, Courier, Fax	6,189.01	56791	Admin-Freight, Courier, Fax	-
56792	Admin-Postage	5,000.00	56792	Admin-Postage	-
56793	Admin-Bank Charges	40,502.55	56793	Admin-Bank Charges	-
56799	Admin-Other	0.00	56799	Admin-Other	39,830.07
57050	Amortization Exp-General Plant	3,537,442.50	57050	Amortization Exp-General Plant	272,811.88
57051	Amortization Exp-Office Equip	15,158.92	57051	Amortization Exp-Office Equip	1,137.34
57052	Amortization Exp-Comp Hardware	49,132.50	57052	Amortization Exp-Comp Hardware	8,057.57
57053	Amortization Exp-Comp Software	159,037.77	57053	Amortization Exp-Comp Software	12,596.35

57054	Amortization Exp-Water Heaters	0.00	57054	Amortization Exp-Water Heaters	-
57055	Amortization Exp-Load Mgmnt	0.00	57055	Amortization Exp-Load Mgmnt	-
57056	Amortization Exp-Sentinel Lts	313.56	57056	Amortization Exp-Sentinel Lts	-
57057	Amortization Exp-Street Lts	0.00	57057	Amortization Exp-Street Lts	-
57059	Amortization Exp-Cont Cap	(501,921.68)	57059	Amortization Exp-Cont Cap	(11,879.27)
60050	Interest Exp-Debentures	0.00	60050	Interest Exp-Debentures	43,506.50
60350	Interest Exp-Customer Deposits	93,120.53	60350	Interest Exp-Customer Deposits	4,665.52
60359	Interest Exp-Other	1,685,000.00	60359	Interest Exp-Other	141,105.75
61050	Property Taxes-Substations	36,678.27	61050	Property Taxes-Substations	14,434.56
61051	Property Taxes-O/H Lines	898.13	61051	Property Taxes-O/H Lines	-
61052	Property Taxes-Buildings	65,520.34	61052	Property Taxes-Buildings	-
61053	Capital Tax	136,298.00	61053	Capital Tax	-
61100	Income Taxes	2,221,551.09	61100	Income Taxes	265,496.67
63050	Extraordinary Income	-	63050	Extraordinary Income	-
63100	Extraordinary Deductions	-	63100	Extraordinary Deductions	-
90190	Inclement Weather	-	90190	Inclement Weather	-
90200	Unproductive Labour	-	90200	Unproductive Labour	-
90210	Sfty Mtgs, Line Schl, Seminars	-	90210	Sfty Mtgs, Line Schl, Seminars	-
90211	Unproductive Labour	-	90211	Unproductive Labour	-
90220	Small Tool & Equip Purchases	-	90220	Small Tool & Equip Purchases	-
90230	Clothing	-	90230	Clothing	-
90240	Meals & Allowances	-	90240	Meals & Allowances	-
90250	Major Tool & Equip Depr	-	90250	Major Tool & Equip Depr	-
90260	Tool & Com Equip Mtce	-	90260	Tool & Com Equip Mtce	-
90270	Tool & Equip Demos & Training	-	90270	Tool & Equip Demos & Training	-
90280	Tool & Equip Rent & Lease	-	90280	Tool & Equip Rent & Lease	-
90290	Tool & Equip Exp Allocated	-	90290	Tool & Equip Exp Allocated	-
90410	Stores-Labour & Expense	-	90410	Stores-Labour & Expense	-

90420	Stores-Supplies & Expense	-	90420	Stores-Supplies & Expense	-
90430	Stores-Inventory Adjustment	-	90430	Stores-Inventory Adjustment	-
90440	Stores-Equipment Mtce	-	90440	Stores-Equipment Mtce	-
90450	Stores-Building Mtce	-	90450	Stores-Building Mtce	-
90460	Stores-Equipment Depreciation	-	90460	Stores-Equipment Depreciation	-
90470	Stores-Variance	-	90470	Stores-Variance	-
90480	Stores - Minor Material Purch	-	90480	Stores - Minor Material Purch	-
90490	Stores-Expense Allocated	-	90490	Stores-Expense Allocated	-
90510	S/C-Furn, Equip & Supplies	-	90510	S/C-Furn, Equip & Supplies	-
90520	S/C-Bldg Mtce	-	90520	S/C-Bldg Mtce	-
90530	S/C-Equipment Mtce	-	90530	S/C-Equipment Mtce	-
90540	S/C-Equipment Rent & Lease	-	90540	S/C-Equipment Rent & Lease	-
90550	S/C-Property Tax & Insurance	-	90550	S/C-Property Tax & Insurance	-
90590	S/C-Expense Allocated	-	90590	S/C-Expense Allocated	-
90610	P/R Burden-Retirees' Benefits	-	90610	P/R Burden-Retirees' Benefits	-
90710	Rolling Stock-Licences	-	90710	Rolling Stock-Licences	-
90720	Rolling Stock-Supplies & Exp	-	90720	Rolling Stock-Supplies & Exp	75.88
90730	Rolling Stock-Insurance	-	90730	Rolling Stock-Insurance	-
90740	Rolling Stock-Mtce, Gas & Oil	-	90740	Rolling Stock-Mtce, Gas & Oil	-
90741	Vehicle Exp Unit # 02	-	90741	Vehicle Exp Unit # 02	-
90742	Vehicle Exp Unit #10	-	90742	Vehicle Exp Unit #10	-
90750	Rolling Stock-Building Mtce	-	90750	Rolling Stock-Building Mtce	-
90760	Rolling Stock-Amortization	-	90760	Rolling Stock-Amortization	-
90770	Rolling Stock-Property Tax/Ins	-	90770	Rolling Stock-Property Tax/Ins	-
90790	Rolling Stock-Exp Allocated	-	90790	Rolling Stock-Exp Allocated	-
90810	Engineering-Lab, Vehicle & Exp	-	90810	Engineering-Lab, Vehicle & Exp	-
90820	Engineering-Supplies & Expense	-	90820	Engineering-Supplies & Expense	-
90830	Engineering-Contract Drafting	-	90830	Engineering-Contract Drafting	-

90840	Engineering-Computer Expenses	-	90840	Engineering-Computer Expenses	-
90890	Engineering-Expense Allocated	-	90890	Engineering-Expense Allocated	-
90900	Payroll Burdens	-	90900	Payroll Burdens	-
90910	P/R Burden - UIC	-	90910	P/R Burden - UIC	-
90920	P/R Burden - CPP	-	90920	P/R Burden - CPP	-
90930	P/R Burden - Emp Health Tax	-	90930	P/R Burden - Emp Health Tax	-
90940	P/P Burden-Pension & Insurance	-	90940	P/P Burden-Pension & Insurance	-
90941	Employee Future Benefits Exp	-	90941	Employee Future Benefits Exp	-
90950	PB-Sick Time	-	90950	PB-Sick Time	-
90951	PB-Vacation	-	90951	PB-Vacation	-
90952	PB-Stats/Bereave/Personal etc	-	90952	PB-Stats/Bereave/Personal etc	-
90960	P/R Burden - Workers' Comp	-	90960	P/R Burden - Workers' Comp	-
90970	P/R Burden - EHC,Dental,Vision	-	90970	P/R Burden - EHC,Dental,Vision	-
90971	P/R Burden - Future Benefits	-	90971	P/R Burden - Future Benefits	-
90980	P/R Burden - LT Disability Ins	-	90980	P/R Burden - LT Disability Ins	-
90990	Payroll Burden Allocated	-	90990	Payroll Burden Allocated	-
91000	Contributed Capital expense	-	91000	Contributed Capital expense	-
91010	Contributed Capital Expense	-	91010	Contributed Capital Expense	-
91200	Contributed Capital Amortized	-	91200	Contributed Capital Amortized	-
91210	Contributed Capital Amortized	-	91210	Contributed Capital Amortized	-
91220	Accumulated Contributed	-	91220	Accumulated Contributed	-
91300	Employee Benefit Liability	-	91300	Employee Benefit Liability	-
91310	Employee Benefit Expense	-	91310	Employee Benefit Expense	-
999991	PA O/H re-allocation clearing	-	999991	PA O/H re-allocation clearing	13.12
999999	Suspense (System Generated)	-	999999	Suspense (System Generated)	-

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NEWMARKET

Account #	ACC_NAME	YTD Actual
10050	Cash In Bank	3,934,076.93
10051	Payroll Bank Account	0.00
10052	U S Bank Account	1,306,203.34
10053	U S Exchange	0.00
10100	Permanent Cash Advances	0.00
10110	Temporary Cash Advances	0.00
10600	Term Deposits	0.00
10700	Current Investments	837,106.00
10701	Current Investments premium	0.00
11000	Customer Accounts Receivable	5,798,277.23
11100	Other Accounts Receivable	1,471,573.88
11101	AR-Municipal St Lt Maintenance	65,124.86
11102	AR-Billing Adjustments	1,347.57
11103	AR-Customer Time Payments	0.00
11104	AR-Recoverable Work	12,565.10
11105	AR- OMERS Overpayment	0.00
11106	AR-Accounts to Clo Agent	0.00
11107	Suspense	-20,830.00
11108	Consumer Deposits Suspense	0.00
11109	Accounts Receivable Suspense	0.00
11110	Letters of Credit Suspense	0.00
11111	AR-Municipal St Lt Capital	52,028.72
11112	AR-NHHI	126,817.00
11113	1443393 Ont Inc	0.00
11114	Retirements	0.00

TAY

Account #	ACC_NAME	YTD Actual
10050	Cash In Bank	1,285,606.19
10051	Payroll Bank Account	200.00
10052	U S Bank Account	0.00
10053	U S Exchange	0.00
10100	Permanent Cash Advances	0.00
10110	Temporary Cash Advances	0.00
10600	Term Deposits	0.00
10700	Current Investments	0.00
10701	Current Investments premium	0.00
11000	Customer Accounts Receivable	426,469.90
11100	Other Accounts Receivable	448,323.74
11101	AR-Municipal St Lt Maintenance	3,820.09
11102	AR-Billing Adjustments	0.00
11103	AR-Customer Time Payments	0.00
11104	AR-Recoverable Work	0.00
11105	AR- OMERS Overpayment	0.00
11106	AR-Accounts to Clo Agent	0.00
11107	Suspense	0.00
11108	Consumer Deposits Suspense	0.00
11109	Accounts Receivable Suspense	0.00
11110	Letters of Credit Suspense	0.00
11111	AR-Municipal St Lt Capital	0.00
11112	AR-NHHI	48,547.42
11113	1443393 Ont Inc	0.00
11114	Retirements	40,159.92

11200	Unbilled Revenue	7,444,032.86	11200	Unbilled Revenue	625,681.46
11300	Allowance for Doubtful Acct	-161,687.23	11300	Allowance for Doubtful Acct	-15,000.00
11700	Notes Receivable	0.00	11700	Notes Receivable	0.00
11800	Prepaid Expense	336,980.24	11800	Prepaid Expense	8,575.79
11801	Leased Vehicles	19,170.90	11801	Leased Vehicles	0.00
11802	Upper Canada Energy Alliance	-1,372.39	11802	Upper Canada Energy Alliance	0.00
11803	Prepaid Expense- ERA	0.00	11803	Prepaid Expense- ERA	0.00
11900	Other Current Assets	4,033.39	11900	Other Current Assets	0.00
13300	Inventory	889,719.51	13300	Inventory	105,762.52
13301	Inventory-Suspense	0.00	13301	Inventory-Suspense	0.00
13302	Inventory-Default	0.00	13302	Inventory-Default	0.00
13400	Inventory - Water St Retail	0.00	13400	Inventory - Water St Retail	0.00
14600	Long Term Rec-Billing Adj	0.00	14600	Long Term Rec-Billing Adj	0.00
14601	LT Rec - OMERS Overpayment	0.00	14601	LT Rec - OMERS Overpayment	0.00
14602	LT Rec - Cust Time Payment	0.00	14602	LT Rec - Cust Time Payment	0.00
15080	Other Regulatory Assets	0.00	15080	Other Regulatory Assets	45,024.85
15087	Other Regulatory Assets-CC	0.00	15087	Other Regulatory Assets-CC	4,489.57
15180	Retail Cost Variance - Retail	15,389.90	15180	Retail Cost Variance - Retail	-942.83
15187	Retail Cost Var -Retail CC	0.00	15187	Retail Cost Var -Retail CC	-65.42
15250	Misc Deferred Debits	0.00	15250	Deferred Charges	2,170.51
15251	Misc Deferred Debits - CC	0.00	15251	Misc Deferred Debits - CC	69.40
15252	Deferred Charges-Amortization	0.00	15252	Deferred Charges-Amortization	0.00
15253	UCEA Inc	0.00	15253	UCEA Inc	0.00
15254	Deferred Charges-Recovery	0.00	15254	Deferred Charges-Recovery	0.00
15480	Retail Cost Variance - STR	15,389.90	15480	Retail Cost Variance - STR	1,280.33
15487	Retail Cost Variance - STR-CC	0.00	15487	Retail Cost Variance - STR-CC	42.62
15500	Low Voltage Variance-Revenue	725.19	15500	Low Voltage Variance-Revenue	-84,905.67
15501	Low Voltage Variance-Costs	0.00	15501	Low Voltage Variance-Costs	89,948.70

15502	LV METERING CHARGE	0.00
15503	LV METERING MNTHLY CHARGE	0.00
15507	Low Voltage Variance-CC	0.00
15550	Smart Meter Capital Expenditur	0.00
15551	Smart Meter Cap/Rec Offset Var	0.00
15560	Smart Meter - OM&A	49,914.41
15551	Smart Meter - OM&A Revenue	0.00
15567	Smart Meter - OM&A CC	0.00
15620	Deferred PILS	0.00
15627	Deferred PILS - CC	0.00
15630	Deferred PILS - Contra	0.00
15637	Deferred PILS - Contra-CC	0.00
15650	Conserve & Demand Revenue	-1,267,000.00
15651	Gateway Project	0.00
15652	Residential	351,441.61
15653	Affordable/Social Housing	368,316.25
15654	Small Business	0.00
15655	Business/Commerical/Industrial	79,886.43
15656	Education Program	228,607.00
15657	Other Programs/Discretionary	96,973.07
15658	Distributions System studies	0.00
15659	Program Develop & Monitoring	141,776.08
15660	C&DM Recovered From Customers	0.00
15700	Transition Costs	94,365.70
15701	Transition Costs - Recovery	0.00
15707	Transition Costs - CC	0.00
15710	Pre Market Energy	0.00
15711	Pre Market Energy-Residential	0.00

15502	LV METERING CHARGE	0.00
15503	LV METERING MNTHLY CHARGE	0.00
15507	Low Voltage Variance-CC	293.83
15550	Smart Meter Capital Expenditur	0.00
15551	Smart Meter Cap/Rec Offset Var	-74,282.24
15560	Smart Meter - OM&A	0.00
15551	Smart Meter - OM&A Revenue	0.00
15567	Smart Meter - OM&A CC	0.00
15620	Deferred PILS	123,821.40
15627	Deferred PILS - CC	6,192.48
15630	Deferred PILS - Contra	-123,821.40
15637	Deferred PILS - Contra-CC	-6,192.48
15650	Conserve & Demand Revenue	0.00
15651	Gateway Project	0.00
15652	Residential	-112.89
15653	Affordable/Social Housing	0.00
15654	Small Business	0.00
15655	Business/Commerical/Industrial	0.00
15656	Education Program	11,369.13
15657	Other Programs/Discretionary	30,917.55
15658	Distributions System studies	3,874.53
15659	Program Develop & Monitoring	3,612.98
15660	C&DM Recovered From Customers	-41,808.83
15700	Transition Costs	0.00
15701	Transition Costs - Recovery	0.00
15707	Transition Costs - CC	0.00
15710	Pre Market Energy	0.00
15711	Pre Market Energy-Residential	0.00

15712	Pre Market Energy-GS LT 50	0.00
15713	Pre Market Energy-GS GT 50 kW	0.00
15714	Pre Market Energy-GS GT 50 kWh	0.00
15715	Pre Market Energy-Street Light	0.00
15716	Pre Market Energy-Sentinel Lts	0.00
15718	Pre Market - Variance Recovery	0.00
15800	RSVA-Whlsle Market Serv Rev	-17,126,375.32
15801	RSVA-Whlsle Market Serv Chg	15,460,694.40
15802	RSVA-WMS Fixed Chg Settltment	1,000,639.74
15807	RSVA-WMS CC	0.00
15808	RSVA-WMS - Recovery	0.00
15809	RSVA-WMS Unbilled	-477,630.04
15820	RSVA-One Time Charges-Revenue	0.00
15821	RSVA-One Time Charges-Charges	106,567.29
15827	RSVA-One Time -CC	0.00
15840	RSVA-Trans Network Revenue	-14,532,008.06
15841	RSVA-Trans Network Charges	15,953,397.74
15842	RSVA-Trans Meter Credit	-57,950.00
15847	RSVA-Trans Network CC	0.00
15848	RSVA-Trans Network Recovery	0.00
15849	RSVA-Trans Network Unbilled	0.00
15860	RSVA-Trans Connection Revenue	-12,729,267.60
15861	RSVA-Trans Connection Charges	13,242,054.04
15867	RSVA-Trans Connection CC	0.00
15868	RSVA-Trans Connection Recovery	0.00
15869	RSVA-Trans Unbilled	-769,714.43
15880	RSVA-Power Pd By Customers	-116,945,760.52
15881	RSVA-Power purchase IESO	224,189,262.26

15712	Pre Market Energy-GS LT 50	0.00
15713	Pre Market Energy-GS GT 50 kW	0.00
15714	Pre Market Energy-GS GT 50 kWh	0.00
15715	Pre Market Energy-Street Light	0.00
15716	Pre Market Energy-Sentinel Lts	0.00
15718	Pre Market - Variance Recovery	0.00
15800	RSVA-Whlsle Market Serv Rev	-835,696.83
15801	RSVA-Whlsle Market Serv Chg	862,154.17
15802	RSVA-WMS Fixed Chg Settltment	0.00
15807	RSVA-WMS CC	1,812.54
15808	RSVA-WMS - Recovery	0.00
15809	RSVA-WMS Unbilled	-39,518.02
15820	RSVA-One Time Charges-Revenue	0.00
15821	RSVA-One Time Charges-Charges	-2,427.88
15827	RSVA-One Time -CC	-216.00
15840	RSVA-Trans Network Revenue	-714,051.06
15841	RSVA-Trans Network Charges	700,146.11
15842	RSVA-Trans Meter Credit	0.00
15847	RSVA-Trans Network CC	-1,878.92
15848	RSVA-Trans Network Recovery	0.00
15849	RSVA-Trans Network Unbilled	-33,132.89
15860	RSVA-Trans Connection Revenue	-631,059.74
15861	RSVA-Trans Connection Charges	405,118.76
15867	RSVA-Trans Connection CC	-52,635.16
15868	RSVA-Trans Connection Recovery	0.00
15869	RSVA-Trans Unbilled	-29,178.70
15880	RSVA-Power Pd By Customers	-353,384.43
15881	RSVA-Power purchase IESO	7,580,079.85

15882	Spot Price Pd By Customers	-102,105,339.10	15882	Spot Price Pd By Customers	-1,823,014.43
15883	Fixed Price Pd By Customers	-103,148,083.22	15883	Fixed Price Pd By Customers	-6,467,871.80
15884	Fixed Price Variance Account	114,789,645.79	15884	Fixed Price Variance Account	1,296,917.95
15885	Fixed Price IMO Settlement	-9,205,148.34	15885	Fixed Price IMO Settlement	0.00
15886	Fixed Price Time of Use Rates	-191,409.70	15886	Fixed Price Time of Use Rates	-26,726.25
15887	RSVA - Power - CC	0.00	15887	RSVA - Power - CC	18,715.51
15888	RSVA - Energy Recovery	0.01	15888	RSVA - Energy Recovery	0.00
15889	RSVA-Power Unbilled	-4,608,456.61	15889	RSVA-Power Unbilled	-322,018.94
15890	Pre-Market & RSVA Clearing	0.00	15890	Pre-Market & RSVA Clearing	0.00
15900	Approved Reg Assets	3,446,593.08	15900	Approved Reg Assets	716,661.00
15901	Approved Reg Assets - Recovery	-3,618,648.55	15901	Approved Reg Assets - Recovery	-651,161.73
15907	Approved Reg Assets -CC	0.00	15907	Approved Reg Assets -CC	12,852.55
15950	Approved Deferral Balance-2008	0.00	15950	Approved Deferral Balance-2008	0.00
15951	APPROVED DEFERRALRECOVERY2008	0.00	15951	APPROVED DEFERRALRECOVERY2008	0.00
15952	APPROVED SM RECOVERY-2008	0.00	15952	APPROVED SM RECOVERY-2008	0.00
15956	Approved CC to be Recovered-08	0.00	15956	Approved CC to be Recovered-08	0.00
15957	Approved Deferral CC-2008	0.00	15957	Approved Deferral CC-2008	0.00
15959	Unbilled Deferral & Smart M.	0.00	15959	Unbilled Deferral & Smart M.	0.00
15990	Regulated Price Plan Settlemen	-2,451,479.69	15990	Regulated Price Plan Settlemen	0.00
15991	Reg Price Plan retailer settl	-428,572.46	15991	Reg Price Plan retailer settl	183,225.69
15993	Global Adj - CC	0.00	15993	Global Adj - CC	-636.84
15994	Global Adj Payabe re lRPP	0.00	15994	Global Adj Payabe re lRPP	0.00
15995	Global adjustment	-175,401.27	15995	Global adjustment	48,601.66
15996	Global Adj Settlement Amount	356,797.17	15996	Global Adj Settlement Amount	0.00
15997	RPP Adj Settlement Amount	-76,054.31	15997	RPP Adj Settlement Amount	-48,036.42
16060	Organization Costs	0.00	16060	Organization Costs	27,610.98
18050	Distribution-Land	2,512,189.95	18050	Distribution-Land	58,066.87
18060	Dist - Land Rights	0.00	18060	Distribution-Land Rights	241,736.72

18200	Dist Stn-Rec Complex	77,383.00	18200	Dist Stn-Rec Complex	0.00
18201	Dist Stn-Legge	636,165.66	18201	Dist Stn-Legge	0.00
18202	Dist Stn-Thompson	987,228.74	18202	Dist Stn-Thompson	0.00
18203	Dist Stn-Broughton/Simmons	1,061,522.23	18203	Dist Stn-Broughton/Simmons	0.00
18204	Dist Stn-Gilbert	1,134,679.71	18204	Dist Stn-Gilbert	0.00
18205	Dist Stn-Andrews	1,113,931.67	18205	Dist Stn-Andrews	0.00
18206	Dist Stn-Leadbeater	688,398.98	18206	Dist Stn-Leadbeater	0.00
18207	Dist Stn-Cook	473,028.86	18207	Dist Stn-Cook	0.00
18208	Dist Stn-Twinney	1,262,175.57	18208	Dist Stn-Twinney	0.00
18209	Dist Stn-S/E Quadrant	523,899.57	18209	Dist Stn-S/E Quadrant	0.00
18210	Dist Stn-Miscellaneous	15,244.78	18210	Dist Stn-Miscellaneous	0.00
18211	Dist Stn Port McNicholl	0.00	18211	Dist Stn Port McNicholl	108,852.49
18212	Dist Stn Victoria Harbour	0.00	18212	Dist Stn Victoria Harbour	285,843.55
18213	Dist Stn Waubaushene	0.00	18213	Dist Stn Waubaushene	98,161.72
18214	Port McNicholl MS 2	0.00	18214	Port McNicholl MS 2	0.00
18300	Dist Lines O/H Poles	11,411,389.98	18300	Dist Lines O/H Poles	1,625,620.16
18301	Inventory Holding - O/H Poles	0.00	18301	Inventory Holding - O/H Poles	0.00
18350	Dist Lines O/H Conductor	14,200,846.71	18350	Dist Lines O/H Conductor	1,432,899.35
18351	Invent. Holding- O/H Conductor	0.00	18351	Invent. Holding- O/H Conductor	0.00
18400	Dist Lines U/G Conduit	7,089,918.23	18400	Dist Lines U/G Conduit	51,660.70
18401	Inventory Holding-U/G Conduit	0.00	18401	Inventory Holding-U/G Conduit	0.00
18450	Dist Lines U/G Conductor	22,497,824.12	18450	Dist Lines U/G Conductor	280,778.29
18451	Invent. Holding-U/G Conductor	0.00	18451	Invent. Holding-U/G Conductor	0.00
18500	Distribution Transformers	14,183,937.18	18500	Distribution Transformers	1,069,055.09
18501	Invent. Holding-Transformers	0.00	18501	Invent. Holding-Transformers	0.00
18550	Services	4,197,441.21	18550	Services	1,256,216.59
18551	44 KV CAPITAL STUDY	6,530.26	18551	44 KV CAPITAL STUDY	0.00
18552	13.8 KV CAPITAL STUDY	2,517.15	18552	13.8 KV CAPITAL STUDY	0.00

18600	Distribution Meters	3,898,600.06	18600	Distribution Meters	29,217.00
18610	Smart Meters	3,590,943.84	18610	Smart Meters	430,958.77
18650	Wholesale Meters	919,634.49	18650	Wholesale Meters	0.00
18750	Distribution Street Lights	0.00	18750	Distribution Street Lights	0.00
18990	Capital Asset Management	0.00	18990	Capital Asset Management	0.00
189999	Capital Holding Account	0.00	189999	Capital Holding Account	0.00
19050	General Plant - Land	89.70	19050	General Plant - Land	0.00
19080	Buildings-Eagle Street	0.00	19080	Buildings-Eagle Street	279,019.69
19081	Leasehold Imp-Steven Court	419,235.50	19081	Leasehold Imp-Steven Court	0.00
19082	Buildings-Water Street	0.00	19082	Buildings-Water Street	0.00
19083	Buildings-Other	0.00	19083	Buildings-Other	0.00
19150	Office Equipment	275,234.59	19150	Office Equipment	50,286.61
19200	Computer Hardware	652,492.96	19200	Computer Hardware	70,631.54
19250	Computer Software	1,138,803.98	19250	Computer Software	259,743.30
19300	Transportation Equipment	2,942,171.74	19300	Transportation Equipment	335,232.23
19350	Stores Equipment	142,098.64	19350	Stores Equipment	6,384.82
19400	Tools, Shop & Garage Equipment	419,726.09	19400	Tools, Shop & Garage Equipment	56,538.62
19450	Measurement & Testing Equip	102,535.07	19450	Measurement & Testing Equip	0.00
19650	Water Heater Rental units	0.00	19650	Water Heater Rental units	0.00
19800	System Supervisory Equipment	728,163.51	19800	System Supervisory Equipment	0.00
19810	System Optimization Study	10,871.57	19810	System Optimization Study	0.00
19850	Sentinel Light Rental Units	13,085.27	19850	Sentinel Light Rental Units	9,966.47
19900	Amalco Capital	0.00	19900	Amalco Capital	0.00
19950	Cont Cap to be Amortized	-13,902,241.83	19950	Cont Cap to be Amortized	-364,725.55
199999	Fixed Assets Suspense	0.00	199999	Fixed Assets Suspense	0.00
20550	Construction In Progress	0.00	20550	Construction In Progress	0.00
21050	Accum Dep-Current Provision	0.00	21050	Accum Dep-Current Provision	0.00
21051	Accum Amor-Organization Costs	0.00	21051	Accum Amor-Organization Costs	-16,566.00

21052	Accum Amor-Buildings Other	0.00	21052	Accum Amor-Buildings Other	-78,186.30
21053	Accum Amor-Stations	-3,980,155.54	21053	Accum Amor-Stations	-270,713.64
21054	Accum Amor-O/H Lines	-12,138,104.14	21054	Accum Amor-O/H Lines	-1,995,270.83
21055	Accum Amor-Land Rights	0.00	21055	Accum Amor-Land Rights	-107,857.80
21056	Accum Amor-U/G Lines	-15,401,454.69	21056	Accum Amor-U/G Lines	-823,317.01
21057	Accum Amor-Transformers	-6,757,228.29	21057	Accum Amor-Transformers	-604,072.81
21058	Accum Amor-Meters	-2,274,498.17	21058	Accum Amor-Meters	-41,820.19
21059	Accum Amor-Street Lights	0.00	21059	Accum Amor-Street Lights	0.00
21060	Accum Amor-Office Equipment	-161,790.70	21060	Accum Amor-Office Equipment	-46,846.46
21061	Accum Amor-Computer Equipment	-471,169.00	21061	Accum Amor-Computer Equipment	-49,913.39
21062	Accum Amor-Computer Software	-680,282.37	21062	Accum Amor-Computer Software	-133,949.57
21063	Accum Amor-Stores Equipment	-94,356.86	21063	Accum Amor-Stores Equipment	-6,332.20
21064	Accum Amor-Transportation Equi	-2,085,392.58	21064	Accum Amor-Transportation Equi	-303,641.95
21065	Accum Amor-Tools	-349,990.36	21065	Accum Amor-Tools	-49,004.79
21066	Accum Amor-Water Heaters	0.00	21066	Accum Amor-Water Heaters	0.00
21067	Accum Amor-Leasehold	-326,409.20	21067	Accum Amor-Leasehold	0.00
21068	Accum Amor-System Supervisory	-479,178.94	21068	Accum Amor-System Supervisory	0.00
21069	Accum Amor-Sentinel Lights	-12,847.77	21069	Accum Amor-Sentinel Lights	-9,966.47
21070	Accum Amor-Street Lights	0.00	21070	Accum Amor-Street Lights	0.00
21090	Accum Amor-Cont Cap	2,547,269.64	21090	Accum Amor-Cont Cap	33,091.46
22050	Accounts Payable	-1,248,418.69	22050	Accounts Payable	-1,638,925.13
22051	A/P-Town Water Billing	-1,249,434.96	22051	A/P-Town Water Billing	0.00
22052	A/P-Power Bill	-4,378,931.14	22052	A/P-Power Bill	0.00
22053	A/P-Income Tax	409,109.00	22053	A/P-Income Tax	54,999.76
22054	Miscellaneous Accruals	-354,807.72	22054	Miscellaneous Accruals	-140,225.93
22055	A/P-MPMA Rebate	-67,431.05	22055	A/P-MPMA Rebate	1,038.50
22056	A/P-Phase 2 Rebate	0.00	22056	A/P-Phase 2 Rebate	0.00
22057	A/P-$75 Rebate	0.00	22057	A/P-$75 Rebate	0.00

22058	Accounts Payable-Default	0.00
22059	A/P-Town Other	-2,939,999.88
22060	Invoice Settlement-Direct	0.00
22061	BRC - Toronto Hydro	0.00
22062	BRC - OPG	0.00
22063	BRC - Ontario Hydro	0.00
22064	BRC - First Source	0.00
22065	BRC - Ontario Electric Savings	0.00
22066	BRC - Coral Energy	0.00
22067	BRC - Canadian Choice Energy	0.00
22068	BRC - Constellation New Energy	0.00
22069	BRC - Universal Energy	0.00
22070	BRC - ECNG	0.00
22071	BRC -Canadian Hydro	0.00
22072	BRC - Bullfrog Power	0.00
22073	BRC - SEMINC	0.00
22074	BRC - Superior Energy	0.00
22075	BRC - Wholesale Energy	0.00
22076	BRC - Planet Energy Ontario Co	0.00
22077	BRC - AG ENERGY CO-OP LTD	0.00
22078	BRC - National Energy Corp.	0.00
22080	Customer Credit Balances	-739,903.65
22100	Customer Deposits-Current	-300,000.00
22200	Unused Vacation Pay Accrual	-80,129.39
22201	Payroll Clearing	-134,793.49
222011	Interco due to & due from	-71,893.56
22202	Subdivider Lot Levies-Current	-52,586.00
22250	Other Current Liabilities	0.00

22058	Accounts Payable-Default	13,000.00
22059	A/P-Town Other	-390,000.00
22060	Invoice Settlement-Direct	37.03
22061	BRC - Toronto Hydro	0.00
22062	BRC - OPG	0.00
22063	BRC - Ontario Hydro	0.00
22064	BRC - First Source	-37.03
22065	BRC - Ontario Electric Savings	11,468.76
22066	BRC - Coral Energy	0.00
22067	BRC - Canadian Choice Energy	0.00
22068	BRC - Constellation New Energy	0.00
22069	BRC - Universal Energy	0.36
22070	BRC - ECNG	0.00
22071	BRC -Canadian Hydro	0.00
22072	BRC - Bullfrog Power	0.00
22073	BRC - SEMINC	0.00
22074	BRC - Superior Energy	0.00
22075	BRC - Wholesale Energy	0.00
22076	BRC - Planet Energy Ontario Co	0.00
22077	BRC - AG ENERGY CO-OP LTD	0.00
22078	BRC - National Energy Corp.	0.00
22080	Customer Credit Balances	-99,425.00
22100	Customer Deposits-Current	0.00
22200	Unused Vacation Pay Accrual	-8,371.61
22201	Payroll Clearing	-20,929.59
222011	Interco due to & due from	71,893.56
22202	Subdivider Lot Levies-Current	0.00
22250	Other Current Liabilities	-184,111.93

22251	Notes and Loans Payable	0.00
22500	Debt Retirement Charges	0.00
22560	AP - IMO	0.00
22600	Current Portion Long Term Debt	0.00
22601	Current Portion Other Debt	0.00
22640	OPA - Refrigerator Roundup	0.00
22641	OPA - Summer Savings	0.00
22642	OPA - Peaksaver	0.00
226421	OPA - ERIP	-7,401.07
226422	OPA-Direct Installs	0.00
226423	OPA-Comm Initiative Fund	0.00
226424	OPA - MEER	0.00
22643	Thermostats - Barrie	0.00
22644	Thermostats - Innisfil	0.00
22645	Thermostats -Essex	0.00
22646	Thermostats -Enwin	0.00
22647	Thermostats -Erie Thames	0.00
22648	Thermostats -St Thomas	0.00
22649	Thermostats -Clinton	0.00
22650	Thermostats -West Perth	0.00
22680	Accrued Interest-L T Debt	0.00
22681	Accrued Interest-Cust Deps	-1,783.58
22901	GST - ITC 100%	2,410.04
22902	GST - ITC 57.14% St Lts	0.00
22903	GST - ITC 50%	0.00
22904	GST - Collected	-6,869.02
22905	GST - Remittance	0.00
22909	PST Payable	-7,618.72

22251	Notes and Loans Payable	0.00
22500	Debt Retirement Charges	-13,450.83
22560	AP - IMO	0.00
22600	Current Portion Long Term Debt	0.00
22601	Current Portion Other Debt	0.00
22640	OPA - Refrigerator Roundup	4,012.00
22641	OPA - Summer Savings	14,980.13
22642	OPA - Peaksaver	1,333.57
226421	OPA - ERIP	0.00
226422	OPA-Direct Installs	0.00
226423	OPA-Comm Initiative Fund	0.00
226424	OPA - MEER	0.00
22643	Thermostats - Barrie	0.00
22644	Thermostats - Innisfil	0.00
22645	Thermostats -Essex	0.00
22646	Thermostats -Enwin	0.00
22647	Thermostats -Erie Thames	0.00
22648	Thermostats -St Thomas	0.00
22649	Thermostats -Clinton	0.00
22650	Thermostats -West Perth	0.00
22680	Accrued Interest-L T Debt	0.00
22681	Accrued Interest-Cust Deps	-1,803.34
22901	GST - ITC 100%	-251,770.01
22902	GST - ITC 57.14% St Lts	0.00
22903	GST - ITC 50%	-6.42
22904	GST - Collected	200,289.77
22905	GST - Remittance	0.00
22909	PST Payable	-9.04

22921	Income Tax Payable	0.00
22922	CPP Payable	0.00
22923	Employment Insurance Payable	0.00
22924	OMERS Payable	0.00
22925	EHT Payable	0.00
22926	W.S.I.B. Payable	0.00
22927	Life Insurance Payable	0.00
22928	Garnishee Payable	0.00
22929	Union Dues	0.00
229291	RRSP Payable	0.00
23060	Employee Future Benefits	-727,243.00
23200	Other Non-Current Liabilities	0.00
23201	Deferred Credits	-94,996.00
23300	Subdividers Lot Levies	0.00
23301	Lot Levies-Single Units	0.00
23350	Customer Deposits	-2,688,325.55
23351	Construction Deposits	-1,298,646.90
23352	Retailer Deposits	-51,786.48
23353	Consumer Deposit Suspense	-37,385.60
24050	Other Regulatory Liabilities	0.00
25000	Long Term Debt	0.00
25200	Long Term Debt - Town	-22,000,000.00
30220	Lot Levies Transf'd to Equity	-201,720.00
30300	Contributed Capital-Equity	-33,468,574.15
30301	Contributed Capital-St Lts	0.00
30450	Accumulated Net Income	835,480.94
30451	Dividends Paid	3,788,000.00
30490	Dividends Declared	4,410,000.00

22921	Income Tax Payable	0.00
22922	CPP Payable	0.00
22923	Employment Insurance Payable	0.00
22924	OMERS Payable	0.00
22925	EHT Payable	0.00
22926	W.S.I.B. Payable	0.00
22927	Life Insurance Payable	0.00
22928	Garnishee Payable	0.00
22929	Union Dues	0.00
229291	RRSP Payable	-4,928.11
23060	Employee Future Benefits	-15,111.00
23200	Other Non-Current Liabilities	0.00
23201	Deferred Credits	0.00
23300	Subdividers Lot Levies	0.00
23301	Lot Levies-Single Units	0.00
23350	Customer Deposits	-154,826.91
23351	Construction Deposits	0.00
23352	Retailer Deposits	0.00
23353	Consumer Deposit Suspense	0.00
24050	Other Regulatory Liabilities	-4,012.00
25000	Long Term Debt	-436,000.00
25200	Long Term Debt - Town	-1,742,821.00
30220	Lot Levies Transf'd to Equity	0.00
30300	Contributed Capital-Equity	-1,742,821.00
30301	Contributed Capital-St Lts	0.00
30450	Accumulated Net Income	-28,225.00
30451	Dividends Paid	565,000.00
30490	Dividends Declared	0.00

40060	Energy-Residential	-1,165.58	40060	Energy-Residential	0.00
40061	Residential-Dist Customer Chg	-3,807,759.35	40061	Residential-Dist Customer Chg	-705,487.71
40062	Residential-Dist kWh	-3,633,500.61	40062	Residential-Dist kWh	-322,876.53
40063	Residential-Energy kWh	0.00	40063	Residential-Energy kWh	0.00
40064	Residential-Retro Adjustment	0.00	40064	Residential-Retro Adjustment	6,033.77
40068	Energy-Res-PILS Trans Recovery	371,604.22	40068	Energy-Res-PILS Trans Recovery	0.00
40250	Energy-Street Lights	-950.43	40250	Energy-Street Lights	0.00
40251	Energy-Sentinel Lights	0.00	40251	Energy-Sentinel Lights	0.00
40252	Street Light-Dist kW Charge	-25,141.88	40252	Street Light-Dist kW Charge	-3,473.77
40253	Street Light-Energy kW Charge	0.00	40253	Street Light-Energy kW Charge	-3,587.66
40254	Street Light-Retro Adj	0.00	40254	Street Light-Retro Adj	0.00
40255	Street Light-Dist Fixed Chg	-25,854.93	40255	Street Light-Dist Fixed Chg	-982.56
40258	St Light-PIL Trans Recovery	3,822.72	40258	St Light-PIL Trans Recovery	0.00
40302	Sentinel Light Distribution kW	-3,079.81	40302	Sentinel Light Distribution kW	-132.64
40303	Sentinel Light Energy kW	0.00	40303	Sentinel Light Energy kW	-97.89
40305	Sentinel Light Service Charge	-8,562.54	40305	Sentinel Light Service Charge	-25.66
40308	Sent Lt PILS Trans Recovery	370.41	40308	Sent Lt PILS Trans Recovery	0.00
40350	GT 50 - Dist Electric Meter Ad	0.00	40350	GT 50 - Dist Electric Meter Ad	-1,077.75
40351	GS LT 50-Dist Cust Chg	-666,006.50	40351	GS LT 50-Dist Cust Chg	-60,793.90
40352	GS LT 50-Dist kWh Charge	-1,724,797.67	40352	GS LT 50-Dist kWh Charge	-47,695.26
40353	GS LT 50-Energy kWh Charge	0.00	40353	GS LT 50-Energy kWh Charge	0.00
40354	GS LT 50-PIL Trans Recovery	139,435.36	40354	GS LT 50-PIL Trans Recovery	0.00
40355	GS GT 50-Dist Cust Charge	-1,681,806.43	40355	GS GT 50-Dist Cust Charge	-30,073.87
40356	GS GT 50-Dist kW Charge	-3,123,537.75	40356	GS GT 50-Dist kW Charge	-203,372.26
40357	GS GT 50-Energy kW Charge	0.00	40357	GS GT 50-Energy kW Charge	0.00
40358	GS GT 50-PIL Trans Recovery	560,254.15	40358	GS GT 50-PIL Trans Recovery	0.00
40359	GS GT 50-Retro Adj	0.00	40359	GS GT 50-Retro Adj	1,113.15
40360	C&DM Recovered From Customers	0.00	40360	C&DM Recovered From Customers	0.00

40500	Energy-Adjustments	-27,855.77
40550	Smart Meter Revenue Rec'd	0.00
40551	WAP/R - Direct	0.00
40552	WAP/GS - Direct	0.00
40553	WAP/R - THESI	0.00
40554	WAP/GS - THESI	0.00
40555	WAP/R - OPG	0.00
40556	WAP/GS - OPG	0.00
40557	WAP/R - OHE	0.00
40558	WAP/GS - OHE	0.00
40559	WAP/R - First Source	0.00
40560	WAP/GS - First Source	0.00
40561	WAP/R - Coral Energy	0.00
40562	WAP/GS - Coral Energy	0.00
40563	WAP/R - OESC	0.00
40564	WAP/GS - OESC	0.00
40565	WAP/R - Cdn Choice	0.00
40566	WAP/GS - Cdn Choice	0.00
40620	Whlsl Mrkt Services Billed	0.00
40640	Whlsl Mrkt Srvcs Blld 1 time	0.00
40660	Retail Transmission Service	0.00
40680	Retail Transmission Connection	0.00
40800	SSS Administration Charge	-91,208.89
40801	Distribution Wheeling Service	0.00
40802	Recver Reg Assets prev W/O	-465,462.67
40820	Retail Service Revenues	-40,620.60
40840	STR Revenues	-1,512.75
42103	Revenue-Pole Rentals	-63,091.06

40500	Energy-Adjustments	-25,454.96
40550	Smart Meter Revenue Rec'd	57,256.74
40551	WAP/R - Direct	0.00
40552	WAP/GS - Direct	0.00
40553	WAP/R - THESI	0.00
40554	WAP/GS - THESI	0.00
40555	WAP/R - OPG	0.00
40556	WAP/GS - OPG	0.00
40557	WAP/R - OHE	0.00
40558	WAP/GS - OHE	0.00
40559	WAP/R - First Source	0.00
40560	WAP/GS - First Source	0.00
40561	WAP/R - Coral Energy	0.00
40562	WAP/GS - Coral Energy	0.00
40563	WAP/R - OESC	0.00
40564	WAP/GS - OESC	0.00
40565	WAP/R - Cdn Choice	0.00
40566	WAP/GS - Cdn Choice	0.00
40620	Whlsl Mrkt Services Billed	0.00
40640	Whlsl Mrkt Srvcs Blld 1 time	0.00
40660	Retail Transmission Service	0.00
40680	Retail Transmission Connection	0.00
40800	SSS Administration Charge	-12,070.63
40801	Distribution Wheeling Service	0.00
40802	Recver Reg Assets prev W/O	0.00
40820	Retail Service Revenues	-416.10
40840	STR Revenues	-7,427.70
42103	Revenue-Pole Rentals	-51,431.55

42250	Revenue-Late Payment Charges	-182,369.86
42350	Revenue-St LT Non-Energy	0.00
42351	Account Setup	-45,387.50
42352	Revenue-Reconnection Charges	-24,658.52
42353	Revenue-Collection Charges	-135,133.50
42354	Change of Occupancy-Final Bill	-41,362.50
43102	Revenue-Sentinel Lt Rentals	-14,078.40
43250	Revenue-Sale of Scrap Metals	-17,115.18
43251	Water St-Mark Up on Sales	0.00
43550	Gain on Sale of Assets	-8,372.24
43600	Loss on Sale of Assets	987,056.00
43850	Non-Utility Rental Income	0.00
43851	Water Heater Rental Income	0.00
43900	Revenue-Miscellaneous	-22,280.65
43901	Revenue-Profit on Mat & Serv	-13,651.38
43902	Revenue-Arrears Certificates	-2,068.61
43903	Revenue-Power Bill Aggregation	0.00
43904	Costs re By-passed Meters	0.00
43905	Revenue re By-passed Meters	0.00
44050	Interest Earned	-413,270.59
44051	CC on Reg Assets	0.00
47050	Pre Market & RSVA Clearing	0.00
47051	Transition Cost Write Off	0.00
47080	Power Purchased - WMS	0.00
47100	Power Purchased-Adjustments	0.00
47120	Power Purchased - On Time	0.00
47140	Power Purchased - Network	0.00
47160	Power Purchased - Connection	0.00

42250	Revenue-Late Payment Charges	-8,296.22
42350	Revenue-St LT Non-Energy	0.00
42351	Account Setup	0.00
42352	Revenue-Reconnection Charges	-15,821.20
42353	Revenue-Collection Charges	-4,834.95
42354	Change of Occupancy-Final Bill	0.00
43102	Revenue-Sentinel Lt Rentals	-1,966.80
43250	Revenue-Sale of Scrap Metals	0.00
43251	Water St-Mark Up on Sales	0.00
43550	Gain on Sale of Assets	0.00
43600	Loss on Sale of Assets	126,025.87
43850	Non-Utility Rental Income	0.00
43851	Water Heater Rental Income	0.00
43900	Revenue-Miscellaneous	-20,405.39
43901	Revenue-Profit on Mat & Serv	-475.00
43902	Revenue-Arrears Certificates	0.00
43903	Revenue-Power Bill Aggregation	0.00
43904	Costs re By-passed Meters	0.00
43905	Revenue re By-passed Meters	0.00
44050	Interest Earned	-53,688.50
44051	CC on Reg Assets	-1,131.57
47050	Pre Market & RSVA Clearing	0.00
47051	Transition Cost Write Off	0.00
47080	Power Purchased - WMS	0.00
47100	Power Purchased-Adjustments	0.00
47120	Power Purchased - On Time	0.00
47140	Power Purchased - Network	0.00
47160	Power Purchased - Connection	0.00

47250	Competition Transition Charges	0.00
50050	Operation Supervision	0.00
50160	Substn Op'n-Labour	13,451.62
50161	Substn Op'n-Inspect & Tes	25,512.69
50170	Substn Op'n-Supplies & Expense	153.81
50200	O/H Line Operation-Labour	143,182.75
50250	O/H Line Op'n-Supplies & Exp	2,318.67
50350	O/H Dist Transformer Operation	12,167.38
50400	U/G Line Op'n-Labour	53,713.67
50401	U/G Line Op'n-Stakeouts	181,184.75
50450	U/G Line Op'n-Supplies & Exp	18,515.65
50451	U/G Line Op'n-Stakeouts	0.00
50550	U/G Dist Transformer Operation	49,377.06
50551	Dist Trans - Inspect & Test	0.00
50650	Dist Meters-Reverification	155,796.68
50651	Dist Meters-Dispute Test	178.06
50652	Dist Meters-Seal Extension	862.57
50653	Dist Meters-Technical Training	0.00
50654	Dist Meters-Computer Costs	0.00
50655	Dist Meters-Other	37.79
50701	Customer Premises-Stakeouts	40,154.37
50702	Customer Fire & No Power Calls	37,825.50
50703	Customer Station Maintenance	13,591.19
50800	Engineering & Operations	0.00
50801	Engineering & Ops Training	18,703.33
50950	O/H Lines Op-Rentals Paid	10,541.54
51140	Substation Maintenance	3,773.40
51141	Substn Mtce-Land & Building	39,079.70

47250	Competition Transition Charges	0.00
50050	Operation Supervision	0.00
50160	Substn Op'n-Labour	870.54
50161	Substn Op'n-Inspect & Tes	1,601.77
50170	Substn Op'n-Supplies & Expense	0.00
50200	O/H Line Operation-Labour	12,082.14
50250	O/H Line Op'n-Supplies & Exp	1,930.87
50350	O/H Dist Transformer Operation	894.78
50400	U/G Line Op'n-Labour	0.00
50401	U/G Line Op'n-Stakeouts	0.00
50450	U/G Line Op'n-Supplies & Exp	67.28
50451	U/G Line Op'n-Stakeouts	0.00
50550	U/G Dist Transformer Operation	0.00
50551	Dist Trans - Inspect & Test	0.00
50650	Dist Meters-Reverification	22,376.33
50651	Dist Meters-Dispute Test	0.00
50652	Dist Meters-Seal Extension	0.00
50653	Dist Meters-Technical Training	0.00
50654	Dist Meters-Computer Costs	0.00
50655	Dist Meters-Other	25.75
50701	Customer Premises-Stakeouts	15,714.60
50702	Customer Fire & No Power Calls	642.17
50703	Customer Station Maintenance	1,024.76
50800	Engineering & Operations	10,430.00
50801	Engineering & Ops Training	2,120.23
50950	O/H Lines Op-Rentals Paid	10,271.06
51140	Substation Maintenance	0.00
51141	Substn Mtce-Land & Building	0.00

51142	Substn Mtce-Other	0.00	51142	Substn Mtce-Other	0.00
51200	O/H Line Mtce-Poles	218,728.95	51200	O/H Line Mtce-Poles	19,110.09
51201	O/H Line Mtce-Temp Services	-5,131.71	51201	O/H Line Mtce-Temp Services	608.62
51250	O/H Line Mtce-Conductor	120,482.32	51250	O/H Line Mtce-Conductor	61,125.55
51251	O/H Line Mtce-Insul Washing	10,560.00	51251	O/H Line Mtce-Insul Washing	0.00
51252	O/H Line Mtce-Serv Upgrades	78,129.20	51252	O/H Line Mtce-Serv Upgrades	0.00
51254	O/H Line Mtce-Other	1,195.53	51254	O/H Line Mtce-Other	9,377.65
51350	Tree Trimming & ROW Mtce	57,321.05	51350	Tree Trimming & ROW Mtce	5,403.36
51450	U/G Line Mtce-Conduit	18,334.39	51450	U/G Line Mtce-Conduit	688.48
51500	U/G Line Mtce-Cable	312,743.50	51500	U/G Line Mtce-Cable	461.33
51501	U/G Line Mtce-Other	2,185.23	51501	U/G Line Mtce-Other	0.00
51600	Dist Transformer Mtce	37,614.98	51600	Dist Transformer Mtce	6,378.92
51601	Dist Transformer Painting	4,391.73	51601	Dist Transformer Painting	0.00
51602	Dist Transformer Other	1,799.24	51602	Dist Transformer Other	0.00
51700	Sentinel Light Mtce - Labour	0.00	51700	Sentinel Light Mtce - Labour	182.74
51720	Sentinel Lt Mtce - Mat & ExP	0.00	51720	Sentinel Lt Mtce - Mat & ExP	0.00
51750	Dist Meter Maintenance	32,397.93	51750	Dist Meter Maintenance	910.43
53050	Bill & Collect - Supervision	106,040.86	53050	Bill & Collect - Supervision	3,008.04
53100	Reading-Labour, Vehicles & Exp	-510.21	53100	Reading-Labour, Vehicles & Exp	17,456.57
53101	Reading-Contract Services	150,585.85	53101	Reading-Contract Services	50,350.70
53102	Reading-Supplies	0.00	53102	Reading-Supplies	50.00
53109	Reading-Other	0.00	53109	Reading-Other	0.00
53150	Billing-Labour & Expenses	105,182.17	53150	Billing-Labour & Expenses	17,941.67
53151	Billing-Postage	158,385.70	53151	Billing-Postage	23,479.99
53152	Billing-Stationery & Supplies	12,813.12	53152	Billing-Stationery & Supplies	5,375.64
53153	Billing-Computer Expenses	44,421.23	53153	Billing-Computer Expenses	25,220.39
53154	Billing-Equipment Costs	0.00	53154	Billing-Equipment Costs	0.00
53155	Billing-Printing & Stuffing	34,737.82	53155	Billing-Printing & Stuffing	12,615.29

53156	Billing-Contract Delivery	0.00	53156	Billing-Contract Delivery	0.00
53159	Billing-Other	139,256.51	53159	Billing-Other	46,667.26
53200	Collecting-Lab, Vehicles $ Exp	479,986.12	53200	Collecting-Lab, Vehicles $ Exp	82,320.40
53201	Collecting-Postage	4,367.12	53201	Collecting-Postage	0.00
53202	Collecting-Stationery & Suppli	8,183.80	53202	Collecting-Stationery & Suppli	2,160.10
53203	Collecting-Equipment Costs	0.00	53203	Collecting-Equipment Costs	76.00
53205	Collecting-Visa/Bank Card	1,938.11	53205	Collecting-Visa/Bank Card	1,107.00
53209	Collecting-Other	67,034.97	53209	Collecting-Other	1,529.44
53250	Collecting-Cash Over & Short	426.17	53250	Collecting-Cash Over & Short	-490.33
53350	Billing-Bad Debts	40,381.87	53350	Billing-Bad Debts	11,417.68
53351	Billing-Conversion Adjustments	0.00	53351	Billing-Conversion Adjustments	0.00
53550	Billing-Bad Debts	0.00	53550	Billing-Bad Debts	0.00
54100	Community Relations-Xmas Lts	3,384.58	54100	Community Relations-Xmas Lts	986.78
54101	Community Relations-Other	58,354.16	54101	Community Relations-Other	3,920.69
55150	Sales Exp-Advertising	9,968.02	55150	Sales Exp-Advertising	2,861.34
56051	Director's Lab & Expense	109,467.04	56051	Director's Lab & Expense	7,087.77
56100	Administration Labour & Exp	508,372.85	56100	Administration Labour & Exp	179,368.82
56101	Admin-Vehicle Exp Unit # 15	9,402.88	56101	Admin-Vehicle Exp Unit # 15	0.00
56102	Admin-Vehicle Exp Unit # 16	4,124.39	56102	Admin-Vehicle Exp Unit # 16	0.00
56103	Admin-Vehicle Exp Unit # 17	2,985.51	56103	Admin-Vehicle Exp Unit # 17	0.00
56104	Admin-Vehicle Exp Unit # 18	3,549.33	56104	Admin-Vehicle Exp Unit # 18	0.00
56150	Office Labour & Expenses	192,954.09	56150	Office Labour & Expenses	92,870.59
56151	Admin-Awards & Staff Functions	22,515.82	56151	Admin-Awards & Staff Functions	0.00
56152	Admin-Training, Seminars	1,792.95	56152	Admin-Training, Seminars	540.00
56300	OUTSIDE SERVICES EMPLOYED	0.00	56300	OUTSIDE SERVICES EMPLOYED	0.00
56350	Insurance-Admin Bldgs	8,382.00	56350	Insurance-Admin Bldgs	10,332.36
56351	Insurance-Substations	14,850.00	56351	Insurance-Substations	6,653.02
56352	Insurance-O/H Lines	15,350.00	56352	Insurance-O/H Lines	0.00

56353	Insurance-U/G Lines	15,350.00	56353	Insurance-U/G Lines	0.00
56354	Insurance-Transformers	15,350.00	56354	Insurance-Transformers	0.00
56550	Admin-Fees(Audit, MEA, etc)	353,495.80	56550	Admin-Fees(Audit, MEA, etc)	52,220.95
56700	Admin Bldg-Rental	270,000.00	56700	Admin Bldg-Rental	8,120.45
56750	Admin Bldg-Lab & Vehicle	94.30	56750	Admin Bldg-Lab & Vehicle	0.00
56751	Admin Bldg-Janitorial	21,121.46	56751	Admin Bldg-Janitorial	0.00
56752	Admin Bldg-Grounds Mtce	20,625.33	56752	Admin Bldg-Grounds Mtce	10,910.13
56753	Admin Bldg-Utilities	68,935.55	56753	Admin Bldg-Utilities	0.00
56754	Admin Bldg-Security	3,678.41	56754	Admin Bldg-Security	0.00
56755	Admin Bldg-HVAC Mtce	7,914.91	56755	Admin Bldg-HVAC Mtce	0.00
56756	Admin Bldg-Minor Upgrades	43.17	56756	Admin Bldg-Minor Upgrades	0.00
56759	Admin Bldg-Other	3,323.64	56759	Admin Bldg-Other	0.00
56760	Telephone SC/LD/Eq Rent	22,231.77	56760	Telephone SC/LD/Eq Rent	0.00
56761	Telephone-Cellular	5,454.36	56761	Telephone-Cellular	323.51
56762	Telephone-Other	7,230.07	56762	Telephone-Other	0.00
56770	Admin-Computer Maintenance	1,150.74	56770	Admin-Computer Maintenance	0.00
56771	Admin-Computer Minor Purchases	1,844.19	56771	Admin-Computer Minor Purchases	1,090.37
56772	Admin-Def'd Program Expense	0.00	56772	Admin-Def'd Program Expense	0.00
56773	Admin-Minor Software Purchases	6,523.19	56773	Admin-Minor Software Purchases	0.00
56774	Admin-Software Support	63,885.08	56774	Admin-Software Support	0.00
56775	Admin-Internet Service	8,035.20	56775	Admin-Internet Service	0.00
56779	Admin-Computer Other	1,351.73	56779	Admin-Computer Other	0.00
56780	Admin-Office Equipment Mtce	5,512.61	56780	Admin-Office Equipment Mtce	0.00
56781	Admin-OE Minor Purchases	249.99	56781	Admin-OE Minor Purchases	0.00
56782	Admin-Office Equip Leasing	12,960.02	56782	Admin-Office Equip Leasing	0.00
56789	Admin-Office Equip Other	0.00	56789	Admin-Office Equip Other	0.00
56790	Admin-Office Supplies	14,199.45	56790	Admin-Office Supplies	-836.01
56791	Admin-Freight, Courier, Fax	7,749.67	56791	Admin-Freight, Courier, Fax	0.00

56792	Admin-Postage	3,009.32	56792	Admin-Postage	0.00
56793	Admin-Bank Charges	36,000.67	56793	Admin-Bank Charges	420.32
56799	Admin-Other	0.00	56799	Admin-Other	22,922.32
57050	Amortization Exp-General Plant	3,651,080.93	57050	Amortization Exp-General Plant	261,332.21
57051	Amortization Exp-Office Equip	16,623.51	57051	Amortization Exp-Office Equip	1,012.91
57052	Amortization Exp-Comp Hardware	56,953.63	57052	Amortization Exp-Comp Hardware	7,324.90
57053	Amortization Exp-Comp Software	200,683.40	57053	Amortization Exp-Comp Software	38,234.14
57054	Amortization Exp-Water Heaters	0.00	57054	Amortization Exp-Water Heaters	0.00
57055	Amortization Exp-Load Mgmnt	0.00	57055	Amortization Exp-Load Mgmnt	0.00
57056	Amortization Exp-Sentinel Lts	265.93	57056	Amortization Exp-Sentinel Lts	0.00
57057	Amortization Exp-Street Lts	0.00	57057	Amortization Exp-Street Lts	0.00
57059	Amortization Exp-Cont Cap	-540,828.82	57059	Amortization Exp-Cont Cap	-15,399.87
60050	Interest Exp-Debentures	0.00	60050	Interest Exp-Debentures	30,985.00
60350	Interest Exp-Customer Deposits	114,163.87	60350	Interest Exp-Customer Deposits	5,903.52
60359	Interest Exp-Other	1,374,995.48	60359	Interest Exp-Other	108,926.00
61050	Property Taxes-Substations	40,410.74	61050	Property Taxes-Substations	14,351.04
61051	Property Taxes-O/H Lines	920.15	61051	Property Taxes-O/H Lines	0.00
61052	Property Taxes-Buildings	66,174.92	61052	Property Taxes-Buildings	0.00
61053	Capital Tax	150,000.00	61053	Capital Tax	0.00
61100	Income Taxes	1,924,999.27	61100	Income Taxes	37,288.83
63050	Extraordinary Income	0.00	63050	Extraordinary Income	0.00
63100	Extraordinary Deductions	0.00	63100	Extraordinary Deductions	0.00
90190	Inclement Weather	43,895.71	90190	Inclement Weather	0.00
90200	Unproductive Labour	0.00	90200	Unproductive Labour	2,128.72
90210	Sfty Mtgs, Line Schl, Seminars	53,818.64	90210	Sfty Mtgs, Line Schl, Seminars	1,712.99
90211	Unproductive Labour	19,622.22	90211	Unproductive Labour	0.00
90220	Small Tool & Equip Purchases	23,880.12	90220	Small Tool & Equip Purchases	1,201.91
90230	Clothing	15,591.68	90230	Clothing	37.04

90240	Meals & Allowances	1,146.63
90250	Major Tool & Equip Depr	20,496.92
90260	Tool & Com Equip Mtce	16,444.55
90270	Tool & Equip Demos & Training	0.00
90280	Tool & Equip Rent & Lease	288.40
90290	Tool & Equip Exp Allocated	0.00
90410	Stores-Labour & Expense	46,672.97
90420	Stores-Supplies & Expense	6,980.75
90430	Stores-Inventory Adjustment	178,793.77
90440	Stores-Equipment Mtce	574.26
90450	Stores-Building Mtce	44.39
90460	Stores-Equipment Depreciation	5,133.13
90470	Stores-Variance	0.00
90480	Stores - Minor Material Purch	0.00
90490	Stores-Expense Allocated	-898.79
90510	S/C-Furn, Equip & Supplies	3,278.84
90520	S/C-Bldg Mtce	0.00
90530	S/C-Equipment Mtce	0.00
90540	S/C-Equipment Rent & Lease	226.30
90550	S/C-Property Tax & Insurance	0.00
90590	S/C-Expense Allocated	0.00
90610	P/R Burden-Retirees' Benefits	14,698.57
90710	Rolling Stock-Licences	8,074.00
90720	Rolling Stock-Supplies & Exp	1,864.45
90730	Rolling Stock-Insurance	7,427.00
90740	Rolling Stock-Mtce, Gas & Oil	126,688.97
90741	Vehicle Exp Unit # 02	2,554.68
90742	Vehicle Exp Unit #10	4,081.95

90240	Meals & Allowances	62.88
90250	Major Tool & Equip Depr	0.00
90260	Tool & Com Equip Mtce	0.00
90270	Tool & Equip Demos & Training	0.00
90280	Tool & Equip Rent & Lease	0.00
90290	Tool & Equip Exp Allocated	14,197.46
90410	Stores-Labour & Expense	9,275.39
90420	Stores-Supplies & Expense	752.48
90430	Stores-Inventory Adjustment	0.00
90440	Stores-Equipment Mtce	0.00
90450	Stores-Building Mtce	47.05
90460	Stores-Equipment Depreciation	0.00
90470	Stores-Variance	0.00
90480	Stores - Minor Material Purch	0.00
90490	Stores-Expense Allocated	532.18
90510	S/C-Furn, Equip & Supplies	0.00
90520	S/C-Bldg Mtce	0.00
90530	S/C-Equipment Mtce	0.00
90540	S/C-Equipment Rent & Lease	0.00
90550	S/C-Property Tax & Insurance	0.00
90590	S/C-Expense Allocated	0.00
90610	P/R Burden-Retirees' Benefits	0.00
90710	Rolling Stock-Licences	20,892.09
90720	Rolling Stock-Supplies & Exp	0.00
90730	Rolling Stock-Insurance	2,408.73
90740	Rolling Stock-Mtce, Gas & Oil	0.00
90741	Vehicle Exp Unit # 02	0.00
90742	Vehicle Exp Unit #10	0.00

90750	Rolling Stock-Building Mtce	7,418.25
90760	Rolling Stock-Amortization	207,818.45
90770	Rolling Stock-Property Tax/Ins	0.00
90790	Rolling Stock-Exp Allocated	-377,485.01
90810	Engineering-Lab, Vehicle & Exp	213,226.31
90820	Engineering-Supplies & Expense	22,720.74
90830	Engineering-Contract Drafting	450.00
90840	Engineering-Computer Expenses	0.00
90890	Engineering-Expense Allocated	-268,672.27
90900	Payroll Burdens	1,920.00
90910	P/R Burden - UIC	4,444.68
90920	P/R Burden - CPP	9,345.51
90930	P/R Burden - Emp Health Tax	11,667.54
90940	P/P Burden-Pension & Insurance	35,926.24
90941	Employee Future Benefits Exp	14,840.00
90950	PB-Sick Time	65,497.43
90951	PB-Vacation	177,124.97
90952	PB-Stats/Bereave/Personal etc	245,329.28
90960	P/R Burden - Workers' Comp	1,904.56
90970	P/R Burden - EHC,Dental,Vision	55,453.96
90971	P/R Burden - Future Benefits	0.00
90980	P/R Burden - LT Disability Ins	13,188.40
90990	Payroll Burden Allocated	-1,043,499.15
91000	Contributed Capital expense	0.00
91010	Contributed Capital Expense	0.00
91200	Contributed Capital Amortized	0.00
91210	Contributed Capital Amortized	0.00
91220	Accumulated Contributed	0.00

90750	Rolling Stock-Building Mtce	7,444.01
90760	Rolling Stock-Amortization	0.00
90770	Rolling Stock-Property Tax/Ins	0.00
90790	Rolling Stock-Exp Allocated	4,964.70
90810	Engineering-Lab, Vehicle & Exp	0.00
90820	Engineering-Supplies & Expense	0.00
90830	Engineering-Contract Drafting	0.00
90840	Engineering-Computer Expenses	-26,464.13
90890	Engineering-Expense Allocated	0.00
90900	Payroll Burdens	460.38
90910	P/R Burden - UIC	1,111.15
90920	P/R Burden - CPP	691.44
90930	P/R Burden - Emp Health Tax	7,401.47
90940	P/P Burden-Pension & Insurance	0.00
90941	Employee Future Benefits Exp	-6,295.47
90950	PB-Sick Time	23,192.09
90951	PB-Vacation	4,038.36
90952	PB-Stats/Bereave/Personal etc	536.31
90960	P/R Burden - Workers' Comp	6,234.56
90970	P/R Burden - EHC,Dental,Vision	0.00
90971	P/R Burden - Future Benefits	6,681.88
90980	P/R Burden - LT Disability Ins	-83,245.67
90990	Payroll Burden Allocated	0.00
91000	Contributed Capital expense	0.00
91010	Contributed Capital Expense	0.00
91200	Contributed Capital Amortized	0.00
91210	Contributed Capital Amortized	0.00
91220	Accumulated Contributed	0.00

91300	Employee Benefit Liability	0.00
91310	Employee Benefit Expense	0.00
999991	PA O/H re-allocation clearing	0.00
999999	Suspense (System Generated)	0.00

91300	Employee Benefit Liability	0.00
91310	Employee Benefit Expense	0.00
999991	PA O/H re-allocation clearing	0.00
999999	Suspense (System Generated)	0.00

2008

NEWMARKET

Account #	ACC_NAME	YTD Actual
10050	Cash In Bank	6,084,468.17
10051	Payroll Bank Account	0.00
10052	U S Bank Account	26,260.00
10053	U S Exchange	0.00
10100	Permanent Cash Advances	0.00
10110	Temporary Cash Advances	0.00
10600	Term Deposits	0.00
10700	Current Investments	1,835,824.71
10701	Current Investments premium	14,191.00
11000	Customer Accounts Receivable	6,017,076.21
11100	Other Accounts Receivable	343,458.39
11101	AR-Municipal St Lt Maintenance	65,142.10
11102	AR-Billing Adjustments	-0.02
11103	AR-Customer Time Payments	0.00
11104	AR-Recoverable Work	0.00
11105	AR- OMERS Overpayment	0.00
11106	AR-Accounts to Clo Agent	0.00
11107	Suspense	0.00
11108	Consumer Deposits Suspense	0.00
11109	Accounts Receivable Suspense	0.00
11110	Letters of Credit Suspense	0.00
11111	AR-Municipal St Lt Capital	0.00
11112	AR-NHHI	160,417.00
11113	1443393 Ontario Inc.	121,335.07
11114	Retirements	0.00

TAY

Account #	ACC_NAME	YTD Actual
10050	Cash In Bank	588,464.20
10051	Payroll Bank Account	0.00
10052	U S Bank Account	0.00
10053	U S Exchange	0.00
10100	Permanent Cash Advances	0.00
10110	Temporary Cash Advances	0.00
10600	Term Deposits	0.00
10700	Current Investments	0.00
10701	Current Investments premium	0.00
11000	Customer Accounts Receivable	323,558.17
11100	Other Accounts Receivable	70,867.77
11101	AR-Municipal St Lt Maintenance	0.00
11102	AR-Billing Adjustments	0.00
11103	AR-Customer Time Payments	0.00
11104	AR-Recoverable Work	0.00
11105	AR- OMERS Overpayment	0.00
11106	AR-Accounts to Clo Agent	0.00
11107	Suspense	0.00
11108	Consumer Deposits Suspense	0.00
11109	Accounts Receivable Suspense	0.00
11110	Letters of Credit Suspense	0.00
11111	AR-Municipal St Lt Capital	0.00
11112	AR-NHHI	48,547.42
11113	1443393 Ont Inc	0.00
11114	Retirements	37,557.06

11200	Unbilled Revenue	7,981,177.00	11200	Unbilled Revenue	920,551.72
11300	Allowance for Doubtful Acct	-255,335.39	11300	Allowance for Doubtful Acct	-43,547.12
11700	Notes Receivable	0.00	11700	Notes Receivable	0.00
11800	Prepaid Expense	258,510.96	11800	Prepaid Expense	33,899.98
11801	Leased Vehicles	0.00	11801	Leased Vehicles	0.00
11802	Upper Canada Energy Alliance	-1,372.39	11802	Upper Canada Energy Alliance	0.00
11803	Prepaid Expense- ERA	0.00	11803	Prepaid Expense- ERA	0.00
11900	Other Current Assets	1,551.63	11900	Other Current Assets	0.00
13300	Inventory	1,159,786.12	13300	Inventory	104,352.77
13301	Inventory-Suspense	0.00	13301	Inventory-Suspense	0.00
13302	Inventory-Default	-107,000.00	13302	Inventory-Default	0.00
13400	Inventory - Water St Retail	0.00	13400	Inventory - Water St Retail	0.00
14600	Long Term Rec-Billing Adj	0.00	14600	Long Term Rec-Billing Adj	0.00
14601	LT Rec - OMERS Overpayment	0.00	14601	LT Rec - OMERS Overpayment	0.00
14602	LT Rec - Cust Time Payment	0.00	14602	LT Rec - Cust Time Payment	0.00
15080	Other Regulatory Assets	0.00	15080	Other Regulatory Assets	45,024.85
15087	Other Regulatory Assets - CC	0.00	15087	Other Regulatory Assets-CC	6,281.55
15180	Retail Cost Variance - Retail	15,389.90	15180	Retail Cost Variance - Retail	-942.83
15187	Retail Cost Var - Retail CC	0.00	15187	Retail Cost Var -Retail CC	-102.96
15250	Misc Deferred Debits	0.00	15250	Deferred Charges	2,170.51
15251	Misc Deferred Debits - CC	0.00	15251	Misc Deferred Debits - CC	155.79
15252	Deferred Charges-Amortization	0.00	15252	Deferred Charges-Amortization	0.00
15253	UCEA Inc	0.00	15253	UCEA Inc	0.00
15254	Deferred Charges-Recovery	0.00	15254	Deferred Charges-Recovery	0.00
15480	Retail Cost Variance - STR	15,389.90	15480	Retail Cost Variance - STR	1,280.33
15487	Retail Cost Variance - STR-CC	0.00	15487	Retail Cost Variance - STR-CC	93.57
15500	Low Voltage Variance - Revenue	725.19	15500	Low Voltage Variance-Revenue	-147,277.59
15501	Low Voltage Variance - Costs	0.00	15501	Low Voltage Variance-Costs	147,869.41

15502	LV METERING CHARGE	0.00	15502	LV METERING CHARGE	0.00
15503	LV METERING MNTHLY CHARGE	0.00	15503	LV METERING MNTHLY CHARGE	0.00
15507	Low Voltage Variance - CC	0.00	15507	Low Voltage Variance-CC	255.28
15550	Smart Meter Capital Expenditur	0.00	15550	Smart Meter Capital Expenditur	0.00
15551	Smart Meter Cap/Rec Offset Var	0.00	15551	Smart Meter Cap/Rec Offset Var	-199,492.89
15560	Smart Meter - OM&A	49,914.41	15560	Smart Meter - OM&A	0.00
15561	Smart Meter - OM&A Revenue	0.00	15551	Smart Meter - OM&A Revenue	0.00
15567	Smart Meter - OM&A CC	0.00	15567	Smart Meter - OM&A CC	0.00
15620	Deferred PILS	0.00	15620	Deferred PILS	125,084.38
15627	Deferred PILS - CC	0.00	15627	Deferred PILS - CC	9,857.58
15630	Deferred PILS Contra	0.00	15630	Deferred PILS - Contra	-123,821.40
15637	Deferred PILS Contra CC	0.00	15637	Deferred PILS - Contra-CC	-11,120.56
15650	Conserve & Demand Revenue	-1,267,000.00	15650	Conserve & Demand Revenue	0.00
15651	Gateway Project	0.00	15651	Gateway Project	0.00
15652	Residential	355,414.46	15652	Residential	-257.48
15653	Affordable/Social Housing	385,116.25	15653	Affordable/Social Housing	0.00
15654	Small Business	0.00	15654	Small Business	0.00
15655	Business/Commerical/Industrial	79,886.43	15655	Business/Commerical/Industrial	0.00
15656	Education Program	158,611.00	15656	Education Program	11,369.13
15657	Other Programs/Discretionary	98,773.07	15657	Other Programs/Discretionary	30,917.55
15658	Distributions System studies	0.00	15658	Distributions System studies	3,874.53
15659	Program Develop & Monitoring	141,801.08	15659	Program Develop & Monitoring	3,612.98
15660	C&DM Recovered From Customers	0.00	15660	C&DM Recovered From Customers	-41,808.83
15700	Transition Costs	94,365.70	15700	Transition Costs	0.00
15701	Transition Costs - Recovery	0.00	15701	Transition Costs - Recovery	0.00
15707	Transition Costs - CC	0.00	15707	Transition Costs - CC	0.00
15710	Pre Market Energy	0.00	15710	Pre Market Energy	0.00
15711	Pre Market Energy-Residential	0.00	15711	Pre Market Energy-Residential	0.00

15712	Pre Market Energy-GS LT 50	0.00
15713	Pre Market Energy-GS GT 50 kW	0.00
15714	Pre Market Energy-GS GT 50 kWh	0.00
15715	Pre Market Energy-Street Light	0.00
15716	Pre Market Energy-Sentinel Lts	0.00
15718	Pre Market - Variance Recovery	0.00
15800	RSVA-Whlsle Market Serv Rev	-21,517,731.17
15801	RSVA-Whlsle Market Serv Chg	19,516,948.11
15802	RSVA-WMS Fixed Chg Settltment	1,000,639.74
15807	RSVA-WMS CC	0.00
15808	RSVA-WMS - Recovery	0.00
15809	RSVA-WMS Unbilled	-529,343.13
15820	RSVA-One Time Charges-Revenue	0.00
15821	RSVA-One Time Charges-Charges	92,200.86
15827	RSVA-One Time Charges-CC	0.00
15840	RSVA-Trans Network Revenue	-18,164,704.95
15841	RSVA-Trans Network Charges	19,116,469.19
15842	RSVA-Trans Meter Credit	-57,950.00
15847	RSVA - Trans Network CC	0.00
15848	RSVA-Trans Network Recovery	0.00
15849	RSVA - Trans Network Unbilled	0.00
15860	RSVA-Trans Connection Revenue	-15,968,262.70
15861	RSVA-Trans Connection Charges	16,270,140.64
15867	RSVA-Trans Connection CC	0.00
15868	RSVA-Trans Connection Recovery	0.00
15869	RSVA-Trans Unbilled	-848,011.28
15880	RSVA-Power Pd By Customers	-136,425,863.56
15881	RSVA-Power Purchased IESO	261,590,087.81

15712	Pre Market Energy-GS LT 50	0.00
15713	Pre Market Energy-GS GT 50 kW	0.00
15714	Pre Market Energy-GS GT 50 kWh	0.00
15715	Pre Market Energy-Street Light	0.00
15716	Pre Market Energy-Sentinel Lts	0.00
15718	Pre Market - Variance Recovery	0.00
15800	RSVA-Whlsle Market Serv Rev	-1,126,812.69
15801	RSVA-Whlsle Market Serv Chg	1,151,789.40
15802	RSVA-WMS Fixed Chg Settltment	0.00
15807	RSVA-WMS CC	1,928.33
15808	RSVA-WMS - Recovery	0.00
15809	RSVA-WMS Unbilled	-46,078.06
15820	RSVA-One Time Charges-Revenue	0.00
15821	RSVA-One Time Charges-Charges	-2,427.88
15827	RSVA-One Time -CC	-312.62
15840	RSVA-Trans Network Revenue	-959,231.83
15841	RSVA-Trans Network Charges	897,856.82
15842	RSVA-Trans Meter Credit	0.00
15847	RSVA-Trans Network CC	-3,955.84
15848	RSVA-Trans Network Recovery	0.00
15849	RSVA-Trans Network Unbilled	-39,431.29
15860	RSVA-Trans Connection Revenue	-841,771.45
15861	RSVA-Trans Connection Charges	584,233.56
15867	RSVA-Trans Connection CC	-62,613.05
15868	RSVA-Trans Connection Recovery	0.00
15869	RSVA-Trans Unbilled	-34,630.70
15880	RSVA-Power Pd By Customers	-827,341.96
15881	RSVA-Power purchase IESO	10,008,320.30

15882	Spot Price Pd By Customers	-120,161,877.68	15882	Spot Price Pd By Customers	-3,776,745.37
15883	Fixed Price Pd By Customers	-119,685,202.39	15883	Fixed Price Pd By Customers	-8,163,910.91
15884	Fixed Price Variance Account	133,121,451.41	15884	Fixed Price Variance Account	3,269,877.78
15885	Fixed Price IMO Settlement	-9,205,148.34	15885	Fixed Price IMO Settlement	0.00
15886	Fixed Price Time of Use Rates	-2,326,689.67	15886	Fixed Price Time of Use Rates	-371,941.80
15887	RSVA - Power - CC	0.00	15887	RSVA - Power - CC	25,664.17
15888	RSVA - Energy Recovery	0.01	15888	RSVA - Energy Recovery	0.00
15889	RSVA-Power Unbilled	-4,880,722.32	15889	RSVA-Power Unbilled	-563,911.01
15890	Pre-Market & RSVA Clearing	0.00	15890	Pre-Market & RSVA Clearing	0.00
15900	Approved Reg Assets	3,446,593.08	15900	Approved Reg Assets	716,661.00
15901	Approved Reg Assets - Recovery	-4,594,983.98	15901	Approved Reg Assets - Recovery	-873,417.47
15907	Approved Reg Assets CC	0.00	15907	Approved Reg Assets -CC	11,826.82
15950	Approved Deferral Balance-2008	0.00	15950	Approved Deferral Balance-2008	0.00
15951	APPROVED DEFERRALRECOVERY2008	0.00	15951	APPROVED DEFERRALRECOVERY2008	0.00
15952	APPROVED SM RECOVERY-2008	0.00	15952	APPROVED SM RECOVERY-2008	0.00
15956	Approved CC to be Recovered-08	0.00	15956	Approved CC to be Recovered-08	0.00
15957	Approved Deferral CC-2008	0.00	15957	Approved Deferral CC-2008	0.00
15959	Unbilled Deferral & Smart M.	0.00	15959	Unbilled Deferral & Smart M.	0.00
15990	Regulated Price Plan Settlemen	-4,088,975.73	15990	Regulated Price Plan Settlemen	-118,285.38
15991	Reg Price Plan retailer settl	-433,347.97	15991	Reg Price Plan retailer settl	341,358.16
15993	Global Adj - CC	0.00	15993	Global Adj - CC	651.71
15994	Global Adj Payabe re lRPP	0.00	15994	Global Adj Payabe re lRPP	0.00
15995	Global adjustment	-2,149,818.70	15995	Global adjustment	3,074.91
15996	Global Adj Settlement Amount	4,665,382.99	15996	Global Adj Settlement Amount	244,926.94
15997	RPP Adj Settlement Amount	-19,275.84	15997	RPP Adj Settlement Amount	-45,421.66
16060	Organization Costs	0.00	16060	Organization Costs	27,610.98
18050	Distribution-Land	3,046,358.25	18050	Distribution-Land	58,066.87
18060	Distribution-Land Rights	222,075.00	18060	Distribution-Land Rights	241,736.72

18200	Dist Stn-Rec Complex	77,383.00	18200	Dist Stn-Rec Complex	0.00
18201	Dist Stn-Legge	656,912.16	18201	Dist Stn-Legge	0.00
18202	Dist Stn-Thompson	994,658.54	18202	Dist Stn-Thompson	0.00
18203	Dist Stn-Broughton/Simmons	1,062,864.26	18203	Dist Stn-Broughton/Simmons	0.00
18204	Dist Stn-Gilbert	1,136,841.73	18204	Dist Stn-Gilbert	0.00
18205	Dist Stn-Andrews	1,113,931.67	18205	Dist Stn-Andrews	0.00
18206	Dist Stn-Leadbeater	688,704.98	18206	Dist Stn-Leadbeater	0.00
18207	Dist Stn-Cook	504,800.39	18207	Dist Stn-Cook	0.00
18208	Dist Stn-Twinney	1,262,582.97	18208	Dist Stn-Twinney	0.00
18209	Dist Stn-S/E Quadrant	842,458.09	18209	Dist Stn-S/E Quadrant	0.00
18210	Dist Stn-Miscellaneous	17,751.55	18210	Dist Stn-Miscellaneous	0.00
18211	Dist Stn Port McNicholl	0.00	18211	Dist Stn Port McNicholl	108,852.49
18212	Dist Stn Victoria Harbour	0.00	18212	Dist Stn Victoria Harbour	288,429.95
18213	Dist Stn Waubaushene	0.00	18213	Dist Stn Waubaushene	98,161.72
18214	Port McNicholl MS 2	0.00	18214	Port McNicholl MS 2	25,113.34
18300	Dist Lines O/H Poles	12,410,040.77	18300	Dist Lines O/H Poles	1,702,963.29
18301	Inventory Holding - O/H Poles	0.00	18301	Inventory Holding - O/H Poles	0.00
18350	Dist Lines O/H Conductor	14,755,661.13	18350	Dist Lines O/H Conductor	1,500,726.04
18351	Invent. Holding- O/H Conductor	0.00	18351	Invent. Holding- O/H Conductor	0.00
18400	Dist Lines U/G Conduit	7,518,726.99	18400	Dist Lines U/G Conduit	63,699.67
18401	Inventory Holding-U/G Conduit	0.00	18401	Inventory Holding-U/G Conduit	0.00
18450	Dist Lines U/G Conductor	23,343,595.55	18450	Dist Lines U/G Conductor	314,790.02
18451	Invent. Holding-U/G Conductor	0.00	18451	Invent. Holding-U/G Conductor	0.00
18500	Distribution Transformers	15,152,555.85	18500	Distribution Transformers	1,093,479.21
18501	Invent. Holding-Transformers	0.00	18501	Invent. Holding-Transformers	0.00
18550	Services	5,230,978.18	18550	Services	1,279,285.11
18551	44 KV CAPITAL STUDY	6,530.26	18551	44 KV CAPITAL STUDY	0.00
18552	13.8 KV CAPITAL STUDY	2,517.15	18552	13.8 KV CAPITAL STUDY	0.00

18600	Distribution Meters	4,369,778.48	18600	Distribution Meters	32,515.14
18610	Smart Meters	4,346,759.40	18610	Smart Meters	524,259.69
18650	Wholesale Meters	931,181.51	18650	Wholesale Meters	0.00
18750	Distribution Street Lights	0.00	18750	Distribution Street Lights	0.00
18990	Capital Asset Management	0.00	18990	Capital Asset Management	0.00
189999	Capital Holding Account	0.00	189999	Capital Holding Account	0.00
19050	General Plant - Land	89.70	19050	General Plant - Land	0.00
19080	Buildings-Eagle Street	0.00	19080	Buildings-Eagle Street	279,019.69
19081	Leasehold Imp-Steven Court	456,691.25	19081	Leasehold Imp-Steven Court	0.00
19082	Buildings-Water Street	0.00	19082	Buildings-Water Street	0.00
19083	Buildings-Other	0.00	19083	Buildings-Other	0.00
19150	Office Equipment	285,567.97	19150	Office Equipment	66,805.11
19200	Computer Hardware	722,808.81	19200	Computer Hardware	115,827.96
19250	Computer Software	1,185,101.48	19250	Computer Software	280,380.17
19300	Transportation Equipment	3,667,992.39	19300	Transportation Equipment	335,232.23
19350	Stores Equipment	144,862.67	19350	Stores Equipment	6,384.82
19400	Tools, Shop & Garage Equipment	444,027.79	19400	Tools, Shop & Garage Equipment	67,763.22
19450	Measurement & Testing Equip	102,535.07	19450	Measurement & Testing Equip	0.00
19650	Water Heater Rental units	0.00	19650	Water Heater Rental units	0.00
19800	System Supervisory Equipment	731,769.42	19800	System Supervisory Equipment	0.00
19810	System Optimization Study	10,871.57	19810	System Optimization Study	0.00
19850	Sentinel Light Rental Units	13,085.27	19850	Sentinel Light Rental Units	9,966.47
19900	Amalco Capital	0.00	19900	Amalco Capital	0.00
19950	Cont Cap to be Amortized	-15,466,241.31	19950	Cont Cap to be Amortized	-370,979.36
199999	Fixed Assets Suspense	0.00	199999	Fixed Assets Suspense	0.00
20550	Construction In Progress	0.00	20550	Construction In Progress	0.00
21050	Accum Dep-Current Provision	0.00	21050	Accum Dep-Current Provision	0.00
21051	Accum Amor-Organization Costs	0.00	21051	Accum Amor-Organization Costs	-22,088.00

21052	Accum Amor-Buildings Other	0.00	21052	Accum Amor-Buildings Other	-85,048.30
21053	Accum Amor-Stations	-4,247,777.76	21053	Accum Amor-Stations	-288,934.57
21054	Accum Amor-O/H Lines	-13,123,610.43	21054	Accum Amor-O/H Lines	-2,102,618.89
21055	Accum Amor-Land Rights	-3,701.25	21055	Accum Amor-Land Rights	-112,606.10
21056	Accum Amor-U/G Lines	-16,693,797.13	21056	Accum Amor-U/G Lines	-884,544.71
21057	Accum Amor-Transformers	-7,333,019.51	21057	Accum Amor-Transformers	-642,501.90
21058	Accum Amor-Meters	-2,804,643.82	21058	Accum Amor-Meters	-104,267.97
21059	Accum Amor-Street Lights	0.00	21059	Accum Amor-Street Lights	0.00
21060	Accum Amor-Office Equipment	-180,743.96	21060	Accum Amor-Office Equipment	-48,959.45
21061	Accum Amor-Computer Equipment	-524,907.50	21061	Accum Amor-Computer Equipment	-58,698.90
21062	Accum Amor-Computer Software	-884,112.38	21062	Accum Amor-Computer Software	-174,844.55
21063	Accum Amor-Stores Equipment	-102,228.58	21063	Accum Amor-Stores Equipment	-6,384.20
21064	Accum Amor-Transportation Equi	-2,368,477.05	21064	Accum Amor-Transportation Equi	-314,168.85
21065	Accum Amor-Tools	-379,007.84	21065	Accum Amor-Tools	-51,508.26
21066	Accum Amor-Water Heaters	0.00	21066	Accum Amor-Water Heaters	0.00
21067	Accum Amor-Leasehold	-374,636.00	21067	Accum Amor-Leasehold	0.00
21068	Accum Amor-System Supervisory	-524,179.69	21068	Accum Amor-System Supervisory	0.00
21069	Accum Amor-Sentinel Lights	-13,085.74	21069	Accum Amor-Sentinel Lights	-9,966.47
21070	Accum Amor-Street Lights	0.00	21070	Accum Amor-Street Lights	0.00
21090	Accum Amor-Cont Cap	3,165,919.29	21090	Accum Amor-Cont Cap	47,303.17
22050	Accounts Payable	-1,206,553.17	22050	Accounts Payable	-97,821.77
22051	A/P-Town Water Billing	-1,303,048.30	22051	A/P-Town Water Billing	0.00
22052	A/P-Power Bill	-4,679,510.15	22052	A/P-Power Bill	0.00
22053	A/P-Income Tax	780,000.34	22053	A/P-Income Tax	0.00
22054	Miscellaneous Accruals	-1,314,379.01	22054	Miscellaneous Accruals	-643,885.60
22055	A/P-MPMA Rebate	-69,202.28	22055	A/P-MPMA Rebate	1,808.38
22056	A/P-Phase 2 Rebate	0.00	22056	A/P-Phase 2 Rebate	0.00
22057	A/P-$75 Rebate	0.00	22057	A/P-$75 Rebate	0.00

22058	Accounts Payable-Default	-3,039.70	22058	Accounts Payable-Default	0.00
22059	A/P-Town Other	-1,469,999.88	22059	A/P-Town Other	-195,000.00
22060	Invoice Settlement-Direct	0.00	22060	Invoice Settlement-Direct	0.00
22061	BRC - Toronto Hydro	0.00	22061	BRC - Toronto Hydro	0.00
22062	BRC - OPG	0.00	22062	BRC - OPG	0.00
22063	BRC - Ontario Hydro	0.00	22063	BRC - Ontario Hydro	0.00
22064	BRC - First Source	0.00	22064	BRC - First Source	0.00
22065	BRC - Ontario Electric Savings	0.00	22065	BRC - Ontario Electric Savings	0.00
22066	BRC - Coral Energy	0.00	22066	BRC - Coral Energy	0.00
22067	BRC - Canadian Choice Energy	0.00	22067	BRC - Canadian Choice Energy	0.00
22068	BRC - Constellation New Energy	0.00	22068	BRC - Constellation New Energy	0.00
22069	BRC - Universal Energy	0.00	22069	BRC - Universal Energy	0.00
22070	BRC - ECNG	0.00	22070	BRC - ECNG	0.00
22071	BRC -Canadian Hydro	0.00	22071	BRC -Canadian Hydro	0.00
22072	BRC - Bullfrog Power	0.00	22072	BRC - Bullfrog Power	0.00
22073	BRC - SEMINC	0.00	22073	BRC - SEMINC	0.00
22074	BRC - Superior Energy	0.00	22074	BRC - Superior Energy	0.00
22075	BRC - Wholesale Energy	0.00	22075	BRC - Wholesale Energy	0.00
22076	BRC - Planet Energy Ontario Co	0.00	22076	BRC - Planet Energy Ontario Co	0.00
22077	BRC - AG ENERGY CO-OP LTD	0.00	22077	BRC - AG ENERGY CO-OP LTD	0.00
22078	BRC - National Energy Corp.	0.00	22078	BRC - National Energy Corp.	0.00
22080	Customer Credit Balances	-1,354,655.13	22080	Customer Credit Balances	-123,438.49
22100	Customer Deposits-Current	-300,000.00	22100	Customer Deposits-Current	-25,000.00
22200	Unused Vacation Pay Accrual	-58,152.61	22200	Unused Vacation Pay Accrual	-5,863.85
22201	Payroll Clearing	-174,328.23	22201	Payroll Clearing	-30,045.05
222011	Interco due to & due from	68,929.33	222011	Interco due to & due from	-68,929.33
22202	Subdivider Lot Levies-Current	-52,586.00	22202	Subdivider Lot Levies-Current	0.00
22250	Other Current Liabilities	0.00	22250	Other Current Liabilities	-183,835.02

22251	Notes and Loans Payable	0.00	22251	Notes and Loans Payable	-4,680.82
22500	Debt Retirement Charges	0.00	22500	Debt Retirement Charges	0.00
22560	AP - IMO	0.00	22560	AP - IMO	0.00
22600	Current Portion Long Term Debt	0.00	22600	Current Portion Long Term Debt	0.00
22601	Current Portion Other Debt	0.00	22601	Current Portion Other Debt	0.00
22640	OPA - Refrigerator Roundup	0.00	22640	OPA - Refrigerator Roundup	0.00
22641	OPA - Summer Savings	0.00	22641	OPA - Summer Savings	0.00
22642	OPA - Peaksaver	0.00	22642	OPA - Peaksaver	0.00
226421	OPA - ERIP	0.00	226421	OPA - ERIP	0.00
226422	OPA-Direct Installs	15,017.20	226422	OPA-Direct Installs	0.00
226423	OPA-Comm Initiative Fund	-27,000.00	226423	OPA-Comm Initiative Fund	0.00
226424	OPA - MEER	0.00	226424	OPA - MEER	0.00
22643	Thermostats - Barrie	0.00	22643	Thermostats - Barrie	0.00
22644	Thermostats - Innisfil	0.00	22644	Thermostats - Innisfil	0.00
22645	Thermostats -Essex	0.00	22645	Thermostats -Essex	0.00
22646	Thermostats -Enwin	0.00	22646	Thermostats -Enwin	0.00
22647	Thermostats -Erie Thames	0.00	22647	Thermostats -Erie Thames	0.00
22648	Thermostats -St Thomas	0.00	22648	Thermostats -St Thomas	0.00
22649	Thermostats -Clinton	0.00	22649	Thermostats -Clinton	0.00
22650	Thermostats -West Perth	0.00	22650	Thermostats -West Perth	0.00
22680	Accrued Interest-L T Debt	0.00	22680	Accrued Interest-L T Debt	0.00
22681	Accrued Interest-Cust Deps	-1,670.11	22681	Accrued Interest-Cust Deps	-2,742.52
22901	GST - ITC 100%	667.75	22901	GST - ITC 100%	7.19
22902	GST - ITC 57.14% St Lts	0.00	22902	GST - ITC 57.14% St Lts	0.00
22903	GST - ITC 50%	0.00	22903	GST - ITC 50%	0.00
22904	GST - Collected	0.00	22904	GST - Collected	-110.50
22905	GST - Remittance	0.00	22905	GST - Remittance	0.00
22909	PST Payable	0.00	22909	PST Payable	0.00

22921	Income Tax Payable	0.10	22921	Income Tax Payable	0.00
22922	CPP Payable	0.00	22922	CPP Payable	0.00
22923	Employment Insurance Payable	0.00	22923	Employment Insurance Payable	0.00
22924	OMERS Payable	0.00	22924	OMERS Payable	0.00
22925	EHT Payable	-3,511.37	22925	EHT Payable	0.00
22926	W.S.I.B. Payable	0.00	22926	W.S.I.B. Payable	0.00
22927	Life Insurance Payable	0.00	22927	Life Insurance Payable	0.00
22928	Garnishee Payable	0.00	22928	Garnishee Payable	0.00
22929	Union Dues	0.00	22929	Union Dues	0.00
229291	RRSP Payable	0.00	229291	RRSP Payable	0.00
23060	Employee Future Benefits	-803,345.00	23060	Employee Future Benefits	-36,512.00
23200	Other Non-Current Liabilities	0.00	23200	Other Non-Current Liabilities	0.00
23201	Deferred Credits	-47,514.40	23201	Deferred Credits	0.00
23300	Subdividers Lot Levies	0.00	23300	Subdividers Lot Levies	0.00
23301	Lot Levies-Single Units	0.00	23301	Lot Levies-Single Units	0.00
23350	Customer Deposits	-2,878,513.94	23350	Customer Deposits	-130,896.24
23351	Construction Deposits	-766,629.80	23351	Construction Deposits	0.00
23352	Retailer Deposits	0.00	23352	Retailer Deposits	0.00
23353	Consumer Deposit Suspense	-25,950.00	23353	Consumer Deposit Suspense	0.00
24050	Other Regulatory Liabilities	0.00	24050	Other Regulatory Liabilities	-641.49
25000	Long Term Debt	0.00	25000	Long Term Debt	-200,000.00
25200	Long Term Debt - Town	-22,000,000.00	25200	Long Term Debt - Town	-1,742,821.00
30220	Lot Levies Transf'd to Equity	-201,720.00	30220	Lot Levies Transf'd to Equity	0.00
30300	Contributed Capital-Equity	-33,468,574.15	30300	Contributed Capital-Equity	-1,742,821.00
30301	Contributed Capital-St Lts	0.00	30301	Contributed Capital-St Lts	0.00
30450	Accumulated Net Income	-1,350,317.36	30450	Accumulated Net Income	-46,556.12
30451	Dividends Paid	3,788,000.00	30451	Dividends Paid	565,000.00
30490	Dividends Declared	4,410,000.00	30490	Dividends Declared	0.00

40060	Energy-Residential	20,107.85	40060	Energy-Residential	0.00
40061	Residential-Dist Customer Chg	-3,888,262.69	40061	Residential-Dist Customer Chg	-783,282.81
40062	Residential-Dist kWh	-3,589,245.77	40062	Residential-Dist kWh	-542,493.73
40063	Residential-Energy kWh	0.00	40063	Residential-Energy kWh	0.00
40064	Residential-Retro Adjustment	0.00	40064	Residential-Retro Adjustment	0.00
40068	Energy-Res-PILS Trans Recovery	324,556.68	40068	Energy-Res-PILS Trans Recovery	352,131.41
40250	Energy-Street Lights	-973.48	40250	Energy-Street Lights	0.00
40251	Energy-Sentinel Lights	0.00	40251	Energy-Sentinel Lights	0.00
40252	Street Light-Dist kW Charge	-28,359.51	40252	Street Light-Dist kW Charge	-5,918.17
40253	Street Light-Energy kW Charge	0.00	40253	Street Light-Energy kW Charge	0.00
40254	Street Light-Retro Adj	0.00	40254	Street Light-Retro Adj	0.00
40255	Street Light-Dist Fixed Chg	-26,558.86	40255	Street Light-Dist Fixed Chg	-5,895.36
40258	St Light-PIL Trans Recovery	3,370.66	40258	St Light-PIL Trans Recovery	1,810.95
40302	Sentinel Light Distribution kW	-3,075.88	40302	Sentinel Light Distribution kW	-273.45
40303	Sentinel Light Energy kW	0.00	40303	Sentinel Light Energy kW	0.00
40305	Sentinel Light Service Charge	-8,547.58	40305	Sentinel Light Service Charge	-144.47
40308	Sent Lt PILS Trans Recovery	379.56	40308	Sent Lt PILS Trans Recovery	777.16
40350	GT 50 - Dist Electric Meter Ad	0.00	40350	GT 50 - Dist Electric Meter Ad	-1,674.00
40351	GS LT 50-Dist Cust Chg	-678,358.11	40351	GS LT 50-Dist Cust Chg	-84,872.11
40352	GS LT 50-Dist kWh Charge	-1,706,305.39	40352	GS LT 50-Dist kWh Charge	-67,646.08
40353	GS LT 50-Energy kWh Charge	0.00	40353	GS LT 50-Energy kWh Charge	0.00
40354	GS LT 50-PIL Trans Recovery	123,720.56	40354	GS LT 50-PIL Trans Recovery	33,986.08
40355	GS GT 50-Dist Cust Charge	-1,706,378.40	40355	GS GT 50-Dist Cust Charge	-29,089.73
40356	GS GT 50-Dist kW Charge	-3,093,856.28	40356	GS GT 50-Dist kW Charge	-67,225.56
40357	GS GT 50-Energy kW Charge	0.00	40357	GS GT 50-Energy kW Charge	0.00
40358	GS GT 50-PIL Trans Recovery	524,307.97	40358	GS GT 50-PIL Trans Recovery	21,132.71
40359	GS GT 50-Retro Adj	0.00	40359	GS GT 50-Retro Adj	0.00
40360	C&DM Recovered From Customers	0.00	40360	C&DM Recovered From Customers	0.00

40500	Energy-Adjustments	-134,868.49	40500	Energy-Adjustments	-34,667.75
40550	Smart Meter Revenue Rec'd	0.00	40550	Smart Meter Revenue Rec'd	0.00
40551	WAP/R - Direct	0.00	40551	WAP/R - Direct	0.00
40552	WAP/GS - Direct	0.00	40552	WAP/GS - Direct	0.00
40553	WAP/R - THESI	0.00	40553	WAP/R - THESI	0.00
40554	WAP/GS - THESI	0.00	40554	WAP/GS - THESI	0.00
40555	WAP/R - OPG	0.00	40555	WAP/R - OPG	0.00
40556	WAP/GS - OPG	0.00	40556	WAP/GS - OPG	0.00
40557	WAP/R - OHE	0.00	40557	WAP/R - OHE	0.00
40558	WAP/GS - OHE	0.00	40558	WAP/GS - OHE	0.00
40559	WAP/R - First Source	0.00	40559	WAP/R - First Source	0.00
40560	WAP/GS - First Source	0.00	40560	WAP/GS - First Source	0.00
40561	WAP/R - Coral Energy	0.00	40561	WAP/R - Coral Energy	0.00
40562	WAP/GS - Coral Energy	0.00	40562	WAP/GS - Coral Energy	0.00
40563	WAP/R - OESC	0.00	40563	WAP/R - OESC	0.00
40564	WAP/GS - OESC	0.00	40564	WAP/GS - OESC	0.00
40565	WAP/R - Cdn Choice	0.00	40565	WAP/R - Cdn Choice	0.00
40566	WAP/GS - Cdn Choice	0.00	40566	WAP/GS - Cdn Choice	0.00
40620	Whlsl Mrkt Services Billed	0.00	40620	Whlsl Mrkt Services Billed	0.00
40640	Whlsl Mrkt Srvcs Blld 1 time	0.00	40640	Whlsl Mrkt Srvcs Blld 1 time	0.00
40660	Retail Transmission Service	0.00	40660	Retail Transmission Service	0.00
40680	Retail Transmission Connection	0.00	40680	Retail Transmission Connection	0.00
40800	SSS Administration Charge	-93,814.46	40800	SSS Administration Charge	-12,363.22
40801	Distribution Wheeling Service	0.00	40801	Distribution Wheeling Service	0.00
40802	Recver Reg Assets prev W/O	0.00	40802	Recver Reg Assets prev W/O	0.00
40820	Retail Service Revenues	-39,872.10	40820	Retail Service Revenues	-2,376.30
40840	STR Revenues	-1,383.50	40840	STR Revenues	-5,593.00
42103	Revenue-Pole Rentals	-57,369.67	42103	Revenue-Pole Rentals	-63,140.03

42250	Revenue-Late Payment Charges	-161,259.73	42250	Revenue-Late Payment Charges	-20,085.42
42350	Revenue-St LT Non-Energy	0.00	42350	Revenue-St LT Non-Energy	0.00
42351	Account Setup	-52,375.00	42351	Account Setup	0.00
42352	Revenue-Reconnection Charges	-28,510.00	42352	Revenue-Reconnection Charges	-15,525.00
42353	Revenue-Collection Charges	-133,947.00	42353	Revenue-Collection Charges	-37,875.00
42354	Change of Occupancy-Final Bill	-43,137.50	42354	Change of Occupancy-Final Bill	0.00
43102	Revenue-Sentinel Lt Rentals	-20,986.80	43102	Revenue-Sentinel Lt Rentals	-1,376.60
43250	Revenue-Sale of Scrap Metals	-10,794.99	43250	Revenue-Sale of Scrap Metals	0.00
43251	Water St-Mark Up on Sales	0.00	43251	Water St-Mark Up on Sales	0.00
43550	Gain on Sale of Assets	0.00	43550	Gain on Sale of Assets	0.00
43600	Loss on Sale of Assets	0.00	43600	Loss on Sale of Assets	0.00
43850	Non-Utility Rental Income	0.00	43850	Non-Utility Rental Income	0.00
43851	Water Heater Rental Income	0.00	43851	Water Heater Rental Income	0.00
43900	Revenue-Miscellaneous	-14,149.00	43900	Revenue-Miscellaneous	-7,351.78
43901	Revenue-Profit on Mat & Serv	-23,710.88	43901	Revenue-Profit on Mat & Serv	-3,034.78
43902	Revenue-Arrears Certificates	-1,505.71	43902	Revenue-Arrears Certificates	-80.90
43903	Revenue-Power Bill Aggregation	0.00	43903	Revenue-Power Bill Aggregation	0.00
43904	Costs re By-passed Meters	10,000.00	43904	Costs re By-passed Meters	0.00
43905	Revenue re By-passed Meters	-29.17	43905	Revenue re By-passed Meters	0.00
44050	Interest Earned	-283,014.83	44050	Interest Earned	-33,183.92
44051	CC on Reg Assets	0.00	44051	CC on Reg Assets	2,970.93
47050	Pre Market & RSVA Clearing	0.00	47050	Pre Market & RSVA Clearing	0.00
47051	Transition Cost Write Off	0.00	47051	Transition Cost Write Off	0.00
47080	Power Purchased - WMS	0.00	47080	Power Purchased - WMS	0.00
47100	Power Purchased-Adjustments	0.00	47100	Power Purchased-Adjustments	0.00
47120	Power Purchased - On Time	0.00	47120	Power Purchased - On Time	0.00
47140	Power Purchased - Network	0.00	47140	Power Purchased - Network	0.00
47160	Power Purchased - Connection	0.00	47160	Power Purchased - Connection	0.00

47250	Competition Transition Charges	0.00	47250	Competition Transition Charges	0.00
50050	Operation Supervision	61,533.46	50050	Operation Supervision	68,268.39
50160	Substn Op'n-Labour	39,172.63	50160	Substn Op'n-Labour	1,443.75
50161	Substn Op'n-Inspect & Tes	25,852.54	50161	Substn Op'n-Inspect & Tes	947.04
50170	Substn Op'n-Supplies & Expense	95.87	50170	Substn Op'n-Supplies & Expense	2,015.54
50200	O/H Line Operation-Labour	18,657.84	50200	O/H Line Operation-Labour	21,716.03
50250	O/H Line Op'n-Supplies & Exp	63,808.05	50250	O/H Line Op'n-Supplies & Exp	0.00
50350	O/H Dist Transformer Operation	627.64	50350	O/H Dist Transformer Operation	2,063.63
50400	U/G Line Op'n-Labour	32,899.58	50400	U/G Line Op'n-Labour	3,319.14
50401	U/G Line Op'n-Stakeouts	209,581.45	50401	U/G Line Op'n-Stakeouts	9,602.07
50450	U/G Line Op'n-Supplies & Exp	16,100.09	50450	U/G Line Op'n-Supplies & Exp	118.15
50451	U/G Line Op'n-Stakeouts	0.00	50451	U/G Line Op'n-Stakeouts	0.00
50550	U/G Dist Transformer Operation	65,964.10	50550	U/G Dist Transformer Operation	147.13
50551	Dist Trans - Inspect & Test	1,179.31	50551	Dist Trans - Inspect & Test	0.00
50650	Dist Meters-Reverification	153,283.31	50650	Dist Meters-Reverification	1,728.85
50651	Dist Meters-Dispute Test	1,774.65	50651	Dist Meters-Dispute Test	0.00
50652	Dist Meters-Seal Extension	6,476.14	50652	Dist Meters-Seal Extension	0.00
50653	Dist Meters-Technical Training	0.00	50653	Dist Meters-Technical Training	0.00
50654	Dist Meters-Computer Costs	0.00	50654	Dist Meters-Computer Costs	0.00
50655	Dist Meters-Other	835.95	50655	Dist Meters-Other	0.00
50701	Customer Premises-Stakeouts	42,854.26	50701	Customer Premises-Stakeouts	25,363.19
50702	Customer Fire & No Power Calls	72,613.41	50702	Customer Fire & No Power Calls	14,262.28
50703	Customer Station Maintenance	11,105.16	50703	Customer Station Maintenance	69.88
50800	Engineering & Operations	0.00	50800	Engineering & Operations	0.00
50801	Engineering & Ops Training	12,702.67	50801	Engineering & Ops Training	237.58
50950	O/H Lines Op-Rentals Paid	10,541.54	50950	O/H Lines Op-Rentals Paid	0.00
51140	Substation Maintenance	51,336.15	51140	Substation Maintenance	1,381.63
51141	Substn Mtce-Land & Building	22,069.15	51141	Substn Mtce-Land & Building	915.00

51142	Substn Mtce-Other	0.00	51142	Substn Mtce-Other	0.00
51200	O/H Line Mtce-Poles	121,581.67	51200	O/H Line Mtce-Poles	-16,431.30
51201	O/H Line Mtce-Temp Services	-26,967.27	51201	O/H Line Mtce-Temp Services	110.35
51250	O/H Line Mtce-Conductor	231,301.23	51250	O/H Line Mtce-Conductor	67,448.63
51251	O/H Line Mtce-Insul Washing	21,587.50	51251	O/H Line Mtce-Insul Washing	0.00
51252	O/H Line Mtce-Serv Upgrades	68,811.68	51252	O/H Line Mtce-Serv Upgrades	-5,123.56
51254	O/H Line Mtce-Other	2,470.44	51254	O/H Line Mtce-Other	1,022.19
51350	Tree Trimming & ROW Mtce	91,568.16	51350	Tree Trimming & ROW Mtce	96,228.22
51450	U/G Line Mtce-Conduit	11,653.89	51450	U/G Line Mtce-Conduit	378.82
51500	U/G Line Mtce-Cable	289,607.31	51500	U/G Line Mtce-Cable	515.74
51501	U/G Line Mtce-Other	5,372.00	51501	U/G Line Mtce-Other	0.00
51600	Dist Transformer Mtce	82,728.16	51600	Dist Transformer Mtce	2,921.70
51601	Dist Transformer Painting	16,121.00	51601	Dist Transformer Painting	0.00
51602	Dist Transformer Other	0.00	51602	Dist Transformer Other	0.00
51700	Sentinel Light Mtce - Labour	0.00	51700	Sentinel Light Mtce - Labour	118.80
51720	Sentinel Lt Mtce - Mat & ExP	0.00	51720	Sentinel Lt Mtce - Mat & ExP	0.00
51750	Dist Meter Maintenance	25,656.66	51750	Dist Meter Maintenance	968.25
53050	Bill & Collect - Supervision	119,869.56	53050	Bill & Collect - Supervision	0.00
53100	Reading-Labour, Vehicles & Exp	-1,065.00	53100	Reading-Labour, Vehicles & Exp	13,779.90
53101	Reading-Contract Services	156,953.05	53101	Reading-Contract Services	52,886.74
53102	Reading-Supplies	0.00	53102	Reading-Supplies	0.00
53109	Reading-Other	0.00	53109	Reading-Other	0.00
53150	Billing-Labour & Expenses	110,373.51	53150	Billing-Labour & Expenses	5,916.60
53151	Billing-Postage	164,331.67	53151	Billing-Postage	24,862.70
53152	Billing-Stationery & Supplies	0.00	53152	Billing-Stationery & Supplies	2,010.24
53153	Billing-Computer Expenses	43,344.00	53153	Billing-Computer Expenses	12,468.36
53154	Billing-Equipment Costs	0.00	53154	Billing-Equipment Costs	0.00
53155	Billing-Printing & Stuffing	44,603.65	53155	Billing-Printing & Stuffing	9,896.93

53156	Billing-Contract Delivery	0.00	53156	Billing-Contract Delivery	0.00
53159	Billing-Other	149,367.91	53159	Billing-Other	40,849.99
53200	Collecting-Lab, Vehicles $ Exp	441,647.80	53200	Collecting-Lab, Vehicles $ Exp	145,688.51
53201	Collecting-Postage	7,334.67	53201	Collecting-Postage	1,300.00
53202	Collecting-Stationery & Suppli	3,220.86	53202	Collecting-Stationery & Suppli	1,034.30
53203	Collecting-Equipment Costs	0.00	53203	Collecting-Equipment Costs	0.00
53205	Collecting-Visa/Bank Card	2,142.78	53205	Collecting-Visa/Bank Card	838.58
53209	Collecting-Other	47,425.09	53209	Collecting-Other	3,562.09
53250	Collecting-Cash Over & Short	-456.68	53250	Collecting-Cash Over & Short	-365.76
53350	Billing-Bad Debts	2,895.00	53350	Billing-Bad Debts	31,752.52
53351	Billing-Conversion Adjustments	0.00	53351	Billing-Conversion Adjustments	0.00
53550	Billing-Bad Debts	111,992.94	53550	Billing-Bad Debts	0.00
54100	Community Relations-Xmas Lts	3,388.46	54100	Community Relations-Xmas Lts	413.27
54101	Community Relations-Other	49,138.74	54101	Community Relations-Other	16,143.99
55150	Sales Exp-Advertising	2,725.00	55150	Sales Exp-Advertising	197.64
56051	Director's Lab & Expense	108,403.46	56051	Director's Lab & Expense	19,718.61
56100	Administration Labour & Exp	545,626.62	56100	Administration Labour & Exp	124,055.55
56101	Admin-Vehicle Exp Unit # 15	2,085.30	56101	Admin-Vehicle Exp Unit # 15	0.00
56102	Admin-Vehicle Exp Unit # 16	6,299.71	56102	Admin-Vehicle Exp Unit # 16	0.00
56103	Admin-Vehicle Exp Unit # 17	3,199.67	56103	Admin-Vehicle Exp Unit # 17	0.00
56104	Admin-Vehicle Exp Unit # 18	0.00	56104	Admin-Vehicle Exp Unit # 18	0.00
56150	Office Labour & Expenses	232,793.07	56150	Office Labour & Expenses	93,234.11
56151	Admin-Awards & Staff Functions	24,749.75	56151	Admin-Awards & Staff Functions	912.38
56152	Admin-Training, Seminars	12,232.37	56152	Admin-Training, Seminars	0.00
56300	OUTSIDE SERVICES EMPLOYED	223,627.50	56300	OUTSIDE SERVICES EMPLOYED	28,156.24
56350	Insurance-Admin Bldgs	15,967.91	56350	Insurance-Admin Bldgs	2,599.43
56351	Insurance-Substations	25,794.31	56351	Insurance-Substations	4,199.08
56352	Insurance-O/H Lines	27,022.61	56352	Insurance-O/H Lines	4,453.03

56353	Insurance-U/G Lines	27,022.61	56353	Insurance-U/G Lines	4,453.03
56354	Insurance-Transformers	27,022.61	56354	Insurance-Transformers	4,453.03
56550	Regulatory Expense	139,208.14	56550	Admin-Fees(Audit, MEA, etc)	-6,905.10
56700	Admin Bldg-Rental	270,000.00	56700	Admin Bldg-Rental	0.00
56750	Admin Bldg-Lab & Vehicle	0.00	56750	Admin Bldg-Lab & Vehicle	0.00
56751	Admin Bldg-Janitorial	21,519.90	56751	Admin Bldg-Janitorial	2,010.00
56752	Admin Bldg-Grounds Mtce	13,238.86	56752	Admin Bldg-Grounds Mtce	2,480.20
56753	Admin Bldg-Utilities	72,663.24	56753	Admin Bldg-Utilities	13,388.09
56754	Admin Bldg-Security	4,088.18	56754	Admin Bldg-Security	2,032.12
56755	Admin Bldg-HVAC Mtce	6,292.00	56755	Admin Bldg-HVAC Mtce	1,200.05
56756	Admin Bldg-Minor Upgrades	3,420.48	56756	Admin Bldg-Minor Upgrades	2,266.47
56759	Admin Bldg-Other	4,755.02	56759	Admin Bldg-Other	547.66
56760	Telephone SC/LD/Eq Rent	23,600.41	56760	Telephone SC/LD/Eq Rent	6,787.28
56761	Telephone-Cellular	4,146.00	56761	Telephone-Cellular	742.05
56762	Telephone-Other	19,489.45	56762	Telephone-Other	0.00
56770	Admin-Computer Maintenance	931.50	56770	Admin-Computer Maintenance	36.62
56771	Admin-Computer Minor Purchases	491.93	56771	Admin-Computer Minor Purchases	107.99
56772	Admin-Def'd Program Expense	0.00	56772	Admin-Def'd Program Expense	0.00
56773	Admin-Minor Software Purchases	10,142.29	56773	Admin-Minor Software Purchases	666.24
56774	Admin-Software Support	71,498.54	56774	Admin-Software Support	8,675.02
56775	Admin-Internet Service	8,140.55	56775	Admin-Internet Service	1,172.70
56779	Admin-Computer Other	0.00	56779	Admin-Computer Other	0.00
56780	Admin-Office Equipment Mtce	7,385.14	56780	Admin-Office Equipment Mtce	515.35
56781	Admin-OE Minor Purchases	693.00	56781	Admin-OE Minor Purchases	0.00
56782	Admin-Office Equip Leasing	10,035.65	56782	Admin-Office Equip Leasing	4,899.09
56789	Admin-Office Equip Other	0.00	56789	Admin-Office Equip Other	0.00
56790	Admin-Office Supplies	21,042.59	56790	Admin-Office Supplies	4,944.04
56791	Admin-Freight, Courier, Fax	5,740.84	56791	Admin-Freight, Courier, Fax	119.67

56792	Admin-Postage	3,740.00	56792	Admin-Postage	956.22
56793	Admin-Bank Charges	35,066.21	56793	Admin-Bank Charges	1,842.11
56799	Admin-Other	460.70	56799	Admin-Other	177.65
57050	Amortization Exp-General Plant	3,748,336.62	57050	Amortization Exp-General Plant	304,805.86
57051	Amortization Exp-Office Equip	18,953.26	57051	Amortization Exp-Office Equip	2,112.99
57052	Amortization Exp-Comp Hardware	53,738.50	57052	Amortization Exp-Comp Hardware	8,785.51
57053	Amortization Exp-Comp Software	203,830.01	57053	Amortization Exp-Comp Software	40,894.98
57054	Amortization Exp-Water Heaters	0.00	57054	Amortization Exp-Water Heaters	0.00
57055	Amortization Exp-Load Mgmnt	0.00	57055	Amortization Exp-Load Mgmnt	0.00
57056	Amortization Exp-Sentinel Lts	237.97	57056	Amortization Exp-Sentinel Lts	0.00
57057	Amortization Exp-Street Lts	0.00	57057	Amortization Exp-Street Lts	0.00
57059	Amortization Exp-Cont Cap	-618,649.65	57059	Amortization Exp-Cont Cap	-14,211.71
60050	Interest Exp-Debentures	0.00	60050	Interest Exp-Debentures	20,004.75
60350	Interest Exp-Customer Deposits	126,180.82	60350	Interest Exp-Customer Deposits	4,262.09
60359	Interest Exp-Other	1,375,000.00	60359	Interest Exp-Other	108,926.00
61050	Property Taxes-Substations	49,167.09	61050	Property Taxes-Substations	7,705.63
61051	Property Taxes-O/H Lines	941.45	61051	Property Taxes-O/H Lines	0.00
61052	Property Taxes-Buildings	67,628.97	61052	Property Taxes-Buildings	6,833.63
61053	Capital Tax	128,000.00	61053	Capital Tax	0.00
61100	Income Taxes	1,607,995.55	61100	Income Taxes	0.00
63050	Extraordinary Income	0.00	63050	Extraordinary Income	0.00
63100	Extraordinary Deductions	0.00	63100	Extraordinary Deductions	0.00
90190	Inclement Weather	0.00	90190	Inclement Weather	0.00
90200	Unproductive Labour	0.00	90200	Unproductive Labour	0.00
90210	Sfty Mtgs, Line Schl, Seminars	0.00	90210	Sfty Mtgs, Line Schl, Seminars	0.00
90211	Unproductive Labour	0.00	90211	Unproductive Labour	0.00
90220	Small Tool & Equip Purchases	0.00	90220	Small Tool & Equip Purchases	0.00
90230	Clothing	0.00	90230	Clothing	0.00

90240	Meals & Allowances	0.00	90240	Meals & Allowances	0.00
90250	Major Tool & Equip Depr	0.00	90250	Major Tool & Equip Depr	0.00
90260	Tool & Com Equip Mtce	0.00	90260	Tool & Com Equip Mtce	0.00
90270	Tool & Equip Demos & Training	0.00	90270	Tool & Equip Demos & Training	0.00
90280	Tool & Equip Rent & Lease	0.00	90280	Tool & Equip Rent & Lease	0.00
90290	Tool & Equip Exp Allocated	0.00	90290	Tool & Equip Exp Allocated	0.00
90410	Stores-Labour & Expense	0.00	90410	Stores-Labour & Expense	0.00
90420	Stores-Supplies & Expense	0.00	90420	Stores-Supplies & Expense	0.00
90430	Stores-Inventory Adjustment	0.00	90430	Stores-Inventory Adjustment	0.00
90440	Stores-Equipment Mtce	0.00	90440	Stores-Equipment Mtce	0.00
90450	Stores-Building Mtce	0.00	90450	Stores-Building Mtce	0.00
90460	Stores-Equipment Depreciation	0.00	90460	Stores-Equipment Depreciation	0.00
90470	Stores-Variance	0.00	90470	Stores-Variance	0.00
90480	Stores - Minor Material Purch	0.00	90480	Stores - Minor Material Purch	0.00
90490	Stores-Expense Allocated	0.00	90490	Stores-Expense Allocated	0.00
90510	S/C-Furn, Equip & Supplies	0.00	90510	S/C-Furn, Equip & Supplies	0.00
90520	S/C-Bldg Mtce	0.00	90520	S/C-Bldg Mtce	0.00
90530	S/C-Equipment Mtce	0.00	90530	S/C-Equipment Mtce	0.00
90540	S/C-Equipment Rent & Lease	0.00	90540	S/C-Equipment Rent & Lease	0.00
90550	S/C-Property Tax & Insurance	0.00	90550	S/C-Property Tax & Insurance	0.00
90590	S/C-Expense Allocated	0.00	90590	S/C-Expense Allocated	0.00
90610	P/R Burden-Retirees' Benefits	0.00	90610	P/R Burden-Retirees' Benefits	0.00
90710	Rolling Stock-Licences	0.00	90710	Rolling Stock-Licences	0.00
90720	Rolling Stock-Supplies & Exp	0.00	90720	Rolling Stock-Supplies & Exp	0.00
90730	Rolling Stock-Insurance	0.00	90730	Rolling Stock-Insurance	0.00
90740	Rolling Stock-Mtce, Gas & Oil	0.00	90740	Rolling Stock-Mtce, Gas & Oil	0.00
90741	Vehicle Exp Unit # 02	0.00	90741	Vehicle Exp Unit # 02	0.00
90742	Vehicle Exp Unit #10	0.00	90742	Vehicle Exp Unit #10	0.00

90750	Rolling Stock-Building Mtce	0.00	90750	Rolling Stock-Building Mtce	0.00
90760	Rolling Stock-Amortization	0.00	90760	Rolling Stock-Amortization	0.00
90770	Rolling Stock-Property Tax/Ins	0.00	90770	Rolling Stock-Property Tax/Ins	0.00
90790	Rolling Stock-Exp Allocated	0.00	90790	Rolling Stock-Exp Allocated	0.00
90810	Engineering-Lab, Vehicle & Exp	0.00	90810	Engineering-Lab, Vehicle & Exp	0.00
90820	Engineering-Supplies & Expense	0.00	90820	Engineering-Supplies & Expense	0.00
90830	Engineering-Contract Drafting	0.00	90830	Engineering-Contract Drafting	0.00
90840	Engineering-Computer Expenses	0.00	90840	Engineering-Computer Expenses	0.00
90890	Engineering-Expense Allocated	0.00	90890	Engineering-Expense Allocated	0.00
90900	Payroll Burdens	0.00	90900	Payroll Burdens	0.00
90910	P/R Burden - UIC	0.00	90910	P/R Burden - UIC	0.00
90920	P/R Burden - CPP	0.00	90920	P/R Burden - CPP	0.00
90930	P/R Burden - Emp Health Tax	0.00	90930	P/R Burden - Emp Health Tax	0.00
90940	P/P Burden-Pension & Insurance	0.00	90940	P/P Burden-Pension & Insurance	0.00
90941	Employee Future Benefits Exp	0.00	90941	Employee Future Benefits Exp	0.00
90950	PB-Sick Time	0.00	90950	PB-Sick Time	0.00
90951	PB-Vacation	0.00	90951	PB-Vacation	0.00
90952	PB-Stats/Bereave/Personal etc	0.00	90952	PB-Stats/Bereave/Personal etc	0.00
90960	P/R Burden - Workers' Comp	0.00	90960	P/R Burden - Workers' Comp	0.00
90970	P/R Burden - EHC,Dental,Vision	0.00	90970	P/R Burden - EHC,Dental,Vision	0.00
90971	P/R Burden - Future Benefits	0.00	90971	P/R Burden - Future Benefits	0.00
90980	P/R Burden - LT Disability Ins	0.00	90980	P/R Burden - LT Disability Ins	0.00
90990	Payroll Burden Allocated	0.00	90990	Payroll Burden Allocated	0.00
91000	Contributed Capital expense	0.00	91000	Contributed Capital expense	0.00
91010	Contributed Capital Expense	0.00	91010	Contributed Capital Expense	0.00
91200	Contributed Capital Amortized	0.00	91200	Contributed Capital Amortized	0.00
91210	Contributed Capital Amortized	0.00	91210	Contributed Capital Amortized	0.00
91220	Accumulated Contributed	0.00	91220	Accumulated Contributed	0.00

91300	Employee Benefit Liability	0.00
91310	Employee Benefit Expense	0.00
999991	PA O/H re-allocation clearing	0.00
999999	Suspense (System Generated)	0.00

91300	Employee Benefit Liability	0.00
91310	Employee Benefit Expense	0.00
999991	PA O/H re-allocation clearing	0.00
999999	Suspense (System Generated)	0.00

2009

NEWMARKET

Account #	ACC_NAME	YTD Actual
10050	Cash In Bank	3,906,685.85
10051	Payroll Bank Account	0.00
10052	U S Bank Account	22,067.21
10053	U S Exchange	1,125.00
10100	Permanent Cash Advances	0.00
10110	Temporary Cash Advances	0.00
10600	Term Deposits	0.00
10700	Current Investments	2,895,611.00
10701	Current Investments premium	5,870.00
11000	Customer Accounts Receivable	5,449,075.94
11100	Other Accounts Receivable	237,073.72
11101	AR-Municipal St Lt Maintenance	64,713.00
11102	AR-Billing Adjustments	-0.02
11103	AR-Customer Time Payments	0.00
11104	AR-Recoverable Work	14,775.52
11105	AR- OMERS Overpayment	0.00
11106	AR-Accounts to Clo Agent	0.00
11107	Suspense	-3,016.55
11108	Consumer Deposits Suspense	0.00
11109	Accounts Receivable Suspense	0.00
11110	Letters of Credit Suspense	0.00
11111	AR-Municipal St Lt Capital	0.00
11112	AR-NHHI	-1,779,566.00
11113	1443393 Ontario Inc.	126,104.64
11114	Retirements	0.00

TAY

Account #	ACC_NAME	YTD Actual
10050	Cash In Bank	427,744.17
10051	Payroll Bank Account	0.00
10052	U S Bank Account	0.00
10053	U S Exchange	0.00
10100	Permanent Cash Advances	0.00
10110	Temporary Cash Advances	0.00
10600	Term Deposits	0.00
10700	Current Investments	0.00
10701	Current Investments premium	0.00
11000	Customer Accounts Receivable	423,151.91
11100	Other Accounts Receivable	41,243.99
11101	AR-Municipal St Lt Maintenance	1,457.37
11102	AR-Billing Adjustments	0.00
11103	AR-Customer Time Payments	0.00
11104	AR-Recoverable Work	0.00
11105	AR- OMERS Overpayment	0.00
11106	AR-Accounts to Clo Agent	0.00
11107	Suspense	0.00
11108	Consumer Deposits Suspense	0.00
11109	Accounts Receivable Suspense	0.00
11110	Letters of Credit Suspense	0.00
11111	AR-Municipal St Lt Capital	0.00
11112	AR-NHHI	0.00
11113	1443393 Ontario Inc.	0.00
11114	2006 EDR Receivable	36,874.87

11200	Unbilled Revenue	8,746,323.08
11300	Allowance for Doubtful Acct	-309,695.14
11700	Notes Receivable	0.00
11800	Prepaid Expense	329,789.00
11801	Leased Vehicles	0.00
11802	Upper Canada Energy Alliance	-1,372.39
11803	Prepaid Expense- ERA	313,383.87
11900	Other Current Assets	1,822.84
13300	Inventory	871,905.56
13301	Inventory-Suspense	0.00
13302	Inventory-Default	-107,000.28
13400	Inventory - Water St Retail	0.00
14600	Long Term Rec-Billing Adj	0.00
14601	LT Rec - OMERS Overpayment	0.00
14602	LT Rec - Cust Time Payment	0.00
15080	Other Regulatory Assets	0.00
15087	Other Regulatory Assets - CC	0.00
15180	Retail Cost Variance - Retail	254.96
15187	Retail Cost Var - Retail CC	2.23
15250	Misc Deferred Debits	0.00
15251	Misc Deferred Debits - CC	0.00
15252	Deferred Charges-Amortization	0.00
15253	UCEA Inc	0.00
15254	Deferred Charges-Recovery	0.00
15480	Retail Cost Variance - STR	7,989.76
15487	Retail Cost Variance - STR-CC	28.04
15500	Low Voltage Variance - Revenue	0.00
15501	Low Voltage Variance - Costs	0.00

11200	Unbilled Revenue	779,742.03
11300	Allowance for Doubtful Acct	-46,239.46
11700	Notes Receivable	0.00
11800	Prepaid Expense	42,918.62
11801	Leased Vehicles	0.00
11802	Upper Canada Energy Alliance	0.00
11803	Prepaid Expense- ERA	1,120.87
11900	Other Current Assets	1,247.20
13300	Inventory	80,902.49
13301	Inventory-Suspense	-4,090.85
13302	Inventory-Default	0.00
13400	Inventory - Water St Retail	0.00
14600	Long Term Rec-Billing Adj	0.00
14601	LT Rec - OMERS Overpayment	0.00
14602	LT Rec - Cust Time Payment	0.00
15080	Other Regulatory Assets	45,024.85
15087	Other Regulatory Assets - CC	6,793.71
15180	Retail Cost Variance - Retail	-942.83
15187	Retail Cost Var - Retail CC	-113.69
15250	Misc Deferred Debits	2,173.50
15251	Misc Deferred Debits - CC	177.49
15252	Deferred Charges-Amortization	0.00
15253	UCEA Inc	0.00
15254	Deferred Charges-Recovery	0.00
15480	Retail Cost Variance - STR	1,280.33
15487	Retail Cost Variance - STR-CC	108.15
15500	Low Voltage Variance - Revenue	-209,785.10
15501	Low Voltage Variance - Costs	180,504.26

15502	LV METERING CHARGE	0.00	15502	LV METERING CHARGE	12,119.90
15503	LV METERING MNTHLY CHARGE	0.00	15503	LV METERING MNTHLY CHARGE	4,139.87
15507	Low Voltage Variance - CC	0.00	15507	Low Voltage Variance - CC	154.04
15550	Smart Meter Capital Expenditur	0.00	15550	Smart Meter Capital Expenditur	0.00
15551	Smart Meter Cap/Rec Offset Var	0.00	15551	Smart Meter Cap/Rec Offset Var	-325,207.24
15560	Smart Meter - OM&A	185,666.00	15560	Smart Meter - OM&A	25,764.31
15561	Smart Meter - OM&A Revenue	0.00	15561	Smart Meter - OM&A Revenue	0.00
15567	Smart Meter - OM&A CC	62.86	15567	Smart Meter - OM&A CC	2,273.03
15620	Deferred PILS	135,170.64	15620	Deferred PILS	123,821.40
15627	Deferred PILS - CC	171,840.11	15627	Deferred PILS - CC	12,529.02
15630	Deferred PILS Contra	-135,170.64	15630	Deferred PILS Contra	-123,821.40
15637	Deferred PILS Contra CC	-171,840.11	15637	Deferred PILS Contra CC	-12,529.02
15650	Conserve & Demand Revenue	-1,267,000.00	15650	Conservation&Demand Management	0.00
15651	Gateway Project	0.00	15651	Gateway Project	0.00
15652	Residential	354,829.52	15652	Residential	-257.48
15653	Affordable/Social Housing	385,116.25	15653	Affordable/Social Housing	0.00
15654	Small Business	0.00	15654	Small Business	0.00
15655	Business/Commerical/Industrial	79,886.43	15655	Business/Commerical/Industrial	0.00
15656	Education Program	158,611.00	15656	Education Program	11,369.13
15657	Other Programs/Discretionary	98,773.07	15657	Other Programs/Discretionary	30,917.55
15658	Distributions System studies	0.00	15658	Distributions System studies	3,874.53
15659	Program Develop & Monitoring	141,801.08	15659	Program Develop & Monitoring	3,612.98
15660	C&DM Recovered From Customers	0.00	15660	C&DM Recovered From Customers	-41,808.83
15700	Transition Costs	0.00	15700	Transition Costs	0.00
15701	Transition Costs - Recovery	0.00	15701	Transition Costs - Recovery	0.00
15707	Transition Costs - CC	0.00	15707	Transition Costs - CC	0.00
15710	Pre Market Energy	0.00	15710	Pre Market Energy	0.00
15711	Pre Market Energy-Residential	0.00	15711	Pre Market Energy-Residential	0.00

15712	Pre Market Energy-GS LT 50	0.00	15712	Pre Market Energy-GS LT 50	0.00
15713	Pre Market Energy-GS GT 50 kW	0.00	15713	Pre Market Energy-GS GT 50 kW	0.00
15714	Pre Market Energy-GS GT 50 kWh	0.00	15714	Pre Market Energy-GS GT 50 kWh	0.00
15715	Pre Market Energy-Street Light	0.00	15715	Pre Market Energy-Street Light	0.00
15716	Pre Market Energy-Sentinel Lts	0.00	15716	Pre Market Energy-Sentinel Lts	0.00
15718	Pre Market - Variance Recovery	0.00	15718	Pre Market - Variance Recovery	0.00
15800	RSVA-Whlsle Market Serv Rev	-4,171,079.91	15800	RSVA-Whlsle Market Serv Rev	-1,417,204.12
15801	RSVA-Whlsle Market Serv Chg	4,394,376.52	15801	RSVA-Whlsle Market Serv Chg	1,451,010.50
15802	RSVA-WMS Fixed Chg Settltment	0.00	15802	RSVA-WMS Fixed Chg Settltment	0.00
15807	RSVA-WMS CC	-361.87	15807	RSVA-WMS CC	1,645.95
15808	RSVA-WMS - Recovery	0.00	15808	RSVA-WMS - Recovery	0.00
15809	RSVA-WMS Unbilled	-584,580.13	15809	RSVA-WMS Unbilled	-44,852.33
15820	RSVA-One Time Charges-Revenue	0.00	15820	RSVA-One Time Charges-Revenue	0.00
15821	RSVA-One Time Charges-Charges	25,845.16	15821	RSVA-One Time Charges-Charges	-2,427.88
15827	RSVA-One Time Charges-CC	65.74	15827	RSVA-One Time Charges-CC	-340.24
15840	RSVA-Trans Network Revenue	-3,205,217.95	15840	RSVA-Trans Network Revenue	-1,202,633.30
15841	RSVA-Trans Network Charges	3,629,142.74	15841	RSVA-Trans Network Charges	1,088,944.91
15842	RSVA-Trans Meter Credit	0.00	15842	RSVA-Trans Meter Credit	0.00
15847	RSVA - Trans Network CC	280.88	15847	RSVA - Trans Network CC	-5,236.88
15848	RSVA-Trans Network Recovery	0.00	15848	RSVA-Trans Network Recovery	0.00
15849	RSVA - Trans Network Unbilled	0.00	15849	RSVA - Trans Network Unbilled	-37,032.57
15860	RSVA-Trans Connection Revenue	-2,897,625.21	15860	RSVA-Trans Connection Revenue	-1,056,012.22
15861	RSVA-Trans Connection Charges	3,246,363.92	15861	RSVA-Trans Connection Charges	768,912.91
15867	RSVA-Trans Connection CC	31.92	15867	RSVA-Trans Connection CC	-66,034.18
15868	RSVA-Trans Connection Recovery	0.00	15868	RSVA-Trans Connection Recovery	0.00
15869	RSVA-Trans Unbilled	-852,678.28	15869	RSVA-Trans Unbilled	-32,676.27
15880	RSVA-Power Pd By Customers	-11,363,653.27	15880	RSVA-Power Pd By Customers	-1,195,628.38
15881	RSVA-Power Purchased IESO	24,139,088.92	15881	RSVA-Power Purchased IESO	11,534,307.48

15882	Spot Price Pd By Customers	-10,828,217.29	15882	Spot Price Pd By Customers	-5,049,356.57
15883	Fixed Price Pd By Customers	-10,303,370.95	15883	Fixed Price Pd By Customers	-8,914,723.92
15884	Fixed Price Variance Account	10,924,258.40	15884	Fixed Price Variance Account	4,552,144.59
15885	Fixed Price IMO Settlement	0.00	15885	Fixed Price IMO Settlement	0.00
15886	Fixed Price Time of Use Rates	-8,789,516.40	15886	Fixed Price Time of Use Rates	-1,770,858.55
15887	RSVA - Power - CC	5,202.24	15887	RSVA - Power - CC	26,076.39
15888	RSVA - Energy Recovery	0.00	15888	RSVA - Energy Recovery	0.00
15889	RSVA-Power Unbilled	-5,368,625.32	15889	RSVA-Power Unbilled	-413,885.14
15890	Pre-Market & RSVA Clearing	0.00	15890	Pre-Market & RSVA Clearing	0.00
15900	Approved Reg Assets	0.00	15900	Approved Reg Assets	716,661.00
15901	Approved Reg Assets - Recovery	-536,854.91	15901	Approved Reg Assets - Recovery	-1,096,095.29
15907	Approved Reg Assets CC	8,782.56	15907	Approved Reg Assets CC	9,360.91
15950	Approved Deferral Balance-2008	1,401,650.61	15950	Approved Deferral Balance-2008	0.00
15951	APPROVED DEFERRALRECOVERY2008	-574,764.59	15951	APPROVED DEFERRALRECOVERY2008	0.00
15952	APPROVED SM RECOVERY-2008	39,136.90	15952	APPROVED SM RECOVERY-2008	0.00
15956	Approved CC to be Recovered-08	234,207.56	15956	Approved CC to be Recovered-08	0.00
15957	Approved Deferral CC-2008	4,371.81	15957	Approved Deferral CC-2008	0.00
15959	Unbilled Deferral & Smart M.	-142,787.97	15959	Unbilled Deferral & Smart M.	0.00
15990	Regulated Price Plan Settlemen	-1,408,646.23	15990	Regulated Price Plan Settlemen	-233,282.53
15991	Reg Price Plan retailer settl	715,493.93	15991	Reg Price Plan retailer settl	183,367.45
15993	Global Adj - CC	0.00	15993	Global Adj - CC	651.71
15994	Global Adj Payabe re lRPP	0.00	15994	Global Adj Payabe re lRPP	0.00
15995	Global adjustment	-8,802,690.91	15995	Global adjustment	-273,369.67
15996	Global Adj Settlement Amount	21,019,776.61	15996	Global Adj Settlement Amount	1,616,711.51
15997	RPP Adj Settlement Amount	66,102.17	15997	RPP Adj Settlement Amount	-35,426.27
16060	Organization Costs	0.00	16060	Organization Costs	27,610.98
18050	Distribution-Land	3,070,162.31	18050	Distribution-Land	58,066.87
18060	Distribution-Land Rights	348,064.99	18060	Distribution-Land Rights	241,736.72

18200	Dist Stn-Rec Complex	77,383.00	18200	Dist Stn-Rec Complex	0.00
18201	Dist Stn-Legge	656,912.16	18201	Dist Stn-Legge	0.00
18202	Dist Stn-Thompson	994,658.54	18202	Dist Stn-Thompson	0.00
18203	Dist Stn-Broughton/Simmons	1,062,864.26	18203	Dist Stn-Broughton/Simmons	0.00
18204	Dist Stn-Gilbert	1,136,841.73	18204	Dist Stn-Gilbert	0.00
18205	Dist Stn-Andrews	1,113,931.67	18205	Dist Stn-Andrews	0.00
18206	Dist Stn-Leadbeater	688,704.98	18206	Dist Stn-Leadbeater	0.00
18207	Dist Stn-Cook	504,800.39	18207	Dist Stn-Cook	0.00
18208	Dist Stn-Twinney	1,262,582.97	18208	Dist Stn-Twinney	0.00
18209	Dist Stn-S/E Quadrant	559,816.98	18209	Dist Stn-S/E Quadrant	0.00
18210	Dist Stn-Miscellaneous	22,320.21	18210	Dist Stn-Miscellaneous	0.00
18211	Dist Stn Port McNicholl	0.00	18211	Dist Stn Port McNicholl	108,852.49
18212	Dist Stn Victoria Harbour	0.00	18212	Dist Stn Victoria Harbour	288,429.95
18213	Dist Stn Waubaushene	0.00	18213	Dist Stn Waubaushene	98,161.72
18214	Port McNicholl MS 2	0.00	18214	Port McNicholl MS 2	380,680.32
18300	Dist Lines O/H Poles	13,180,233.09	18300	Dist Lines O/H Poles	1,724,320.50
18301	Inventory Holding - O/H Poles	0.00	18301	Inventory Holding - O/H Poles	13,403.88
18350	Dist Lines O/H Conductor	15,414,035.00	18350	Dist Lines O/H Conductor	1,618,138.97
18351	Invent. Holding- O/H Conductor	0.00	18351	Invent. Holding- O/H Conductor	2,066.60
18400	Dist Lines U/G Conduit	8,365,725.46	18400	Dist Lines U/G Conduit	71,087.02
18401	Inventory Holding-U/G Conduit	0.00	18401	Inventory Holding-U/G Conduit	0.00
18450	Dist Lines U/G Conductor	24,928,039.17	18450	Dist Lines U/G Conductor	422,286.93
18451	Invent. Holding-U/G Conductor	0.00	18451	Invent. Holding-U/G Conductor	0.00
18500	Distribution Transformers	16,158,718.86	18500	Distribution Transformers	1,109,710.38
18501	Invent. Holding-Transformers	0.00	18501	Invent. Holding-Transformers	0.00
18550	Services	6,504,448.86	18550	Services	1,303,055.61
18551	44 KV CAPITAL STUDY	6,530.26	18551	44 KV CAPITAL STUDY	0.00
18552	13.8 KV CAPITAL STUDY	2,517.15	18552	13.8 KV CAPITAL STUDY	0.00

18600	Distribution Meters	4,547,259.01	18600	Distribution Meters	31,047.66
18610	Smart Meters	4,734,027.53	18610	Smart Meters	610,276.93
18650	Wholesale Meters	933,208.61	18650	Wholesale Meters	0.00
18750	Distribution Street Lights	0.00	18750	Distribution Street Lights	0.00
18990	Capital Asset Management	14,607.54	18990	Capital Asset Management	0.00
189999	Capital Holding Account	0.00	189999	Capital Holding Account	0.00
19050	General Plant - Land	89.70	19050	General Plant - Land	0.00
19080	Buildings-Eagle Street	0.00	19080	Buildings-Eagle Street	297,911.58
19081	Leasehold Imp-Steven Court	710,826.12	19081	Leasehold Imp-Steven Court	0.00
19082	Buildings-Water Street	0.00	19082	Buildings-Water Street	0.00
19083	Buildings-Other	0.00	19083	Buildings-Other	0.00
19150	Office Equipment	303,475.40	19150	Office Equipment	67,514.87
19200	Computer Hardware	748,704.36	19200	Computer Hardware	116,028.62
19250	Computer Software	1,216,321.64	19250	Computer Software	287,475.75
19300	Transportation Equipment	4,014,755.54	19300	Transportation Equipment	203,432.00
19350	Stores Equipment	144,862.67	19350	Stores Equipment	6,384.82
19400	Tools, Shop & Garage Equipment	465,031.58	19400	Tools, Shop & Garage Equipment	65,721.78
19450	Measurement & Testing Equip	102,535.07	19450	Measurement & Testing Equip	0.00
19650	Water Heater Rental units	0.00	19650	Water Heater Rental units	0.00
19800	System Supervisory Equipment	731,769.42	19800	System Supervisory Equipment	0.00
19810	System Optimization Study	10,871.57	19810	System Optimization Study	0.00
19850	Sentinel Light Rental Units	13,085.27	19850	Sentinel Light Rental Units	9,966.47
19900	Amalco Capital	0.00	19900	Amalco Capital	0.00
19950	Cont Cap to be Amortized	-17,488,176.09	19950	Cont Cap to be Amortized	-466,425.82
199999	Fixed Assets Suspense	0.00	199999	Fixed Assets Suspense	0.00
20550	Construction In Progress	0.00	20550	Construction In Progress	0.00
21050	Accum Dep-Current Provision	0.00	21050	Accum Dep-Current Provision	0.00
21051	Accum Amor-Organization Costs	0.00	21051	Accum Amor-Organization Costs	-27,610.98

21052	Accum Amor-Buildings Other	0.00	21052	Accum Amor-Buildings Other	-92,288.14
21053	Accum Amor-Stations	-4,517,084.87	21053	Accum Amor-Stations	-315,204.05
21054	Accum Amor-O/H Lines	-14,199,792.93	21054	Accum Amor-O/H Lines	-2,206,593.79
21055	Accum Amor-Land Rights	-13,144.90	21055	Accum Amor-Land Rights	-117,354.40
21056	Accum Amor-U/G Lines	-18,108,196.49	21056	Accum Amor-U/G Lines	-947,720.19
21057	Accum Amor-Transformers	-7,946,387.81	21057	Accum Amor-Transformers	-681,005.86
21058	Accum Amor-Meters	-3,323,082.67	21058	Accum Amor-Meters	-142,386.72
21059	Accum Amor-Street Lights	0.00	21059	Accum Amor-Street Lights	0.00
21060	Accum Amor-Office Equipment	-196,922.51	21060	Accum Amor-Office Equipment	-51,085.49
21061	Accum Amor-Computer Equipment	-591,115.16	21061	Accum Amor-Computer Equipment	-71,832.02
21062	Accum Amor-Computer Software	-1,052,237.05	21062	Accum Amor-Computer Software	-211,282.21
21063	Accum Amor-Stores Equipment	-110,206.27	21063	Accum Amor-Stores Equipment	-6,384.82
21064	Accum Amor-Transportation Equi	-2,694,524.57	21064	Accum Amor-Transportation Equi	-192,971.52
21065	Accum Amor-Tools	-409,053.13	21065	Accum Amor-Tools	-48,322.91
21066	Accum Amor-Water Heaters	0.00	21066	Accum Amor-Water Heaters	0.00
21067	Accum Amor-Leasehold	-415,979.96	21067	Accum Amor-Leasehold	0.00
21068	Accum Amor-System Supervisory	-563,910.28	21068	Accum Amor-System Supervisory	0.00
21069	Accum Amor-Sentinel Lights	-13,085.74	21069	Accum Amor-Sentinel Lights	-9,966.47
21070	Accum Amor-Street Lights	0.00	21070	Accum Amor-Street Lights	0.00
21090	Accum Amor-Cont Cap	3,825,007.64	21090	Accum Amor-Cont Cap	63,567.25
22050	Accounts Payable	-973,014.18	22050	Accounts Payable	-383,217.82
22051	A/P-Town Water Billing	-1,107,151.34	22051	A/P-Town Water Billing	0.00
22052	A/P-Power Bill	-4,709,951.35	22052	A/P-Power Bill	0.00
22053	A/P-Income Tax	-19,999.66	22053	A/P-Income Tax	0.00
22054	Miscellaneous Accruals	-560,772.25	22054	Miscellaneous Accruals	-352,161.03
22055	A/P-MPMA Rebate	-74,297.59	22055	A/P-MPMA Rebate	2,232.48
22056	A/P-Phase 2 Rebate	0.00	22056	A/P-Phase 2 Rebate	0.00
22057	A/P-$75 Rebate	0.00	22057	A/P-$75 Rebate	0.00

22058	Accounts Payable-Default	0.00	22058	Accounts Payable-Default	0.00
22059	A/P-Town Other	0.12	22059	A/P-Town Other	0.00
22060	Invoice Settlement-Direct	0.00	22060	Invoice Settlement-Direct	-37.94
22061	BRC - Toronto Hydro	0.00	22061	BRC - Toronto Hydro	0.00
22062	BRC - OPG	0.00	22062	BRC - OPG	0.00
22063	BRC - Ontario Hydro	0.00	22063	BRC - Ontario Hydro	0.00
22064	BRC - First Source	0.00	22064	BRC - First Source	0.00
22065	BRC - Ontario Electric Savings	0.00	22065	BRC - Ontario Electric Savings	0.00
22066	BRC - Coral Energy	0.00	22066	BRC - Coral Energy	0.00
22067	BRC - Canadian Choice Energy	0.00	22067	BRC - Canadian Choice Energy	0.00
22068	BRC - Constellation New Energy	0.00	22068	BRC - Constellation New Energy	0.00
22069	BRC - Universal Energy	0.00	22069	BRC - Universal Energy	0.00
22070	BRC - ECNG	0.00	22070	BRC - ECNG	0.00
22071	BRC -Canadian Hydro	0.00	22071	BRC -Canadian Hydro	0.00
22072	BRC - Bullfrog Power	0.00	22072	BRC - Bullfrog Power	0.00
22073	BRC - SEMINC	0.00	22073	BRC - SEMINC	0.00
22074	BRC - Superior Energy	0.00	22074	BRC - Superior Energy	0.00
22075	BRC - Wholesale Energy	0.00	22075	BRC - Wholesale Energy	0.00
22076	BRC - Planet Energy Ontario Co	0.00	22076	BRC - Planet Energy Ontario Co	0.00
22077	BRC - AG ENERGY CO-OP LTD	0.00	22077	BRC - AG ENERGY CO-OP LTD	0.00
22078	BRC - National Energy Corp.	0.00	22078	BRC - National Energy Corp.	0.00
22080	Customer Credit Balances	-1,324,579.30	22080	Customer Credit Balances	-88,851.58
22100	Customer Deposits-Current	-300,000.00	22100	Customer Deposits-Current	-25,000.00
22200	Unused Vacation Pay Accrual	-63,583.32	22200	Unused Vacation Pay Accrual	-8,028.89
22201	Payroll Clearing	-58,176.88	22201	Payroll Clearing	613.88
222011	Interco due to & due from	372,516.62	222011	Interco due to & due from	-371,871.07
22202	Subdivider Lot Levies-Current	-52,586.00	22202	Subdivider Lot Levies-Current	0.00
22250	Other Current Liabilities	0.00	22250	Other Current Liabilities	-609.33

22251	Notes and Loans Payable	0.00
22500	Debt Retirement Charges	0.00
22560	AP - IMO	0.00
22600	Current Portion Long Term Debt	0.00
22601	Current Portion Other Debt	0.00
22640	OPA - Refrigerator Roundup	-16,895.67
22641	OPA - Summer Savings	0.00
22642	OPA - Peaksaver	-0.20
226421	OPA - ERIP	0.00
226422	OPA-Direct Installs	-21,544.56
226423	OPA-Comm Initiative Fund	-37,841.53
226424	OPA - MEER	-3,087.55
22643	Thermostats - Barrie	0.00
22644	Thermostats - Innisfil	0.00
22645	Thermostats -Essex	0.00
22646	Thermostats -Enwin	0.00
22647	Thermostats -Erie Thames	0.00
22648	Thermostats -St Thomas	0.00
22649	Thermostats -Clinton	0.00
22650	Thermostats -West Perth	0.00
22680	Accrued Interest-L T Debt	0.00
22681	Accrued Interest-Cust Deps	-11,878.81
22901	GST - ITC 100%	254,142.08
22902	GST - ITC 57.14% St Lts	0.00
22903	GST - ITC 50%	12.55
22904	GST - Collected	-316,049.11
22905	GST - Remittance	0.00
22909	PST Payable	0.00

22251	Notes and Loans Payable	-4,680.82
22500	Debt Retirement Charges	0.00
22560	AP - IMO	0.00
22600	Current Portion Long Term Debt	0.00
22601	Current Portion Other Debt	0.00
22640	CSB's Emp Installment Plan	0.00
22641	OPA - Summer Savings	0.00
22642	OPA - Peaksaver	0.00
226421	OPA - ERIP	0.00
226422	OPA-Direct Installs	0.00
226423	OPA-Comm Initiative Fund	0.00
226424	OPA - MEER	0.00
22643	Thermostats - Barrie	0.00
22644	Thermostats - Innisfil	0.00
22645	Thermostats -Essex	0.00
22646	Thermostats -Enwin	0.00
22647	Thermostats -Erie Thames	0.00
22648	Thermostats -St Thomas	0.00
22649	Thermostats -Clinton	0.00
22650	Thermostats -West Perth	0.00
22680	Accrued Interest-L T Debt	0.00
22681	Accrued Interest-Cust Deps	-2,752.25
22901	GST - ITC 100%	18,389.23
22902	GST - ITC 57.14% St Lts	0.00
22903	GST - ITC 50%	0.00
22904	GST - Collected	-26,477.31
22905	GST - Remittance	0.00
22909	PST Payable	0.00

22921	Income Tax Payable	595.53	22921	Income Tax Payable	0.00
22922	CPP Payable	260.72	22922	CPP Payable	0.00
22923	Employment Insurance Payable	0.00	22923	Employment Insurance Payable	0.00
22924	OMERS Payable	-164.47	22924	OMERS Payable	0.00
22925	EHT Payable	-5,480.46	22925	EHT Payable	0.00
22926	W.S.I.B. Payable	-1,226.75	22926	W.S.I.B. Payable	0.00
22927	Life Insurance Payable	59.74	22927	Life Insurance Payable	0.00
22928	Garnishee Payable	0.00	22928	Garnishee Payable	0.00
22929	Union Dues	0.00	22929	Union Dues	0.00
229291	RRSP Payable	0.00	229291	RRSP Payable	0.00
23060	Employee Future Benefits	-880,015.00	23060	Employee Future Benefits	-58,034.00
23200	Other Non-Current Liabilities	0.00	23200	Other Non-Current Liabilities	0.00
23201	Deferred Credits	-47,514.40	23201	Deferred Credits	0.00
23300	Subdividers Lot Levies	0.00	23300	Subdividers Lot Levies	0.00
23301	Lot Levies-Single Units	0.00	23301	Lot Levies-Single Units	0.00
23350	Customer Deposits	-2,932,326.46	23350	Customer Deposits	-133,275.31
23351	Construction Deposits	-766,629.80	23351	Construction Deposits	0.00
23352	Retailer Deposits	0.00	23352	Retailer Deposits	0.00
23353	Consumer Deposit Suspense	-7,810.00	23353	Consumer Deposit Suspense	0.00
24050	Other Regulatory Liabilities	0.00	24050	Other Regulatory Liabilities	-33,121.86
25000	Long Term Debt	0.00	25000	Long Term Debt	0.00
25200	Long Term Debt - Town	-22,000,000.00	25200	Long Term Debt - Town	-1,742,821.00
30220	Lot Levies Transf'd to Equity	-201,720.00	30220	Lot Levies Transf'd to Equity	0.00
30300	Contributed Capital-Equity	-33,468,574.15	30300	Contributed Capital-Equity	-1,742,821.00
30301	Contributed Capital-St Lts	0.00	30301	Contributed Capital-St Lts	0.00
30450	Accumulated Net Income	-4,051,735.16	30450	Accumulated Net Income	31,093.41
30451	Dividends Paid	3,788,000.00	30451	Dividends Paid	565,000.00
30490	Dividends Declared	4,410,000.00	30490	Dividends Declared	0.00

40060	Energy-Residential	-229.54
40061	Residential-Dist Customer Chg	-4,003,252.53
40062	Residential-Dist kWh	-3,297,127.30
40063	Residential-Energy kWh	0.00
40064	Residential-Retro Adjustment	0.00
40068	Energy-Res-PILS Trans Recovery	193,112.13
40250	Energy-Street Lights	-1,394.47
40251	Energy-Sentinel Lights	0.00
40252	Street Light-Dist kW Charge	-79,419.32
40253	Street Light-Energy kW Charge	0.00
40254	Street Light-Retro Adj	0.00
40255	Street Light-Dist Fixed Chg	-103,217.12
40258	St Light-PIL Trans Recovery	1,886.88
40302	Sentinel Light Distribution kW	-4,497.70
40303	Sentinel Light Energy kW	0.00
40305	Sentinel Light Service Charge	-8,561.82
40308	Sent Lt PILS Trans Recovery	164.77
40350	GT 50 - Dist Electric Meter Ad	0.00
40351	GS LT 50-Dist Cust Chg	-762,393.23
40352	GS LT 50-Dist kWh Charge	-1,497,843.91
40353	GS LT 50-Energy kWh Charge	0.00
40354	GS LT 50-PIL Trans Recovery	71,833.50
40355	GS GT 50-Dist Cust Charge	-1,153,090.31
40356	GS GT 50-Dist kW Charge	-2,938,847.18
40357	GS GT 50-Energy kW Charge	0.00
40358	GS GT 50-PIL Trans Recovery	270,092.23
40359	GS GT 50-Retro Adj	0.00
40360	C&DM Recovered From Customers	0.00

40060	Energy-Residential	0.00
40061	Residential-Dist Customer Chg	-786,586.74
40062	Residential-Dist kWh	-551,037.64
40063	Residential-Energy kWh	0.00
40064	Residential-Retro Adjustment	0.00
40068	Energy-Res-PILS Trans Recovery	353,363.67
40250	Energy-Street Lights	0.00
40251	Energy-Sentinel Lights	0.00
40252	Street Light-Dist kW Charge	-5,404.77
40253	Street Light-Energy kW Charge	0.00
40254	Street Light-Retro Adj	0.00
40255	Street Light-Dist Fixed Chg	-5,423.79
40258	St Light-PIL Trans Recovery	1,811.25
40302	Sentinel Light Distribution kW	-269.04
40303	Sentinel Light Energy kW	0.00
40305	Sentinel Light Service Charge	-139.44
40308	Sent Lt PILS Trans Recovery	206.19
40350	GT 50 - Dist Electric Meter Ad	-354.00
40351	GS LT 50-Dist Cust Chg	-49,677.07
40352	GS LT 50-Dist kWh Charge	-107,651.22
40353	GS LT 50-Energy kWh Charge	0.00
40354	GS LT 50-PIL Trans Recovery	34,954.78
40355	GS GT 50-Dist Cust Charge	-27,245.88
40356	GS GT 50-Dist kW Charge	-63,327.02
40357	GS GT 50-Energy kW Charge	0.00
40358	GS GT 50-PIL Trans Recovery	20,563.81
40359	GS GT 50-Retro Adj	0.00
40360	C&DM Recovered From Customers	0.00

40500	Energy-Adjustments	-227,360.18
40550	Smart Meter Revenue Rec'd	0.00
40551	WAP/R - Direct	0.00
40552	WAP/GS - Direct	0.00
40553	WAP/R - THESI	0.00
40554	WAP/GS - THESI	0.00
40555	WAP/R - OPG	0.00
40556	WAP/GS - OPG	0.00
40557	WAP/R - OHE	0.00
40558	WAP/GS - OHE	0.00
40559	WAP/R - First Source	0.00
40560	WAP/GS - First Source	0.00
40561	WAP/R - Coral Energy	0.00
40562	WAP/GS - Coral Energy	0.00
40563	WAP/R - OESC	0.00
40564	WAP/GS - OESC	0.00
40565	WAP/R - Cdn Choice	0.00
40566	WAP/GS - Cdn Choice	0.00
40620	Whlsl Mrkt Services Billed	0.00
40640	Whlsl Mrkt Srvcs Blld 1 time	0.00
40660	Retail Transmission Service	0.00
40680	Retail Transmission Connection	0.00
40800	SSS Administration Charge	-95,796.49
40801	Distribution Wheeling Service	0.00
40802	Recver Reg Assets prev W/O	0.00
40820	Retail Service Revenues	-41,972.00
40840	STR Revenues	-617.75
42103	Revenue-Pole Rentals	-63,224.37

40500	Energy-Adjustments	-14,795.06
40550	Smart Meter Revenue Rec'd	0.00
40551	WAP/R - Direct	0.00
40552	WAP/GS - Direct	0.00
40553	WAP/R - THESI	0.00
40554	WAP/GS - THESI	0.00
40555	WAP/R - OPG	0.00
40556	WAP/GS - OPG	0.00
40557	WAP/R - OHE	0.00
40558	WAP/GS - OHE	0.00
40559	WAP/R - First Source	0.00
40560	WAP/GS - First Source	0.00
40561	WAP/R - Coral Energy	0.00
40562	WAP/GS - Coral Energy	0.00
40563	WAP/R - OESC	0.00
40564	WAP/GS - OESC	0.00
40565	WAP/R - Cdn Choice	0.00
40566	WAP/GS - Cdn Choice	0.00
40620	Whlsl Mrkt Services Billed	0.00
40640	Whlsl Mrkt Srvcs Blld 1 time	0.00
40660	Retail Transmission Service	0.00
40680	Retail Transmission Connection	0.00
40800	SSS Administration Charge	-12,201.85
40801	Distribution Wheeling Service	0.00
40802	Recver Reg Assets prev W/O	0.00
40820	Retail Service Revenues	-5,113.20
40840	STR Revenues	-3,631.25
42103	Revenue-Pole Rentals	-61,002.51

42250	Revenue-Late Payment Charges	-190,346.68
42350	Revenue-St LT Non-Energy	0.00
42351	Account Setup	-53,050.00
42352	Revenue-Reconnection Charges	-23,780.00
42353	Revenue-Collection Charges	-147,701.22
42354	Change of Occupancy-Final Bill	-42,025.00
43102	Revenue-Sentinel Lt Rentals	-20,761.80
43250	Revenue-Sale of Scrap Metals	-11,489.64
43251	Water St-Mark Up on Sales	0.00
43550	Gain on Sale of Assets	0.00
43600	Loss on Sale of Assets	0.00
43850	Non-Utility Rental Income	-2,186.62
43851	Water Heater Rental Income	0.00
43900	Revenue-Miscellaneous	0.00
43901	Revenue-Profit on Mat & Serv	-4,560.97
43902	Revenue-Arrears Certificates	-1,596.00
43903	Revenue-Power Bill Aggregation	0.00
43904	Costs re By-passed Meters	0.00
43905	Revenue re By-passed Meters	-59.50
44050	Interest Earned	-50,966.83
44051	CC on Reg Assets	-15,425.57
47050	Pre Market & RSVA Clearing	0.00
47051	Transition Cost Write Off	0.00
47080	Power Purchased - WMS	0.00
47100	Power Purchased-Adjustments	0.00
47120	Power Purchased - On Time	0.00
47140	Power Purchased - Network	0.00
47160	Power Purchased - Connection	0.00

42250	Revenue-Late Payment Charges	-24,191.25
42350	Revenue-St LT Non-Energy	0.00
42351	Account Setup	-7,410.00
42352	Revenue-Reconnection Charges	-6,785.00
42353	Revenue-Collection Charges	-36,615.00
42354	Change of Occupancy-Final Bill	0.00
43102	Revenue-Sentinel Lt Rentals	-1,357.80
43250	Revenue-Sale of Scrap Metals	0.00
43251	Water St-Mark Up on Sales	0.00
43550	Gain on Sale of Assets	0.00
43600	Loss on Sale of Assets	994.92
43850	Non-Utility Rental Income	0.00
43851	Water Heater Rental Income	0.00
43900	Revenue-Miscellaneous	-7,994.21
43901	Revenue-Profit on Mat & Serv	-1,041.33
43902	Revenue-Arrears Certificates	-45.00
43903	Revenue-Power Bill Aggregation	0.00
43904	Costs re By-passed Meters	0.00
43905	Revenue re By-passed Meters	0.00
44050	Interest Earned	-3,594.23
44051	CC on Reg Assets	-18,660.15
47050	Pre Market & RSVA Clearing	0.00
47051	Transition Cost Write Off	0.00
47080	Power Purchased - WMS	0.00
47100	Power Purchased-Adjustments	0.00
47120	Power Purchased - On Time	0.00
47140	Power Purchased - Network	0.00
47160	Power Purchased - Connection	0.00

47250	Competition Transition Charges	0.00
50050	Operation Supervision	71,300.66
50160	Substn Op'n-Labour	20,637.71
50161	Substn Op'n-Inspect & Tes	3,944.96
50170	Substn Op'n-Supplies & Expense	0.00
50200	O/H Line Operation-Labour	52,310.95
50250	O/H Line Op'n-Supplies & Exp	393.82
50350	O/H Dist Transformer Operation	10,387.03
50400	U/G Line Op'n-Labour	40,832.03
50401	U/G Line Op'n-Stakeouts	228,388.25
50450	U/G Line Op'n-Supplies & Exp	8,808.06
50451	U/G Line Op'n-Stakeouts	2,218.27
50550	U/G Dist Transformer Operation	69,191.56
50551	Dist Trans - Inspect & Test	0.00
50650	Dist Meters-Reverification	158,810.88
50651	Dist Meters-Dispute Test	2,067.71
50652	Dist Meters-Seal Extension	1,905.12
50653	Dist Meters-Technical Training	0.00
50654	Dist Meters-Computer Costs	0.00
50655	Dist Meters-Other	239.87
50701	Customer Premises-Stakeouts	45,665.48
50702	Customer Fire & No Power Calls	69,766.49
50703	Customer Station Maintenance	20,488.50
50800	Engineering & Operations	0.00
50801	Engineering & Ops Training	10,798.10
50950	O/H Lines Op-Rentals Paid	6,895.01
51140	Substation Maintenance	32,533.03
51141	Substn Mtce-Land & Building	31,745.70

47250	Competition Transition Charges	0.00
50050	Operation Supervision	72,376.03
50160	Substn Op'n-Labour	1,668.10
50161	Substn Op'n-Inspect & Tes	2,673.47
50170	Substn Op'n-Supplies & Expense	1,362.79
50200	O/H Line Operation-Labour	25,898.43
50250	O/H Line Op'n-Supplies & Exp	78.70
50350	O/H Dist Transformer Operation	655.40
50400	U/G Line Op'n-Labour	2,778.08
50401	U/G Line Op'n-Stakeouts	13,312.95
50450	U/G Line Op'n-Supplies & Exp	293.17
50451	U/G Line Op'n-Stakeouts	0.00
50550	U/G Dist Transformer Operation	0.00
50551	Dist Trans - Inspect & Test	0.00
50650	Dist Meters-Reverification	5,299.85
50651	Dist Meters-Dispute Test	0.00
50652	Dist Meters-Seal Extension	0.00
50653	Dist Meters-Technical Training	0.00
50654	Dist Meters-Computer Costs	0.00
50655	Dist Meters-Other	0.00
50701	Customer Premises-Stakeouts	18,916.61
50702	Customer Fire & No Power Calls	14,524.19
50703	Customer Station Maintenance	0.00
50800	Engineering & Operations	0.00
50801	Engineering & Ops Training	0.00
50950	O/H Lines Op-Rentals Paid	4,491.77
51140	Substation Maintenance	2,775.07
51141	Substn Mtce-Land & Building	1,887.10

51142	Substn Mtce-Other	0.00	51142	Substn Mtce-Other	0.00
51200	O/H Line Mtce-Poles	186,163.85	51200	O/H Line Mtce-Poles	10,428.04
51201	O/H Line Mtce-Temp Services	19,782.99	51201	O/H Line Mtce-Temp Services	0.00
51250	O/H Line Mtce-Conductor	197,116.17	51250	O/H Line Mtce-Conductor	32,361.70
51251	O/H Line Mtce-Insul Washing	28,870.99	51251	O/H Line Mtce-Insul Washing	0.00
51252	O/H Line Mtce-Serv Upgrades	72,263.99	51252	O/H Line Mtce-Serv Upgrades	27,120.82
51254	O/H Line Mtce-Other	13,948.96	51254	O/H Line Mtce-Other	19,526.26
51350	Tree Trimming & ROW Mtce	67,509.53	51350	Tree Trimming & ROW Mtce	55,696.47
51450	U/G Line Mtce-Conduit	32,002.32	51450	U/G Line Mtce-Conduit	381.48
51500	U/G Line Mtce-Cable	246,842.10	51500	U/G Line Mtce-Cable	1,074.52
51501	U/G Line Mtce-Other	1,475.56	51501	U/G Line Mtce-Other	589.33
51600	Dist Transformer Mtce	85,451.31	51600	Dist Transformer Mtce	4,336.68
51601	Dist Transformer Painting	5,795.44	51601	Dist Transformer Painting	189.86
51602	Dist Transformer Other	235.01	51602	Dist Transformer Other	95.04
51700	Sentinel Light Mtce - Labour	0.00	51700	Sentinel Light Mtce - Labour	0.00
51720	Sentinel Lt Mtce - Mat & ExP	0.00	51720	Sentinel Lt Mtce - Mat & ExP	0.00
51750	Dist Meter Maintenance	40,179.58	51750	Dist Meter Maintenance	87.39
53050	Bill & Collect - Supervision	112,812.82	53050	Bill & Collect - Supervision	0.00
53100	Reading-Labour, Vehicles & Exp	-588.06	53100	Reading-Labour, Vehicles & Exp	16,627.62
53101	Reading-Contract Services	165,141.30	53101	Reading-Contract Services	54,950.29
53102	Reading-Supplies	0.00	53102	Reading-Supplies	0.00
53109	Reading-Other	0.00	53109	Reading-Other	0.00
53150	Billing-Labour & Expenses	107,638.39	53150	Billing-Labour & Expenses	8,302.24
53151	Billing-Postage	169,273.29	53151	Billing-Postage	25,366.53
53152	Billing-Stationery & Supplies	0.00	53152	Billing-Stationery & Supplies	0.00
53153	Billing-Computer Expenses	77,313.09	53153	Billing-Computer Expenses	14,597.26
53154	Billing-Equipment Costs	0.00	53154	Billing-Equipment Costs	0.00
53155	Billing-Printing & Stuffing	75,789.03	53155	Billing-Printing & Stuffing	10,899.35

53156	Billing-Contract Delivery	0.00	53156	Billing-Contract Delivery	0.00
53159	Billing-Other	146,756.22	53159	Billing-Other	33,741.50
53200	Collecting-Lab, Vehicles $ Exp	489,094.39	53200	Collecting-Lab, Vehicles $ Exp	114,502.68
53201	Collecting-Postage	4,708.08	53201	Collecting-Postage	2,176.62
53202	Collecting-Stationery & Suppli	8,903.88	53202	Collecting-Stationery & Suppli	2,596.53
53203	Collecting-Equipment Costs	0.00	53203	Collecting-Equipment Costs	0.00
53205	Collecting-Visa/Bank Card	2,434.13	53205	Collecting-Visa/Bank Card	762.36
53209	Collecting-Other	46,861.71	53209	Collecting-Other	57.66
53250	Collecting-Cash Over & Short	109.73	53250	Collecting-Cash Over & Short	57.98
53350	Billing-Bad Debts	0.00	53350	Billing-Bad Debts	16,705.84
53351	Billing-Conversion Adjustments	0.00	53351	Billing-Conversion Adjustments	0.00
53550	Billing-Bad Debts	145,093.85	53550	Billing-Bad Debts	0.00
54100	Community Relations-Xmas Lts	-9,063.96	54100	Community Relations-Xmas Lts	298.69
54101	Community Relations-Other	49,080.18	54101	Community Relations-Other	16,975.20
55150	Sales Exp-Advertising	2,652.08	55150	Sales Exp-Advertising	3,260.16
56051	Director's Lab & Expense	104,476.66	56051	Director's Lab & Expense	20,613.21
56100	Administration Labour & Exp	573,860.00	56100	Administration Labour & Exp	110,479.83
56101	Admin-Vehicle Exp Unit # 15	0.00	56101	Admin-Vehicle Exp Unit # 15	0.00
56102	Admin-Vehicle Exp Unit # 16	5,825.87	56102	Admin-Vehicle Exp Unit # 16	0.00
56103	Admin-Vehicle Exp Unit # 17	4,576.88	56103	Admin-Vehicle Exp Unit # 17	0.00
56104	Admin-Vehicle Exp Unit # 18	683.77	56104	Admin-Vehicle Exp Unit # 18	0.00
56150	Office Labour & Expenses	272,741.80	56150	Office Labour & Expenses	82,930.64
56151	Admin-Awards & Staff Functions	25,348.46	56151	Admin-Awards & Staff Functions	345.38
56152	Admin-Training, Seminars	15,598.00	56152	Admin-Training, Seminars	0.00
56300	OUTSIDE SERVICES EMPLOYED	231,385.34	56300	OUTSIDE SERVICES EMPLOYED	19,555.26
56350	Insurance-Admin Bldgs	64,519.09	56350	Insurance-Admin Bldgs	10,503.11
56351	Insurance-Substations	13,144.38	56351	Insurance-Substations	2,139.78
56352	Insurance-O/H Lines	13,144.38	56352	Insurance-O/H Lines	2,139.78

56353	Insurance-U/G Lines	13,144.38
56354	Insurance-Transformers	13,144.38
56550	Regulatory Expense	114,666.80
56700	Admin Bldg-Rental	270,260.11
56750	Admin Bldg-Lab & Vehicle	720.00
56751	Admin Bldg-Janitorial	36,602.19
56752	Admin Bldg-Grounds Mtce	18,404.76
56753	Admin Bldg-Utilities	68,483.06
56754	Admin Bldg-Security	7,791.13
56755	Admin Bldg-HVAC Mtce	9,216.42
56756	Admin Bldg-Minor Upgrades	5,735.87
56759	Admin Bldg-Other	3,068.62
56760	Telephone SC/LD/Eq Rent	27,171.03
56761	Telephone-Cellular	7,073.29
56762	Telephone-Other	13,166.03
56770	Admin-Computer Maintenance	733.81
56771	Admin-Computer Minor Purchases	342.42
56772	Admin-Def'd Program Expense	0.00
56773	Admin-Minor Software Purchases	6,480.00
56774	Admin-Software Support	72,395.95
56775	Admin-Internet Service	8,035.20
56779	Admin-Computer Other	63.31
56780	Admin-Office Equipment Mtce	6,812.18
56781	Admin-OE Minor Purchases	502.82
56782	Admin-Office Equip Leasing	14,218.77
56789	Admin-Office Equip Other	450.47
56790	Admin-Office Supplies	23,223.05
56791	Admin-Freight, Courier, Fax	4,141.32

56353	Insurance-U/G Lines	2,139.78
56354	Insurance-Transformers	2,139.78
56550	Regulatory Expense	18,004.89
56700	Admin Bldg-Rental	0.00
56750	Admin Bldg-Lab & Vehicle	0.00
56751	Admin Bldg-Janitorial	2,681.11
56752	Admin Bldg-Grounds Mtce	835.24
56753	Admin Bldg-Utilities	15,724.28
56754	Admin Bldg-Security	2,480.80
56755	Admin Bldg-HVAC Mtce	150.00
56756	Admin Bldg-Minor Upgrades	1,050.00
56759	Admin Bldg-Other	918.42
56760	Telephone SC/LD/Eq Rent	9,705.04
56761	Telephone-Cellular	174.33
56762	Telephone-Other	0.00
56770	Admin-Computer Maintenance	0.00
56771	Admin-Computer Minor Purchases	0.00
56772	Admin-Def'd Program Expense	0.00
56773	Admin-Minor Software Purchases	0.00
56774	Admin-Software Support	13,699.36
56775	Admin-Internet Service	689.99
56779	Admin-Computer Other	20.96
56780	Admin-Office Equipment Mtce	595.54
56781	Admin-OE Minor Purchases	148.77
56782	Admin-Office Equip Leasing	5,647.56
56789	Admin-Office Equip Other	0.00
56790	Admin-Office Supplies	2,905.02
56791	Admin-Freight, Courier, Fax	379.47

56792	Admin-Postage	2,610.00	56792	Admin-Postage	1,186.54
56793	Admin-Bank Charges	31,812.89	56793	Admin-Bank Charges	6,614.15
56799	Admin-Other	0.00	56799	Admin-Other	0.00
57050	Amortization Exp-General Plant	3,955,901.47	57050	Amortization Exp-General Plant	288,171.81
57051	Amortization Exp-Office Equip	16,178.55	57051	Amortization Exp-Office Equip	2,466.75
57052	Amortization Exp-Comp Hardware	66,207.66	57052	Amortization Exp-Comp Hardware	13,133.12
57053	Amortization Exp-Comp Software	168,124.67	57053	Amortization Exp-Comp Software	36,437.66
57054	Amortization Tool & Equip	30,045.29	57054	Amortization Tool & Equip	3,972.28
57055	Amortization Stores Equipment	7,977.69	57055	Amortization Stores Equipment	0.00
57056	Amortization Rolling Stock	326,047.52	57056	Amortization Rolling Stock	10,526.90
57057	Amortization Exp-Street Lts	0.00	57057	Amortization Exp-Street Lts	0.00
57059	Amortization Exp-Cont Cap	-659,088.35	57059	Amortization Exp-Cont Cap	-16,264.08
60050	Interest Exp-Debentures	0.00	60050	Interest Exp-Debentures	6,100.00
60350	Interest Exp-Customer Deposits	-0.31	60350	Interest Exp-Customer Deposits	0.00
60359	Interest Exp-Other	1,375,000.00	60359	Interest Exp-Other	108,926.00
61050	Property Taxes-Substations	37,483.73	61050	Property Taxes-Substations	3,581.16
61051	Property Taxes-O/H Lines	963.18	61051	Property Taxes-O/H Lines	0.00
61052	Property Taxes-Buildings	65,895.09	61052	Property Taxes-Buildings	8,385.93
61053	Capital Tax	130,000.00	61053	Capital Tax	0.00
61100	Income Taxes	2,470,103.12	61100	Income Taxes	0.00
63050	Extraordinary Income	-2,641,205.29	63050	Extraordinary Income	0.00
63100	Extraordinary Deductions	669,122.58	63100	Extraordinary Deductions	0.00
90190	Inclement Weather	89,464.40	90190	Inclement Weather	5,093.96
90200	Unproductive Labour	763.03	90200	Unproductive Labour	0.00
90210	Sfty Mtgs, Line Schl, Seminars	150,401.66	90210	Sfty Mtgs, Line Schl, Semi	14,846.44
90211	Unproductive Labour	38,230.54	90211	Unproductive Labour	3,938.44
90220	Small Tool & Equip Purchases	36,299.02	90220	Small Tool & Equip Purchas	4,030.49
90230	Clothing	13,119.83	90230	Clothing	649.18

90240	Meals & Allowances	723.35	90240	Meals & Allowances	26.00
90250	Major Tool & Equip Depr	0.00	90250	Major Tool & Equip Depr	0.00
90260	Tool & Com Equip Mtce	27,630.09	90260	Tool & Com Equip Mtce	14,021.11
90270	Tool & Equip Demos & Training	136.45	90270	Tool & Equip Demos & Train	630.49
90280	Tool & Equip Rent & Lease	584.05	90280	Tool & Equip Rent & Lease	155.11
90290	Tool & Equip Exp Allocated	0.00	90290	Tool & Equip Exp Allocated	0.00
90410	Stores-Labour & Expense	143,591.27	90410	Stores-Labour & Expense	48,858.89
90420	Stores-Supplies & Expense	12,424.16	90420	Stores-Supplies & Expense	1,416.03
90430	Stores-Inventory Adjustment	134,763.15	90430	Stores-Inventory Adjustment	0.00
90440	Stores-Equipment Mtce	2,874.38	90440	Stores-Equipment Mtce	0.00
90450	Stores-Building Mtce	20,297.26	90450	Stores-Building Mtce	0.00
90460	Stores-Equipment Depreciation	0.00	90460	Stores-Equipment Depreciat	0.62
90470	Stores-Variance	6,446.06	90470	Stores-Variance	0.00
90480	Stores - Minor Material Purch	0.00	90480	Stores - Minor Material Pu	0.00
90490	Stores-Expense Allocated	-605.36	90490	Stores-Expense Allocated	0.00
90510	S/C-Furn, Equip & Supplies	5,094.14	90510	S/C-Furn, Equip & Supplies	0.00
90520	S/C-Bldg Mtce	2,779.30	90520	S/C-Bldg Mtce	0.00
90530	S/C-Equipment Mtce	0.00	90530	S/C-Equipment Mtce	0.00
90540	S/C-Equipment Rent & Lease	383.26	90540	S/C-Equipment Rent & Lease	0.00
90550	S/C-Property Tax & Insurance	0.00	90550	S/C-Property Tax & Insuran	0.00
90590	S/C-Expense Allocated	0.00	90590	S/C-Expense Allocated	0.00
90610	P/R Burden-Retirees' Benefits	47,992.01	90610	P/R Burden-Retirees' Benefits	0.00
90710	Rolling Stock-Licences	9,375.00	90710	Rolling Stock-Licences	1,773.00
90720	Rolling Stock-Supplies & Exp	1,525.72	90720	Rolling Stock-Supplies & E	970.86
90730	Rolling Stock-Insurance	17,555.18	90730	Rolling Stock-Insurance	2,857.82
90740	Rolling Stock-Mtce, Gas & Oil	233,005.21	90740	Rolling Stock-Mtce, Gas &	48,841.39
90741	Vehicle Exp Unit # 02	228.72	90741	Vehicle Exp Unit # 02	0.00
90742	Vehicle Exp Unit #10	4,761.63	90742	Vehicle Exp Unit #10	0.00

90750	Rolling Stock-Building Mtce	26,725.20
90760	Rolling Stock-Amortization	0.00
90770	Rolling Stock-Property Tax/Ins	0.00
90790	Rolling Stock-Exp Allocated	-531,546.12
90810	Engineering-Lab, Vehicle & Exp	257,290.10
90820	Engineering-Supplies & Expense	6,431.38
90830	Engineering-Contract Drafting	0.00
90840	Engineering-Computer Expenses	900.30
90890	Engineering-Expense Allocated	-466,232.50
90900	Payroll Burdens	0.00
90910	P/R Burden - UIC	12,281.99
90920	P/R Burden - CPP	24,563.13
90930	P/R Burden - Emp Health Tax	15,446.11
90940	P/P Burden-Pension & Insurance	60,378.44
90941	Employee Future Benefits Exp	76,670.00
90950	PB-Sick Time	168,659.99
90951	PB-Vacation	287,170.96
90952	PB-Stats/Bereave/Personal etc	360,229.05
90960	P/R Burden - Workers' Comp	3,988.69
90970	P/R Burden - EHC,Dental,Vision	80,601.56
90971	P/R Burden - Future Benefits	0.00
90980	P/R Burden - LT Disability Ins	20,532.50
90990	Payroll Burden Allocated	-1,403,934.29
91000	Contributed Capital expense	0.00
91010	Contributed Capital Expense	0.00
91200	Contributed Capital Amortized	0.00
91210	Contributed Capital Amortized	0.00
91220	Accumulated Contributed	0.00

90750	Rolling Stock-Building Mtc	0.00
90760	Rolling Stock-Amortization	0.00
90770	Rolling Stock-Property Tax	0.00
90790	Rolling Stock-Exp Allocate	0.00
90810	Engineering-Lab, Vehicle &	3,019.19
90820	Engineering-Supplies & Expense	0.00
90830	Engineering-Contract Draft	0.00
90840	Engineering-Computer Expen	0.00
90890	Engineering-Expense Alloca	-88,912.51
90900	Payroll Burdens	180.20
90910	P/R Burden - UIC	2,277.63
90920	P/R Burden - CPP	4,684.71
90930	P/R Burden - Emp Health Ta	3,155.61
90940	P/P Burden-Pension & Insur	11,061.28
90941	Employee Future Benefits E	21,522.00
90950	PB-Sick Time	11,534.44
90951	PB-Vacation	46,834.81
90952	PB-Stats/Bereave/Personal	45,190.58
90960	P/R Burden - Workers' Comp	1,629.32
90970	P/R Burden - EHC,Dental,Vi	15,497.28
90971	P/R Burden - Future Benefi	0.00
90980	P/R Burden - LT Disability	3,480.81
90990	Payroll Burden Allocated	-229,265.18
91000	Contributed Capital expense	0.00
91010	Contributed Capital Expense	0.00
91200	Contributed Capital Amortized	0.00
91210	Contributed Capital Amortized	0.00
91220	Accumulated Contributed	0.00

91300	Employee Benefit Liability	0.00	91300	Employee Benefit Liability	0.00
91310	Employee Benefit Expense	0.00	91310	Employee Benefit Expense	0.00
999991	PA O/H re-allocation clearing	0.00	999991	PA O/H re-allocation clearing	0.00
999999	Suspense (System Generated)	0.00	999999	Suspense (System Generated)	0.00
		-1,180.77			-21,832.73

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND RESULTS FILED

Please find the reconciliation between Results Filed and the Financial Statements for 2007, 2008 and 2009 in the following attachment.

Attachment 1 (of 1):

Reconciliation Tables

Account # USofA	Account Name Grouped as shown on Rate Base Models (all formulae)	2006 Trial Balance Newmarket	2006 Trial Balance Tay	2006 Trial Balance NT Power	2007 Trial Balance Newmarket	2007 Trial Balance Tay	2007 Trial Balance NT Power	2008 Trial Balance Newmarket	2008 Trial Balance Tay	2008 Trial Balance NT Power
18050	Distribution-Land	2,460,709.06	58,066.87	2,518,775.93	2,512,189.95	58,066.87	2,570,256.82	3,046,358.25	58,066.87	3,104,425.12
18060	Distribution-Land Rights	0.00	241,736.72	241,736.72	0.00	241,736.72	241,736.72	222,075.00	241,736.72	463,811.72
18200	Dist Stn-Rec Complex	77,383.00	0.00	77,383.00	77,383.00	0.00	77,383.00	77,383.00	0.00	77,383.00
18201	Dist Stn-Legge	551,050.91	0.00	551,050.91	636,165.66	0.00	636,165.66	656,912.16	0.00	656,912.16
18202	Dist Stn-Thompson	930,481.42	0.00	930,481.42	987,228.74	0.00	987,228.74	994,658.54	0.00	994,658.54
18203	Dist Stn-Broughton/Simmons	1,057,175.69	0.00	1,057,175.69	1,061,522.23	0.00	1,061,522.23	1,062,864.26	0.00	1,062,864.26
18204	Dist Stn-Gilbert	1,120,932.57	0.00	1,120,932.57	1,134,679.71	0.00	1,134,679.71	1,136,841.73	0.00	1,136,841.73
18205	Dist Stn-Andrews	1,112,596.98	0.00	1,112,596.98	1,113,931.67	0.00	1,113,931.67	1,113,931.67	0.00	1,113,931.67
18206	Dist Stn-Leadbeater	685,581.35	0.00	685,581.35	688,398.98	0.00	688,398.98	688,704.98	0.00	688,704.98
18207	Dist Stn-Cook	467,053.80	0.00	467,053.80	473,028.86	0.00	473,028.86	504,800.39	0.00	504,800.39
18208	Dist Stn-Twinney	1,261,278.66	0.00	1,261,278.66	1,262,175.57	0.00	1,262,175.57	1,262,582.97	0.00	1,262,582.97
18209	Dist Stn-S/E Quadrant	523,899.57	0.00	523,899.57	523,899.57	0.00	523,899.57	842,458.09	0.00	842,458.09
18210	Dist Stn-Miscellaneous	15,244.78	0.00	15,244.78	15,244.78	0.00	15,244.78	17,751.55	0.00	17,751.55
18211	Dist Stn Port McNicholl	0.00	108,779.51	108,779.51	0.00	108,852.49	108,852.49	0.00	108,852.49	108,852.49
18212	Dist Stn Victoria Harbour	0.00	285,843.55	285,843.55	0.00	285,843.55	285,843.55	0.00	288,429.95	288,429.95
18213	Dist Stn Waubaushene	0.00	98,161.72	98,161.72	0.00	98,161.72	98,161.72	0.00	98,161.72	98,161.72
18214	Port McNicholl MS 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25,113.34	25,113.34
18300	Dist Lines O/H Poles	10,817,893.38	1,401,244.99	12,219,138.37	11,411,389.98	1,625,620.16	13,037,010.14	12,410,040.77	1,702,963.29	14,113,004.06
18350	Dist Lines O/H Conductor	13,538,608.02	1,407,424.85	14,946,032.87	14,200,846.71	1,432,899.35	15,633,746.06	14,755,661.13	1,500,726.04	16,256,387.17
18400	Dist Lines U/G Conduit	6,703,409.14	246,218.03	6,949,627.17	7,089,918.23	51,660.70	7,141,578.93	7,518,726.99	63,699.67	7,582,426.66
18450	Dist Lines U/G Conductor	21,777,586.01	233,342.83	22,010,928.84	22,497,824.12	280,778.29	22,778,602.41	23,343,595.55	314,790.02	23,658,385.57

18500	Distribution Transformers	13,240,544.02	986,751.16	14,227,295.18	14,183,937.18	1,069,055.09	15,252,992.27	15,152,555.85	1,093,479.21	16,246,035.06
18550	Services	3,021,290.94	1,198,967.22	4,220,258.16	4,197,441.21	1,256,216.59	5,453,657.80	5,230,978.18	1,279,285.11	6,510,263.29
18551	44 KV CAPITAL STUDY	6,530.26	0.00	6,530.26	6,530.26	0.00	6,530.26	6,530.26	0.00	6,530.26
18552	13.8 KV CAPITAL STUDY	2,517.15	0.00	2,517.15	2,517.15	0.00	2,517.15	2,517.15	0.00	2,517.15
18600	Distribution Meters	5,876,373.31	360,896.69	6,237,270.00	3,898,600.06	29,217.00	3,927,817.06	4,369,778.48	32,515.14	4,402,293.62
18610	Smart Meters	0.00	0.00	0.00	3,590,943.84	430,958.77	4,021,902.61	4,346,759.40	524,259.69	4,871,019.09
18650	Wholesale Meters	919,634.49	0.00	919,634.49	919,634.49	0.00	919,634.49	931,181.51	0.00	931,181.51
18750	Distribution Street Lights	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
189999	Capital Holding Account	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19050	General Plant - Land	89.70	0.00	89.70	89.70	0.00	89.70	89.70	0.00	89.70
19080	Buildings	0.00	276,277.15	276,277.15	0.00	279,019.69	279,019.69	0.00	279,019.69	279,019.69
19081	Leasehold Imp-Steven Court	390,126.33	0.00	390,126.33	419,235.50	0.00	419,235.50	456,691.25	0.00	456,691.25
19082	Buildings-Water Street	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19083	Buildings-Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19150	Office Equipment	236,679.33	49,775.70	286,455.03	275,234.59	50,286.61	325,521.20	285,567.97	66,805.11	352,373.08
19200	Computer Hardware	585,881.28	66,565.70	652,446.98	652,492.96	70,631.54	723,124.50	722,808.81	115,827.96	838,636.77
19250	Computer Software	944,826.07	105,761.58	1,050,587.65	1,138,803.98	259,743.30	1,398,547.28	1,185,101.48	280,380.17	1,465,481.65
19300	Transportation Equipment	2,802,289.21	333,865.01	3,136,154.22	2,942,171.74	335,232.23	3,277,403.97	3,667,992.39	335,232.23	4,003,224.62
19350	Stores Equipment	140,871.20	6,384.82	147,256.02	142,098.64	6,384.82	148,483.46	144,862.67	6,384.82	151,247.49
19400	Tools, Shop & Garage Equipment	403,794.25	65,240.34	469,034.59	419,726.09	56,538.62	476,264.71	444,027.79	67,763.22	511,791.01
19450	Measurement & Testing Equip	88,487.88	0.00	88,487.88	102,535.07	0.00	102,535.07	102,535.07	0.00	102,535.07
19650	Water Heater Rental units	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19800	System Supervisory Equipment	723,684.20	0.00	723,684.20	728,163.51	0.00	728,163.51	731,769.42	0.00	731,769.42
19810	System Optimization Study	10,871.57	0.00	10,871.57	10,871.57	0.00	10,871.57	10,871.57	0.00	10,871.57
19850	Sentinel Light Rental Units	13,085.27	9,966.47	23,051.74	13,085.27	9,966.47	23,051.74	13,085.27	9,966.47	23,051.74
19900	Amalco Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19950	Cont Cap to be Amortized	-12,548,042.00	-297,502.09	-12,845,544.09	-13,902,241.83	-364,725.55	-14,266,967.38	-15,466,241.31	-370,979.36	-15,837,220.67

		79,960,418.80	7,243,768.82	87,204,187.62	85,427,698.74	7,672,145.03	93,099,843.77	91,994,809.94	8,122,479.57	100,117,289.51
21052	**Accum Amor-Buildings Other**	0.00	-71,331.77	-71,331.77	0.00	-78,186.30	-78,186.30	0.00	-85,048.30	-85,048.30
21053	**Accum Amor-Stations**	-3,761,509.69	-252,667.44	-4,014,177.13	-3,980,155.54	-270,713.64	-4,250,869.18	-4,247,777.76	-288,934.57	-4,536,712.33
21054	**Accum Amor-O/H Lines**	-11,176,716.79	-1,895,141.04	-13,071,857.83	-12,138,104.14	-1,995,270.83	-14,133,374.97	-13,123,610.43	-2,102,618.89	-15,226,229.32
21055	**Accum Amor-Land Rights**	0.00	-103,087.01	-103,087.01	0.00	-107,857.80	-107,857.80	-3,701.25	-112,606.10	-116,307.35
21056	**Accum Amor-U/G Lines**	-13,753,470.37	-758,345.95	-14,511,816.32	-15,401,454.69	-823,317.01	-16,224,771.70	-16,693,797.13	-884,544.71	-17,578,341.84
21057	**Accum Amor-Transformers**	-6,122,332.69	-583,074.65	-6,705,407.34	-6,757,228.29	-604,072.81	-7,361,301.10	-7,333,019.51	-642,501.90	-7,975,521.41
21058	**Accum Amor-Meters**	-2,963,678.35	-241,913.64	-3,205,591.99	-2,274,498.17	-41,820.19	-2,316,318.36	-2,804,643.82	-104,267.97	-2,908,911.79
21059	**Accum Amor-Street Lights**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21060	**Accum Amor-Office Equipment**	-145,167.19	-45,833.55	-191,000.74	-161,790.70	-46,846.46	-208,637.16	-180,743.96	-48,959.45	-229,703.41
21061	**Accum Amor-Computer Equipment**	-414,215.37	-42,588.49	-456,803.86	-471,169.00	-49,913.39	-521,082.39	-524,907.50	-58,698.90	-583,606.40
21062	**Accum Amor-Computer Software**	-479,598.97	-95,715.43	-575,314.40	-680,282.37	-133,949.57	-814,231.94	-884,112.38	-174,844.55	-1,058,956.93
21063	**Accum Amor-Stores Equipment**	-86,682.38	-6,143.40	-92,825.78	-94,356.86	-6,332.20	-100,689.06	-102,228.58	-6,384.20	-108,612.78
21064	**Accum Amor-Transportation Equi**	-2,062,066.91	-288,365.41	-2,350,432.32	-2,085,392.58	-303,641.95	-2,389,034.53	-2,368,477.05	-314,168.85	-2,682,645.90
21065	**Accum Amor-Tools**	-319,899.80	-54,463.12	-374,362.92	-349,990.36	-49,004.79	-398,995.15	-379,007.84	-51,508.26	-430,516.10
21066	**Accum Amor-Water Heaters**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21067	**Accum Amor-Leasehold**	-280,386.44	0.00	-280,386.44	-326,409.20	0.00	-326,409.20	-374,636.00	0.00	-374,636.00
21068	**Accum Amor-System Supervisory**	-430,932.14	0.00	-430,932.14	-479,178.94	0.00	-479,178.94	-524,179.69	0.00	-524,179.69
21069	**Accum Amor-Sentinel Lights**	-12,581.84	-9,966.47	-22,548.31	-12,847.77	-9,966.47	-22,814.24	-13,085.74	-9,966.47	-23,052.21
21070	**Accum Amor-Street Lights**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21090	**Accum Amor-Cont Cap**	2,006,440.82	19,519.19	2,025,960.01	2,547,269.64	33,091.46	2,580,361.10	3,165,919.29	47,303.17	3,213,222.46
		-40,002,798.11	-4,429,118.18	-44,431,916.29	-42,665,588.97	-4,487,801.95	-47,153,390.92	-46,392,009.35	-4,837,749.95	-51,229,759.30
40800	**SSS Administration Charge**	(90,663.99)	(13,317.82)	(103,981.81)	-91,208.89	-12,070.63	-103,279.52	-93,814.46	-12,363.22	-106,177.68

40801	**Distribution Wheeling Service**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
40802	**Recver Reg Assets prev W/O**	-	-	-	-465,462.67	0.00	-465,462.67	0.00	0.00	0.00
40820	**Retail Service Revenues**	(36,369.20)	-	(36,369.20)	-40,620.60	-416.10	-41,036.70	-39,872.10	-2,376.30	-42,248.40
40840	**STR Revenues**	(1,684.75)	(272.48)	(1,957.23)	-1,512.75	-7,427.70	-8,940.45	-1,383.50	-5,593.00	-6,976.50
42103	**Revenue-Pole Rentals**	(60,762.85)	(71,113.60)	(131,876.45)	-63,091.06	-51,431.55	-114,522.61	-57,369.67	-63,140.03	-120,509.70
42250	**Revenue-Late Payment Charges**	(173,270.62)	(8,673.04)	(181,943.66)	-182,369.86	-8,296.22	-190,666.08	-161,259.73	-20,085.42	-181,345.15
42350	**Revenue-St LT Non-Energy**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
42351	**Account Setup**	(54,337.50)	-	(54,337.50)	-45,387.50	0.00	-45,387.50	-52,375.00	0.00	-52,375.00
42352	**Revenue-Reconnection Charges**	(21,985.00)	(13,733.00)	(35,718.00)	-24,658.52	-15,821.20	-40,479.72	-28,510.00	-15,525.00	-44,035.00
42353	**Revenue-Collection Charges**	(148,705.50)	(2,377.64)	(151,083.14)	-135,133.50	-4,834.95	-139,968.45	-133,947.00	-37,875.00	-171,822.00
42354	**Change of Occupancy-Final Bill**	(46,287.50)	-	(46,287.50)	-41,362.50	0.00	-41,362.50	-43,137.50	0.00	-43,137.50
43102	**Revenue-Sentinel Lt Rentals**	(7,166.66)	(1,733.70)	(8,900.36)	-14,078.40	-1,966.80	-16,045.20	-20,986.80	-1,376.60	-22,363.40
43250	**Revenue-Sale of Scrap Metals**	(20,463.87)	-	(20,463.87)	-17,115.18	0.00	-17,115.18	-10,794.99	0.00	-10,794.99
43251	**Water St-Mark Up on Sales**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
43550	**Gain on Sale of Assets**	(48,270.58)	(1,627.82)	(49,898.40)	-8,372.24	0.00	-8,372.24	0.00	0.00	0.00
43600	**Loss on Sale of Assets**	-	132.96	132.96	987,056.00	126,025.87	1,113,081.87	0.00	0.00	0.00
43850	**Non-Utility Rental Income**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
43851	**Water Heater Rental Income**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
43900	**Revenue-Miscellaneous**	(9,906.17)	(3,069.09)	(12,975.26)	-22,280.65	-20,405.39	-42,686.04	-14,149.00	-7,351.78	-21,500.78
43901	**Revenue-Profit on Mat & Serv**	(15,303.59)	-	(15,303.59)	-13,651.38	-475.00	-14,126.38	-23,710.88	-3,034.78	-26,745.66
43902	**Revenue-Arrears Certificates**	(2,328.50)	-	(2,328.50)	-2,068.61	0.00	-2,068.61	-1,505.71	-80.90	-1,586.61
43903	**Revenue-Power Bill Aggregation**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
43904	**Costs re By-passed Meters**	24,096.80	-	24,096.80	0.00	0.00	0.00	10,000.00	0.00	10,000.00
43905	**Revenue re By-passed Meters**	(4,872.30)	-	(4,872.30)	0.00	0.00	0.00	-29.17	0.00	-29.17
44050	**Interest Earned**	(496,202.01)	(50,012.77)	(546,214.78)	-413,270.59	-53,688.50	-466,959.09	-283,014.83	-33,183.92	-316,198.75
60350	**Interest Exp-Customer Deposits**	93,120.53	4,665.52	97,786.05	114,163.87	5,903.52	120,067.39	126,180.82	4,262.09	130,442.91

				-1,282,495.74			-525,329.68			-1,027,403.38
50050	**Operation Supervision**	0.00	-	-	0.00	0.00	0.00	61,533.46	68,268.39	129,801.85
50160	**Substn Op'n-Labour**	12,138.77	1,653.56	13,792.33	13,451.62	870.54	14,322.16	39,172.63	1,443.75	40,616.38
50161	**Substn Op'n-Inspect & Tes**	15,050.26	1,583.89	16,634.15	25,512.69	1,601.77	27,114.46	25,852.54	947.04	26,799.58
50170	**Substn Op'n-Supplies & Expense**	0.00	-	-	153.81	0.00	153.81	95.87	2,015.54	2,111.41
50200	**O/H Line Operation-Labour**	354,256.54	5,898.42	360,154.96	143,182.75	12,082.14	155,264.89	18,657.84	21,716.03	40,373.87
50250	**O/H Line Op'n-Supplies & Exp**	1,598.77	2,503.93	4,102.70	2,318.67	1,930.87	4,249.54	63,808.05	0.00	63,808.05
50350	**O/H Dist Transformer Operation**	10,407.11	-	10,407.11	12,167.38	894.78	13,062.16	627.64	2,063.63	2,691.27
50400	**U/G Line Op'n-Labour**	117,221.77	-	117,221.77	53,713.67	0.00	53,713.67	32,899.58	3,319.14	36,218.72
50401	**U/G Line Op'n-Stakeouts**	128,355.75	-	128,355.75	181,184.75	0.00	181,184.75	209,581.45	9,602.07	219,183.52
50450	**U/G Line Op'n-Supplies & Exp**	11,138.09	-	11,138.09	18,515.65	67.28	18,582.93	16,100.09	118.15	16,218.24
50451	**U/G Line Op'n-Stakeouts**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
50550	**U/G Dist Transformer Operation**	64,433.94	-	64,433.94	49,377.06	0.00	49,377.06	65,964.10	147.13	66,111.23
50551	**Dist Trans - Inspect & Test**	374.65	-	374.65	0.00	0.00	0.00	1,179.31	0.00	1,179.31
50650	**Dist Meters-Reverification**	115,704.61	11,191.93	126,896.54	155,796.68	22,376.33	178,173.01	153,283.31	1,728.85	155,012.16
50651	**Dist Meters-Dispute Test**	336.48	-	336.48	178.06	0.00	178.06	1,774.65	0.00	1,774.65
50652	**Dist Meters-Seal Extension**	10,221.77	-	10,221.77	862.57	0.00	862.57	6,476.14	0.00	6,476.14
50653	**Dist Meters-Technical Training**	334.64	-	334.64	0.00	0.00	0.00	0.00	0.00	0.00
50654	**Dist Meters-Computer Costs**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
50655	**Dist Meters-Other**	60.99	6,844.01	6,905.00	37.79	25.75	63.54	835.95	0.00	835.95
50701	**Customer Premises-Stakeouts**	33,973.14	18,197.82	52,170.96	40,154.37	15,714.60	55,868.97	42,854.26	25,363.19	68,217.45
50702	**Customer Fire & No Power Calls**	27,318.93	-	27,318.93	37,825.50	642.17	38,467.67	72,613.41	14,262.28	86,875.69
50703	**Customer Station Maintenance**	13,780.11	1,981.94	15,762.05	13,591.19	1,024.76	14,615.95	11,105.16	69.88	11,175.04
50800	**Engineering & Operations**	0.00	20,268.13	20,268.13	0.00	10,430.00	10,430.00	0.00	0.00	0.00
50801	**Engineering & Ops Training**	16,798.56	24.00	16,822.56	18,703.33	2,120.23	20,823.56	12,702.67	237.58	12,940.25

50950	**O/H Lines Op-Rentals Paid**	10,512.93	10,280.06	20,792.99	10,541.54	10,271.06	20,812.60	10,541.54	0.00	10,541.54
51140	**Substation Maintenance**	4,409.41	-	4,409.41	3,773.40	0.00	3,773.40	51,336.15	1,381.63	52,717.78
51141	**Substn Mtce-Land & Building**	9,561.02	-	9,561.02	39,079.70	0.00	39,079.70	22,069.15	915.00	22,984.15
51142	**Substn Mtce-Other**	703.25	77,312.56	78,015.81	0.00	0.00	0.00	0.00	0.00	0.00
51200	**O/H Line Mtce-Poles**	163,186.83	-	163,186.83	218,728.95	19,110.09	237,839.04	121,581.67	-16,431.30	105,150.37
51201	**O/H Line Mtce-Temp Services**	13,427.48	-	13,427.48	-5,131.71	608.62	-4,523.09	-26,967.27	110.35	-26,856.92
51250	**O/H Line Mtce-Conductor**	133,060.75	26,067.10	159,127.85	120,482.32	61,125.55	181,607.87	231,301.23	67,448.63	298,749.86
51251	**O/H Line Mtce-Insul Washing**	23,317.20	-	23,317.20	10,560.00	0.00	10,560.00	21,587.50	0.00	21,587.50
51252	**O/H Line Mtce-Serv Upgrades**	60,940.65	-	60,940.65	78,129.20	0.00	78,129.20	68,811.68	-5,123.56	63,688.12
51254	**O/H Line Mtce-Other**	117.50	9,809.54	9,927.04	1,195.53	9,377.65	10,573.18	2,470.44	1,022.19	3,492.63
51350	**Tree Trimming & ROW Mtce**	56,661.13	-	56,661.13	57,321.05	5,403.36	62,724.41	91,568.16	96,228.22	187,796.38
51450	**U/G Line Mtce-Conduit**	40,285.15	730.80	41,015.95	18,334.39	688.48	19,022.87	11,653.89	378.82	12,032.71
51500	**U/G Line Mtce-Cable**	169,814.62	-	169,814.62	312,743.50	461.33	313,204.83	289,607.31	515.74	290,123.05
51501	**U/G Line Mtce-Other**	374.50	-	374.50	2,185.23	0.00	2,185.23	5,372.00	0.00	5,372.00
51600	**Dist Transformer Mtce**	42,404.35	3,811.27	46,215.62	37,614.98	6,378.92	43,993.90	82,728.16	2,921.70	85,649.86
51601	**Dist Transformer Painting**	1,979.27	-	1,979.27	4,391.73	0.00	4,391.73	16,121.00	0.00	16,121.00
51602	**Dist Transformer Other**	0.00	-	-	1,799.24	0.00	1,799.24	0.00	0.00	0.00
51700	**Sentinel Light Mtce - Labour**	0.00	-	-	0.00	182.74	182.74	0.00	118.80	118.80
51720	**Sentinel Lt Mtce - Mat & ExP**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
51750	**Dist Meter Maintenance**	-1,489.86	25.36	(1,464.50)	32,397.93	910.43	33,308.36	25,656.66	968.25	26,624.91
53050	**Bill & Collect - Supervision**	100,505.40	6,039.35	106,544.75	106,040.86	3,008.04	109,048.90	119,869.56	0.00	119,869.56
53100	**Reading-Labour, Vehicles & Exp**	-273.48	10,778.73	10,505.25	-510.21	17,456.57	16,946.36	-1,065.00	13,779.90	12,714.90
53101	**Reading-Contract Services**	138,944.84	49,733.41	188,678.25	150,585.85	50,350.70	200,936.55	156,953.05	52,886.74	209,839.79
53102	**Reading-Supplies**	0.00	22.50	22.50	0.00	50.00	50.00	0.00	0.00	0.00
53109	**Reading-Other**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
53150	**Billing-Labour & Expenses**	100,102.52	26,325.84	126,428.36	105,182.17	17,941.67	123,123.84	110,373.51	5,916.60	116,290.11
53151	**Billing-Postage**	176,811.73	23,390.62	200,202.35	158,385.70	23,479.99	181,865.69	164,331.67	24,862.70	189,194.37
53152	**Billing-Stationery & Supplies**	9,688.67	5,722.75	15,411.42	12,813.12	5,375.64	18,188.76	0.00	2,010.24	2,010.24
53153	**Billing-Computer Expenses**	43,344.60	25,933.61	69,278.21	44,421.23	25,220.39	69,641.62	43,344.00	12,468.36	55,812.36

53154	**Billing-Equipment Costs**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
53155	**Billing-Printing & Stuffing**	40,191.18	8,416.60	48,607.78	34,737.82	12,615.29	47,353.11	44,603.65	9,896.93	54,500.58
53156	**Billing-Contract Delivery**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
53159	**Billing-Other**	120,513.03	12,468.34	132,981.37	139,256.51	46,667.26	185,923.77	149,367.91	40,849.99	190,217.90
53200	**Collecting-Lab, Vehicles $ Exp**	428,846.89	45,029.52	473,876.41	479,986.12	82,320.40	562,306.52	441,647.80	145,688.51	587,336.31
53201	**Collecting-Postage**	22,814.94	-	22,814.94	4,367.12	0.00	4,367.12	7,334.67	1,300.00	8,634.67
53202	**Collecting-Stationery & Suppli**	10,996.33	765.31	11,761.64	8,183.80	2,160.10	10,343.90	3,220.86	1,034.30	4,255.16
53203	**Collecting-Equipment Costs**	0.00	272.48	272.48	0.00	76.00	76.00	0.00	0.00	0.00
53205	**Collecting-Visa/Bank Card**	1,571.65	200.00	1,771.65	1,938.11	1,107.00	3,045.11	2,142.78	838.58	2,981.36
53209	**Collecting-Other**	52,880.03	(449.10)	52,430.93	67,034.97	1,529.44	68,564.41	47,425.09	3,562.09	50,987.18
53250	**Collecting-Cash Over & Short**	335.11	0.10	335.21	426.17	-490.33	-64.16	-456.68	-365.76	-822.44
53350	**Billing-Bad Debts**	37,705.13	2,260.13	39,965.26	40,381.87	11,417.68	51,799.55	2,895.00	31,752.52	34,647.52
53351	**Billing-Conversion Adjustments**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
53550	**Billing-Bad Debts**	0.00	-	-	0.00	0.00	0.00	111,992.94	0.00	111,992.94
54100	**Community Relations-Xmas Lts**	4,838.95	-	4,838.95	3,384.58	986.78	4,371.36	3,388.46	413.27	3,801.73
54101	**Community Relations-Other**	88,971.98	7,059.34	96,031.32	58,354.16	3,920.69	62,274.85	49,138.74	16,143.99	65,282.73
55150	**Sales Exp-Advertising**	6,493.30	390.00	6,883.30	9,968.02	2,861.34	12,829.36	2,725.00	197.64	2,922.64
56051	**Director's Lab & Expense**	130,104.62	17,064.54	147,169.16	109,467.04	7,087.77	116,554.81	108,403.46	19,718.61	128,122.07
56100	**Administration Labour & Exp**	420,097.52	123,923.63	544,021.15	508,372.85	179,368.82	687,741.67	545,626.62	124,055.55	669,682.17
56101	**Admin-Vehicle Exp Unit # 15**	15,346.01	-	15,346.01	9,402.88	0.00	9,402.88	2,085.30	0.00	2,085.30
56102	**Admin-Vehicle Exp Unit # 16**	8,432.19	-	8,432.19	4,124.39	0.00	4,124.39	6,299.71	0.00	6,299.71
56103	**Admin-Vehicle Exp Unit # 17**	10,912.18	-	10,912.18	2,985.51	0.00	2,985.51	3,199.67	0.00	3,199.67
56104	**Admin-Vehicle Exp Unit # 18**	9,304.71	-	9,304.71	3,549.33	0.00	3,549.33	0.00	0.00	0.00
56150	**Office Labour & Expenses**	122,549.68	21,351.63	143,901.31	192,954.09	92,870.59	285,824.68	232,793.07	93,234.11	326,027.18
56151	**Admin-Awards & Staff Functions**	17,800.31	-	17,800.31	22,515.82	0.00	22,515.82	24,749.75	912.38	25,662.13
56152	**Admin-Training, Seminars**	1,359.55	-	1,359.55	1,792.95	540.00	2,332.95	12,232.37	0.00	12,232.37
56300	**OUTSIDE SERVICES EMPLOYED**	0.00	1,150.18	1,150.18	0.00	0.00	0.00	223,627.50	28,156.24	251,783.74

56350	**Insurance-Admin Bldgs**	6,979.08	9,576.36	16,555.44	8,382.00	10,332.36	18,714.36	15,967.91	2,599.43	18,567.34
56351	**Insurance-Substations**	13,500.00	7,323.51	20,823.51	14,850.00	6,653.02	21,503.02	25,794.31	4,199.08	29,993.39
56352	**Insurance-O/H Lines**	14,000.00	-	14,000.00	15,350.00	0.00	15,350.00	27,022.61	4,453.03	31,475.64
56353	**Insurance-U/G Lines**	14,000.00	-	14,000.00	15,350.00	0.00	15,350.00	27,022.61	4,453.03	31,475.64
56354	**Insurance-Transformers**	14,000.00	-	14,000.00	15,350.00	0.00	15,350.00	27,022.61	4,453.03	31,475.64
56550	**Admin-Fees(Audit, MEA, etc)**	534,377.00	32,700.16	567,077.16	353,495.80	52,220.95	405,716.75	139,208.14	-6,905.10	132,303.04
56700	**Admin Bldg-Rental**	180,000.00	-	180,000.00	270,000.00	8,120.45	278,120.45	270,000.00	0.00	270,000.00
56750	**Admin Bldg-Lab & Vehicle**	1,220.15	-	1,220.15	94.30	0.00	94.30	0.00	0.00	0.00
56751	**Admin Bldg-Janitorial**	21,004.66	-	21,004.66	21,121.46	0.00	21,121.46	21,519.90	2,010.00	23,529.90
56752	**Admin Bldg-Grounds Mtce**	12,587.88	10,429.11	23,016.99	20,625.33	10,910.13	31,535.46	13,238.86	2,480.20	15,719.06
56753	**Admin Bldg-Utilities**	65,694.31	-	65,694.31	68,935.55	0.00	68,935.55	72,663.24	13,388.09	86,051.33
56754	**Admin Bldg-Security**	1,504.41	-	1,504.41	3,678.41	0.00	3,678.41	4,088.18	2,032.12	6,120.30
56755	**Admin Bldg-HVAC Mtce**	7,579.51	-	7,579.51	7,914.91	0.00	7,914.91	6,292.00	1,200.05	7,492.05
56756	**Admin Bldg-Minor Upgrades**	960.05	-	960.05	43.17	0.00	43.17	3,420.48	2,266.47	5,686.95
56759	**Admin Bldg-Other**	3,810.62	-	3,810.62	3,323.64	0.00	3,323.64	4,755.02	547.66	5,302.68
56760	**Telephone SC/LD/Eq Rent**	14,295.05	-	14,295.05	22,231.77	0.00	22,231.77	23,600.41	6,787.28	30,387.69
56761	**Telephone-Cellular**	3,541.98	-	3,541.98	5,454.36	323.51	5,777.87	4,146.00	742.05	4,888.05
56762	**Telephone-Other**	3,318.73	-	3,318.73	7,230.07	0.00	7,230.07	19,489.45	0.00	19,489.45
56770	**Admin-Computer Maintenance**	1,055.59	9,261.74	10,317.33	1,150.74	0.00	1,150.74	931.50	36.62	968.12
56771	**Admin-Computer Minor Purchases**	308.87	1,539.00	1,847.87	1,844.19	1,090.37	2,934.56	491.93	107.99	599.92
56772	**Admin-Def'd Program Expense**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
56773	**Admin-Minor Software Purchases**	5,940.00	-	5,940.00	6,523.19	0.00	6,523.19	10,142.29	666.24	10,808.53
56774	**Admin-Software Support**	59,080.04	-	59,080.04	63,885.08	0.00	63,885.08	71,498.54	8,675.02	80,173.56
56775	**Admin-Internet Service**	4,730.40	-	4,730.40	8,035.20	0.00	8,035.20	8,140.55	1,172.70	9,313.25
56779	**Admin-Computer Other**	1,971.00	-	1,971.00	1,351.73	0.00	1,351.73	0.00	0.00	0.00
56780	**Admin-Office Equipment Mtce**	-3,671.07	-	(3,671.07)	5,512.61	0.00	5,512.61	7,385.14	515.35	7,900.49
56781	**Admin-OE Minor Purchases**	382.25	-	382.25	249.99	0.00	249.99	693.00	0.00	693.00

56782	**Admin-Office Equip Leasing**	13,506.06	-	13,506.06	12,960.02	0.00	12,960.02	10,035.65	4,899.09	14,934.74
56789	**Admin-Office Equip Other**	0.00	-	-	0.00	0.00	0.00	0.00	0.00	0.00
56790	**Admin-Office Supplies**	10,578.55	-	10,578.55	14,199.45	-836.01	13,363.44	21,042.59	4,944.04	25,986.63
56791	**Admin-Freight, Courier, Fax**	6,189.01	-	6,189.01	7,749.67	0.00	7,749.67	5,740.84	119.67	5,860.51
56792	**Admin-Postage**	5,000.00	-	5,000.00	3,009.32	0.00	3,009.32	3,740.00	956.22	4,696.22
56793	**Admin-Bank Charges**	40,502.55	-	40,502.55	36,000.67	420.32	36,420.99	35,066.21	1,842.11	36,908.32
56799	**Admin-Other**	0.00	39,830.07	39,830.07	0.00	22,922.32	22,922.32	460.70	177.65	638.35
57050	**Amortization Exp-General Plant**	3,534,389.29	272,811.88	3,807,201.17	3,651,080.93	261,332.21	3,912,413.14	3,748,494.17	304,805.86	4,053,300.03
57051	**Amortization Exp-Office Equip**	15,158.92	1,137.34	16,296.26	16,623.51	1,012.91	17,636.42	18,953.26	2,112.99	21,066.25
57052	**Amortization Exp-Comp Hardware**	49,132.50	8,057.57	57,190.07	56,953.63	7,324.90	64,278.53	53,738.50	8,785.51	62,524.01
57053	**Amortization Exp-Comp Software**	159,037.77	12,596.35	171,634.12	200,683.40	38,234.14	238,917.54	203,830.01	40,894.98	244,724.99
57054	**Amortization Exp-Water Heaters**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
57055	**Amortization Exp-Load Mgmnt**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
57056	**Amortization Exp-Sentinel Lts**	313.56	-	313.56	265.93	0.00	265.93	237.97	0.00	237.97
57057	**Amortization Exp-Street Lts**	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00
57059	**Amortization Exp-Cont Cap**	(501,921.68)	(11,879.27)	(513,800.95)	-540,828.82	-15,399.87	-556,228.69	-618,649.65	-14,211.71	-632,861.36
60050	**Interest Exp-Debentures**	-	43,506.50	43,506.50	0.00	30,985.00	30,985.00	0.00	20,004.75	20,004.75
60350	**Interest Exp-Customer Deposits**	93,120.53	4,665.52	97,786.05	114,163.87	5,903.52	120,067.39	126,180.82	4,262.09	130,442.91
60359	**Interest Exp-Other**	1,685,000.00	141,105.75	1,826,105.75	1,374,995.48	108,926.00	1,483,921.48	1,375,000.00	108,926.00	1,483,926.00
61050	**Property Taxes-Substations**	36,678.27	14,434.56	51,112.83	40,410.74	14,351.04	54,761.78	49,167.09	7,705.63	56,872.72
61051	**Property Taxes-O/H Lines**	898.13	-	898.13	920.15	0.00	920.15	941.45	0.00	941.45
61052	**Property Taxes-Buildings**	65,520.34	-	65,520.34	66,174.92	0.00	66,174.92	67,628.97	6,833.63	74,462.60
61053	**Capital Tax**	-	-	-	150,000.00	0.00	150,000.00	128,000.00	0.00	128,000.00
61100	**Income Taxes**	2,070,422.09	265,496.67	2,335,918.76	1,924,999.27	37,288.83	1,962,288.10	1,607,995.55	0.00	1,607,995.55

Account		2009			2010		
#	Name	Trial Balance			Trial Balance		
		Newmarket	Tay	NT Power	Newmarket	Tay	NT Power
USofA	Grouped as shown on Rate Base Models (all formulae)						
18050	Distribution-Land	3,070,162.31	58,066.87	3,128,229.18	3,070,252.01	58,066.87	3,128,318.88
18060	Distribution-Land Rights	348,064.99	241,736.72	589,801.71	348,064.99	241,736.72	589,801.71
18200	Dist Stn-Rec Complex	77,383.00	0.00	77,383.00			
18201	Dist Stn-Legge	656,912.16	0.00	656,912.16			
18202	Dist Stn-Thompson	994,658.54	0.00	994,658.54			
18203	Dist Stn-Broughton/Simmons	1,062,864.26	0.00	1,062,864.26			
18204	Dist Stn-Gilbert	1,136,841.73	0.00	1,136,841.73			
18205	Dist Stn-Andrews	1,113,931.67	0.00	1,113,931.67			
18206	Dist Stn-Leadbeater	688,704.98	0.00	688,704.98			
18207	Dist Stn-Cook	504,800.39	0.00	504,800.39			
18208	Dist Stn-Twinney	1,262,582.97	0.00	1,262,582.97			
18209	Dist Stn-S/E Quadrant	559,816.98	0.00	559,816.98			
18210	Dist Stn-Miscellaneous	22,320.21	0.00	22,320.21	9,788,680.81		9,788,680.81
18211	Dist Stn Port McNicholl	0.00	108,852.49	108,852.49			
18212	Dist Stn Victoria Harbour	0.00	288,429.95	288,429.95			
18213	Dist Stn Waubaushene	0.00	98,161.72	98,161.72			
18214	Port McNicholl MS 2	0.00	380,680.32	380,680.32		520,557.50	520,557.50
18300	Dist Lines O/H Poles	13,180,233.09	1,724,320.50	14,904,553.59	15,319,870.08	1,867,363.46	17,187,233.54
18350	Dist Lines O/H Conductor	15,414,035.00	1,618,138.97	17,032,173.97	17,539,813.14	1,864,898.71	19,404,711.85
18400	Dist Lines U/G Conduit	8,365,725.46	71,087.02	8,436,812.48	8,901,190.85	68,161.56	8,969,352.41

18450	**Dist Lines U/G Conductor**	24,928,039.17	422,286.93	25,350,326.10	26,586,593.33	362,753.06	26,949,346.39
18500	**Distribution Transformers**	16,158,718.86	1,109,710.38	17,268,429.24	17,611,791.12	1,136,491.39	18,748,282.50
18550	**Services**	6,504,448.86	1,303,055.61	7,807,504.47	7,176,529.96	1,314,492.55	8,491,022.51
18551	**44 KV CAPITAL STUDY**	6,530.26	0.00	6,530.26			
18552	**13.8 KV CAPITAL STUDY**	2,517.15	0.00	2,517.15			
18600	**Distribution Meters**	4,547,259.01	31,047.66	4,578,306.67	7,565,969.39	365,911.46	7,931,880.85
18610	**Smart Meters**	4,734,027.53	610,276.93	5,344,304.46	6,613,348.36	758,506.64	7,371,855.01
18650	**Wholesale Meters**	933,208.61	0.00	933,208.61			
18750	**Distribution Street Lights**	0.00	0.00	0.00			
189999	**Capital Holding Account**	0.00	0.00	0.00			
19050	**General Plant - Land**	89.70	0.00	89.70			
19080	**Buildings**	0.00	297,911.58	297,911.58		297,911.58	297,911.58
19081	**Leasehold Imp-Steven Court**	710,826.12	0.00	710,826.12	805,826.12		805,826.12
19082	**Buildings-Water Street**	0.00	0.00	0.00			
19083	**Buildings-Other**	0.00	0.00	0.00			
19150	**Office Equipment**	303,475.40	67,514.87	370,990.27	313,475.40	69,554.87	383,030.27
19200	**Computer Hardware**	748,704.36	116,028.62	864,732.98	788,704.36	121,128.62	909,832.98
19250	**Computer Software**	1,216,321.64	287,475.75	1,503,797.39	1,466,321.64	297,675.75	1,763,997.39
19300	**Transportation Equipment**	4,014,755.54	203,432.00	4,218,187.54	4,129,755.54	203,432.00	4,333,187.54
19350	**Stores Equipment**	144,862.67	6,384.82	151,247.49	144,862.67	6,384.82	151,247.49
19400	**Tools, Shop & Garage Equipment**	465,031.58	65,721.78	530,753.36	500,031.58	75,721.78	575,753.36
19450	**Measurement & Testing Equip**	102,535.07	0.00	102,535.07	137,535.07		137,535.07
19650	**Water Heater Rental units**	0.00	0.00	0.00			
19800	**System Supervisory Equipment**	731,769.42	0.00	731,769.42	742,640.99		742,640.99
19810	**System Optimization Study**	10,871.57	0.00	10,871.57			
19850	**Sentinel Light Rental Units**	13,085.27	9,966.47	23,051.74			
19900	**Amalco Capital**	0.00	0.00	0.00			
19950	**Cont Cap to be Amortized**	-17,488,176.09	-466,425.82	-17,954,601.91	-20,143,999.29	-409,217.55	-20,553,216.84
		97,247,939.44	8,653,862.14	105,901,801.58	109,407,258.13	9,221,531.79	118,628,789.92

21052	**Accum Amor-Buildings Other**	0.00	-92,288.14	-92,288.14	0.00	-99,554.28	-99,554.28
21053	**Accum Amor-Stations**	-4,517,084.87	-315,204.05	-4,832,288.92	-4,798,388.35	-332,555.96	-5,130,944.32
21054	**Accum Amor-O/H Lines**	-14,199,792.93	-2,206,593.79	-16,406,386.72	-15,332,910.62	-2,323,960.03	-17,656,870.64
21055	**Accum Amor-Land Rights**	-13,144.90	-117,354.40	-130,499.30	-24,747.07	-125,412.29	-150,159.36
21056	**Accum Amor-U/G Lines**	-18,108,196.49	-947,720.19	-19,055,916.68	-19,664,100.96	-1,017,802.98	-20,681,903.94
21057	**Accum Amor-Transformers**	-7,946,387.81	-681,005.86	-8,627,393.67	-8,567,831.48	-719,939.61	-9,287,771.09
21058	**Accum Amor-Meters**	-3,323,082.67	-142,386.72	-3,465,469.39	-5,069,196.20	-437,375.38	-5,506,571.58
21059	**Accum Amor-Street Lights**	0.00	0.00	0.00	0.00		0.00
21060	**Accum Amor-Office Equipment**	-196,922.51	-51,085.49	-248,008.00	-217,547.84	-53,121.42	-270,669.26
21061	**Accum Amor-Computer Equipment**	-591,115.16	-71,832.02	-662,947.18	-659,318.64	-85,110.58	-744,429.22
21062	**Accum Amor-Computer Software**	-1,052,237.05	-211,282.21	-1,263,519.26	-1,154,807.98	-248,455.73	-1,403,263.70
21063	**Accum Amor-Stores Equipment**	-110,206.27	-6,384.82	-116,591.09	-118,492.59	-6,385.20	-124,877.79
21064	**Accum Amor-Transportation Equi**	-2,694,524.57	-192,971.52	-2,887,496.09	-3,009,997.71	-202,805.12	-3,212,802.83
21065	**Accum Amor-Tools**	-409,053.13	-48,322.91	-457,376.04	-440,345.13	-51,634.51	-491,979.63
21066	**Accum Amor-Water Heaters**	0.00	0.00	0.00	0.00		0.00
21067	**Accum Amor-Leasehold**	-415,979.96	0.00	-415,979.96	-499,586.31		-499,586.31
21068	**Accum Amor-System Supervisory**	-563,910.28	0.00	-563,910.28	-595,106.55		-595,106.55
21069	**Accum Amor-Sentinel Lights**	-13,085.74	-9,966.47	-23,052.21	0.00	0.00	0.00
21070	**Accum Amor-Street Lights**	0.00	0.00	0.00	0.00		0.00
21090	**Accum Amor-Cont Cap**	3,825,007.64	63,567.25	3,888,574.89	4,577,651.15	79,171.19	4,656,822.34
		-50,329,716.70	-5,030,831.34	-55,360,548.04	-55,574,726.27	-5,624,941.89	-61,199,668.16
40800	**SSS Administration Charge**	-95,796.49	-12,201.85	-107,998.34			
40801	**Distribution Wheeling Service**	0.00	0.00	0.00			
40802	**Recver Reg Assets prev W/O**	0.00	0.00	0.00			
40820	**Retail Service Revenues**	-41,972.00	-5,113.20	-47,085.20			
40840	**STR Revenues**	-617.75	-3,631.25	-4,249.00			
42103	**Revenue-Pole Rentals**	-63,224.37	-61,002.51	-124,226.88			

42250	**Revenue-Late Payment Charges**	-190,346.68	-24,191.25	-214,537.93
42350	**Revenue-St LT Non-Energy**	0.00	0.00	0.00
42351	**Account Setup**	-53,050.00	-7,410.00	-60,460.00
42352	**Revenue-Reconnection Charges**	-23,780.00	-6,785.00	-30,565.00
42353	**Revenue-Collection Charges**	-147,701.22	-36,615.00	-184,316.22
42354	**Change of Occupancy-Final Bill**	-42,025.00	0.00	-42,025.00
43102	**Revenue-Sentinel Lt Rentals**	-20,761.80	-1,357.80	-22,119.60
43250	**Revenue-Sale of Scrap Metals**	-11,489.64	0.00	-11,489.64
43251	**Water St-Mark Up on Sales**	0.00	0.00	0.00
43550	**Gain on Sale of Assets**	0.00	0.00	0.00
43600	**Loss on Sale of Assets**	0.00	994.92	994.92
43850	**Non-Utility Rental Income**	-2,186.62	0.00	-2,186.62
43851	**Water Heater Rental Income**	0.00	0.00	0.00
43900	**Revenue-Miscellaneous**	0.00	-7,994.21	-7,994.21
43901	**Revenue-Profit on Mat & Serv**	-4,560.97	-1,041.33	-5,602.30
43902	**Revenue-Arrears Certificates**	-1,596.00	-45.00	-1,641.00
43903	**Revenue-Power Bill Aggregation**	0.00	0.00	0.00
43904	**Costs re By-passed Meters**	0.00	0.00	0.00
43905	**Revenue re By-passed Meters**	-59.50	0.00	-59.50
44050	**Interest Earned**	-50,966.83	-3,594.23	-54,561.06
60350	**Interest Exp-Customer Deposits**	-0.31	0.00	-0.31
50050	**Operation Supervision**	72,481.43	71,375.46	143,856.89
50160	**Substn Op'n-Labour**	20,637.71	1,668.10	22,305.81
50161	**Substn Op'n-Inspect & Tes**	3,944.96	2,673.47	6,618.43
50170	**Substn Op'n-Supplies & Expense**	0.00	1,362.79	1,362.79
50200	**O/H Line Operation-Labour**	52,310.95	25,898.43	78,209.38
50250	**O/H Line Op'n-Supplies & Exp**	393.82	78.70	472.52

50350	**O/H Dist Transformer Operation**	10,387.03	655.40	11,042.43
50400	**U/G Line Op'n-Labour**	40,832.03	2,778.08	43,610.11
50401	**U/G Line Op'n-Stakeouts**	228,388.25	13,312.95	241,701.20
50450	**U/G Line Op'n-Supplies & Exp**	8,808.06	293.17	9,101.23
50451	**U/G Line Op'n-Stakeouts**	2,218.27	0.00	2,218.27
50550	**U/G Dist Transformer Operation**	69,191.56	0.00	69,191.56
50551	**Dist Trans - Inspect & Test**	0.00	0.00	0.00
50650	**Dist Meters-Reverification**	158,810.88	5,299.85	164,110.73
50651	**Dist Meters-Dispute Test**	2,067.71	0.00	2,067.71
50652	**Dist Meters-Seal Extension**	1,905.12	0.00	1,905.12
50653	**Dist Meters-Technical Training**	0.00	0.00	0.00
50654	**Dist Meters-Computer Costs**	0.00	0.00	0.00
50655	**Dist Meters-Other**	239.87	0.00	239.87
50701	**Customer Premises-Stakeouts**	45,665.48	18,916.61	64,582.09
50702	**Customer Fire & No Power Calls**	69,766.49	14,524.19	84,290.68
50703	**Customer Station Maintenance**	20,488.50	0.00	20,488.50
50800	**Engineering & Operations**	0.00	0.00	0.00
50801	**Engineering & Ops Training**	10,798.10	0.00	10,798.10
50950	**O/H Lines Op-Rentals Paid**	6,895.01	4,491.77	11,386.78
51140	**Substation Maintenance**	32,533.03	2,775.07	35,308.10
51141	**Substn Mtce-Land & Building**	31,745.70	1,887.10	33,632.80
51142	**Substn Mtce-Other**	0.00	0.00	0.00
51200	**O/H Line Mtce-Poles**	186,163.85	10,428.04	196,591.89
51201	**O/H Line Mtce-Temp Services**	19,782.99	0.00	19,782.99
51250	**O/H Line Mtce-Conductor**	197,116.17	32,361.70	229,477.87
51251	**O/H Line Mtce-Insul Washing**	28,870.99	0.00	28,870.99
51252	**O/H Line Mtce-Serv Upgrades**	72,263.99	27,120.82	99,384.81
51254	**O/H Line Mtce-Other**	13,948.96	19,526.26	33,475.22
51350	**Tree Trimming & ROW Mtce**	67,509.53	55,696.47	123,206.00
51450	**U/G Line Mtce-Conduit**	32,002.32	381.48	32,383.80

51500	U/G Line Mtce-Cable	246,842.10	1,074.52	247,916.62
51501	U/G Line Mtce-Other	1,475.56	589.33	2,064.89
51600	Dist Transformer Mtce	85,451.31	4,336.68	89,787.99
51601	Dist Transformer Painting	5,795.44	189.86	5,985.30
51602	Dist Transformer Other	235.01	95.04	330.05
51700	Sentinel Light Mtce - Labour	0.00	0.00	0.00
51720	Sentinel Lt Mtce - Mat & ExP	0.00	0.00	0.00
51750	Dist Meter Maintenance	40,179.58	87.39	40,266.97
53050	Bill & Collect - Supervision	112,812.82	0.00	112,812.82
53100	Reading-Labour, Vehicles & Exp	-588.06	16,627.62	16,039.56
53101	Reading-Contract Services	165,141.30	54,950.29	220,091.59
53102	Reading-Supplies	0.00	0.00	0.00
53109	Reading-Other	0.00	0.00	0.00
53150	Billing-Labour & Expenses	107,638.39	8,302.24	115,940.63
53151	Billing-Postage	169,273.29	25,366.53	194,639.82
53152	Billing-Stationery & Supplies	0.00	0.00	0.00
53153	Billing-Computer Expenses	77,313.09	14,597.26	91,910.35
53154	Billing-Equipment Costs	0.00	0.00	0.00
53155	Billing-Printing & Stuffing	75,789.03	10,899.35	86,688.38
53156	Billing-Contract Delivery	0.00	0.00	0.00
53159	Billing-Other	146,756.22	33,741.50	180,497.72
53200	Collecting-Lab, Vehicles $ Exp	489,094.39	114,502.68	603,597.07
53201	Collecting-Postage	4,708.08	2,176.62	6,884.70
53202	Collecting-Stationery & Suppli	8,903.88	2,596.53	11,500.41
53203	Collecting-Equipment Costs	0.00	0.00	0.00
53205	Collecting-Visa/Bank Card	2,434.13	762.36	3,196.49
53209	Collecting-Other	46,861.71	57.66	46,919.37
53250	Collecting-Cash Over & Short	109.73	57.98	167.71
53350	Billing-Bad Debts	0.00	16,705.84	16,705.84

53351	**Billing-Conversion Adjustments**	0.00	0.00	0.00
53550	**Billing-Bad Debts**	145,093.85	0.00	145,093.85
54100	**Community Relations-Xmas Lts**	-9,063.96	298.69	-8,765.27
54101	**Community Relations-Other**	49,080.18	16,975.20	66,055.38
55150	**Sales Exp-Advertising**	2,652.08	3,260.16	5,912.24
56051	**Director's Lab & Expense**	104,476.66	20,613.21	125,089.87
56100	**Administration Labour & Exp**	573,860.00	110,479.83	684,339.83
56101	**Admin-Vehicle Exp Unit # 15**	0.00	0.00	0.00
56102	**Admin-Vehicle Exp Unit # 16**	5,825.87	0.00	5,825.87
56103	**Admin-Vehicle Exp Unit # 17**	4,576.88	0.00	4,576.88
56104	**Admin-Vehicle Exp Unit # 18**	683.77	0.00	683.77
56150	**Office Labour & Expenses**	272,741.80	82,930.64	355,672.44
56151	**Admin-Awards & Staff Functions**	25,348.46	345.38	25,693.84
56152	**Admin-Training, Seminars**	15,598.00	0.00	15,598.00
56300	**OUTSIDE SERVICES EMPLOYED**	231,385.34	19,555.26	250,940.60
56350	**Insurance-Admin Bldgs**	64,519.09	10,503.11	75,022.20
56351	**Insurance-Substations**	13,144.38	2,139.78	15,284.16
56352	**Insurance-O/H Lines**	13,144.38	2,139.78	15,284.16
56353	**Insurance-U/G Lines**	13,144.38	2,139.78	15,284.16
56354	**Insurance-Transformers**	13,144.38	2,139.78	15,284.16
56550	**Admin-Fees(Audit, MEA, etc)**	114,666.80	18,004.89	132,671.69
56700	**Admin Bldg-Rental**	270,260.11	0.00	270,260.11
56750	**Admin Bldg-Lab & Vehicle**	720.00	0.00	720.00
56751	**Admin Bldg-Janitorial**	36,602.19	2,681.11	39,283.30
56752	**Admin Bldg-Grounds Mtce**	18,404.76	835.24	19,240.00
56753	**Admin Bldg-Utilities**	68,483.06	15,724.28	84,207.34
56754	**Admin Bldg-Security**	7,791.13	2,480.80	10,271.93
56755	**Admin Bldg-HVAC Mtce**	9,216.42	150.00	9,366.42
56756	**Admin Bldg-Minor Upgrades**	5,735.87	1,050.00	6,785.87
56759	**Admin Bldg-Other**	3,068.62	918.42	3,987.04

56760	**Telephone SC/LD/Eq Rent**	27,171.03	9,705.04	36,876.07
56761	**Telephone-Cellular**	7,073.29	174.33	7,247.62
56762	**Telephone-Other**	13,166.03	0.00	13,166.03
56770	**Admin-Computer Maintenance**	733.81	0.00	733.81
56771	**Admin-Computer Minor Purchases**	342.42	0.00	342.42
56772	**Admin-Def'd Program Expense**	0.00	0.00	0.00
56773	**Admin-Minor Software Purchases**	6,480.00	0.00	6,480.00
56774	**Admin-Software Support**	72,395.95	13,699.36	86,095.31
56775	**Admin-Internet Service**	8,035.20	689.99	8,725.19
56779	**Admin-Computer Other**	63.31	20.96	84.27
56780	**Admin-Office Equipment Mtce**	6,812.18	595.54	7,407.72
56781	**Admin-OE Minor Purchases**	502.82	148.77	651.59
56782	**Admin-Office Equip Leasing**	14,218.77	5,647.56	19,866.33
56789	**Admin-Office Equip Other**	450.47	0.00	450.47
56790	**Admin-Office Supplies**	23,223.05	2,905.02	26,128.07
56791	**Admin-Freight, Courier, Fax**	4,141.32	379.47	4,520.79
56792	**Admin-Postage**	2,610.00	1,186.54	3,796.54
56793	**Admin-Bank Charges**	31,812.89	6,614.15	38,427.04
56799	**Admin-Other**	0.00	0.00	0.00
57050	**Amortization Exp-General Plant**	3,955,901.47	288,171.81	4,244,073.28
57051	**Amortization Exp-Office Equip**	16,178.55	2,466.75	18,645.30
57052	**Amortization Exp-Comp Hardware**	66,207.66	13,133.12	79,340.78
57053	**Amortization Exp-Comp Software**	168,124.67	36,437.66	204,562.33
57054	**Amortization Exp-Water Heaters**	30,045.29	3,972.28	34,017.57
57055	**Amortization Exp-Load Mgmnt**	7,977.69	0.00	7,977.69
57056	**Amortization Exp-Sentinel Lts**	326,047.52	10,526.90	336,574.42
57057	**Amortization Exp-Street Lts**	0.00	0.00	0.00
57059	**Amortization Exp-Cont Cap**	-659,088.35	-16,264.08	-675,352.43
60050	**Interest Exp-Debentures**	0.00	6,100.00	6,100.00

60350	**Interest Exp-Customer Deposits**	-0.31	0.00	-0.31
60359	**Interest Exp-Other**	1,375,000.00	108,926.00	1,483,926.00
61050	**Property Taxes-Substations**	37,483.73	3,581.16	41,064.89
61051	**Property Taxes-O/H Lines**	963.18	0.00	963.18
61052	**Property Taxes-Buildings**	65,895.09	8,385.93	74,281.02
61053	**Capital Tax**	130,000.00	0.00	130,000.00
61100	**Income Taxes**	2,470,103.12	0.00	2,470,103.12

FINANCIAL PROJECTIONS

The following section presents evidence related to financial projections. The information presented includes the following;

- Budget Directives and Assumptions
- Recent or anticipated change in Methodology
- 2010 Pro-formas

Budget Directives and Assumptions

The Applicant compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is compiled for both the Bridge and Test Years.

Revenue Forecast

The revenue budget is comprised of three components: energy revenue, distribution revenue and other revenue.

The energy revenue for 2010 was forecast using the weather normalized load forecast as presented by the Elenchus Research Associates ("ERA") Report Medium Term Weather Normalized Distribution System Load Forecast 2009 to 2010, and is discussed in Exhibit 3, Tab 1, Schedule 2. A commodity price of $.0610 per kWh based on the OEB Regulated Price Plan Report dated April 15, 2009 has been assumed for the forecast.

Distribution revenue was forecast using the weather normalized volumes multiplied by both current approved distribution rates and by proposed rates in order to project distribution revenue for the 2009 test year. Other revenue was reviewed on an item for item basis and other revenue was determined based on the most reliable historical indicator.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2009 Actual and 2010 Test Year have been forecasted using a zero based methodology. Each item is reviewed by account for each of the forecast years. A review of historical costs is completed and where applicable costs are included in the budget for the following year. New expenditures are added after the Board or Director and Management approve the expenditure.

Capital Budget

The capital budget process begins with a review of the previous year's work. All capital expenditures are budgeted on a line by line and/or project basis based on need and forecasted customer growth. In addition, The Applicant completes ground inspections throughout the year while completing maintenance on the distribution system and other infrastructure. From these inspections capital projects are identified and prioritized for inclusion in an upcoming capital budget year. A more detailed analysis of the Capital Budget process is provided at Exhibit 2, Tab 4, Schedule 2.

Attachment 2 (of 3):

Changes in Methodology

The Applicant does not propose any changes to its budget process unless otherwise instructed by the Board.

Attachment 3 (of 3):

2009-2010 Pro-Forma Financial Statements

Newmarket-Tay Power Distribution Ltd.
Proforma Profit & Loss Under existing Rates
For the Year Ended Dec 31, 2010

Sales		71,783,522
Cost of Sales		56,931,933
Gross Profit		**14,851,590**
Expenses		
	Amortization	4,525,690
	Administration	2,798,398
	System Operation and Maintenance	2,560,224
	Customer Billing and Collecting	2,331,264
	Community Relations	76,332
	Interest Deemed	2,164,584
	Property and Capital Taxes	173,946
		14,630,438
Income Before Undernoted Items and Income Taxes		221,152
Other Income		
	Occupancy, Connection and Collection Fees	513,521
	Service and Retailer Charges	159,956
	Rental	125,305
	Gain on Sale of Property , Plant and Equipment	0
		798,781
Income Before Income Taxes		**1,019,933**
Provision for Income Taxes (@32%)		**326,379**
Net Income		**693,555**

Newmarket-Tay Power Distribution Ltd. Proforma Profit & Loss Under new rates For the Year Ended Dec 31, 2010		
Sales		74,400,798
Cost of Sales		56,931,933
Gross Profit		**17,468,866**
Expenses		
	Amortization	4,525,690
	Administration	2,798,398
	System Operation and Maintenance	2,560,224
	Customer Billing and Collecting	2,331,264
	Community Relations	76,332
	Interest Deemed	2,164,584
	Property and Capital Taxes	173,946
		14,630,438
Income Before Undernoted Items and Income Taxes		**2,838,428**
Other Income		
	Occupancy, Connection and Collection Fees	561,100
	Service and Retailer Charges	159,956
	Rental	125,305
	Gain on Sale of Property , Plant and Equipment	0
		846,360
Income Before Income Taxes		**3,684,789**
Provision for Income Taxes (@31%)		**1,154,088**
Net Income		**2,530,701**

PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

The Applicant does not issue shares nor does it produce a prospectus.

MATERIALITY THRESHOLD

Except where specifically identified, the materiality threshold used within this application is in compliance with Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated May 27, 2009 (the “Filing Requirements”). At 0.5% of a Distribution Revenue Requirement of $17,467,261, the materiality threshold is calculated as being $87,286

REVENUE SUFFICIENCY / DEFICIENCY

	2010 Projection	2009 Projection	Var #	Var %
Utility Income	2,755,964	2,854,873	(98,908)	(3.5%)
Utility Rate Base	64,230,976	59,979,973	4,251,003	7.1%
Indicated Rate of Return	4.29%	4.76%	(0.47%)	(9.9%)
Requested / Approved Rate of Return	7.31%	7.02%	0.29%	4.1%
Sufficiency / (Deficiency) in Return	(3.02%)	(2.26%)	(0.76%)	(33.6%)
Net Revenue Sufficiency / (Deficiency)	(1,939,320)	(1,355,722)	(583,599)	(43.0%)
Provision for PILs/Taxes *	(677,955)		(677,955)	0.0%
Gross Revenue Sufficiency / (Deficiency)	(2,617,275)	(1,355,722)	(1,261,554)	(93.1%)
Deemed Overall Debt Rate	*5.62%*	*5.99%*	*(0.37%)*	*(6.2%)*
Deemed Cost of Debt	*2,164,584*	*2,156,160*	*8,424*	*0.4%*
Utility Income less Deemed Cost of Debt	*591,380*	*698,713*	*(107,332)*	*(15.4%)*
Return On Deemed Equity	*2.30%*	*2.91%*	*(0.61%)*	*(21.0%)*
UTILITY INCOME				
Total Net Revenues	15,697,951	15,779,642	(81,691)	(0.5%)
OM&A Expenses	7,766,218	6,566,288	1,199,930	18.3%
Depreciation & Amortization	4,525,690	4,333,380	192,310	4.4%
Taxes other than PILs / Income Taxes	173,946	246,309	(72,363)	(29.4%)
Total Costs & Expenses	12,465,854	11,145,977	1,319,876	11.8%
Utility Income before Income Taxes / PILs	3,232,097	4,633,665	(1,401,567)	(30.2%)
PILs / Income Taxes	476,133	1,778,792	(1,302,659)	(73.2%)
Utility Income	2,755,964	2,854,873	(98,908)	(3.5%)

REVENUE REQUIREMENT WORK FORM

Attached is the Board’s Revenue Requirement Work Form for this Application.

REVENUE REQUIREMENT WORK FORM

Name of LDC:	Newmarket Tay Power Distribution Ltd.	(1)
File Number:		
Rate Year:	2010	*Version:* 1.0

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

REVENUE REQUIREMENT WORK FORM

Name of LDC: Newmarket Tay Power Distribution Ltd.
File Number:
Rate Year: 2010

		Data Input			(1)
	Application		Adjustments	Per Board Decision	
1 Rate Base					
Gross Fixed Assets (average)	$113,436,986	**(4)**		$113,436,986	
Accumulated Depreciation (average)	($58,936,823)	**(5)**		($58,936,823)	
Allowance for Working Capital:					
Controllable Expenses	$7,940,164	(6)		$7,940,164	
Cost of Power	$56,931,933			$56,931,933	
Working Capital Rate (%)	15.00%			15.00%	
2 Utility Income					
Operating Revenues:					
Distribution Revenue at Current Rates	$14,851,590				
Distribution Revenue at Proposed Rates	$17,468,865				
Other Revenue:					
Specific Service Charges	$366,596				
Late Payment Charges	$194,504				
Other Distribution Revenue	$285,261				
Other Income and Deductions					
Operating Expenses:					
OM+A Expenses	$7,766,218			$7,766,218	
Depreciation/Amortization	$4,525,690			$4,525,690	
Property taxes	$134,056			$134,056	
Capital taxes	$39,890				
Other expenses	($1)			($1)	
3 Taxes/PILs					
Taxable Income:					
Adjustments required to arrive at taxable income	$29,914	**(3)**			
Utility Income Taxes and Rates:					
Income taxes (not grossed up)	$795,535				
Income taxes (grossed up)	$1,154,089				
Capital Taxes	$39,890				
Federal tax (%)	18.00%				
Provincial tax (%)	13.07%				
Income Tax Credits					
4 Capitalization/Cost of Capital					
Capital Structure:					
Long-term debt Capitalization Ratio (%)	56.0%				
Short-term debt Capitalization Ratio (%)	4.0%	**(2)**			**(2)**
Common Equity Capitalization Ratio (%)	40.0%				
Prefered Shares Capitalization Ratio (%)					
				Capital Structure must total 100%	
Cost of Capital					
Long-term debt Cost Rate (%)	5.87%				
Short-term debt Cost Rate (%)	2.07%				
Common Equity Cost Rate (%)	9.85%				
Prefered Shares Cost Rate (%)					

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Newmarket Tay Power Distribution Ltd.
File Number:
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$113,436,986	$ -	$113,436,986
2	Accumulated Depreciation (average)	(3)	($58,936,823)	$ -	($58,936,823)
3	Net Fixed Assets (average)	(3)	$54,500,163	$ -	$54,500,163
4	Allowance for Working Capital	(1)	$9,730,815	$ -	$9,730,815
5	**Total Rate Base**		$64,230,978	$ -	$64,230,978

	(1) Allowance for Working Capital - Derivation				
6	Controllable Expenses		$7,940,164	$ -	$7,940,164
7	Cost of Power		$56,931,933	$ -	$56,931,933
8	Working Capital Base		$64,872,097	$ -	$64,872,097
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$9,730,815	$ -	$9,730,815

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Newmarket Tay Power Distribution Ltd.
File Number:
Rate Year: 2010

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$17,468,865	$ -	$17,468,865
2	Other Revenue	(1)	$846,361	$ -	$846,361
3	Total Operating Revenues		$18,315,226	$ -	$18,315,226
	Operating Expenses:				
4	OM+A Expenses		$7,766,218	$ -	$7,766,218
5	Depreciation/Amortization		$4,525,690	$ -	$4,525,690
6	Property taxes		$134,056	$ -	$134,056
7	Capital taxes		$39,890	$ -	$39,890
8	Other expense		($1)	$ -	($1)
9	Subtotal		$12,465,853	$ -	$12,465,853
10	Deemed Interest Expense		$2,164,584	$ -	$2,164,584
11	Total Expenses (lines 4 to 10)		$14,630,437	$ -	$14,630,437
12	**Utility income before income taxes**		$3,684,789	$ -	$3,684,789
13	Income taxes (grossed-up)		$1,154,089	$ -	$1,154,089
14	**Utility net income**		$2,530,700	$ -	$2,530,700

Notes

(1) **Other Revenues / Revenue Offsets**

	Application	Per Board Decision
Specific Service Charges	$366,596	$366,596
Late Payment Charges	$194,504	$194,504
Other Distribution Revenue	$285,261	$285,261
Other Income and Deductions	$ -	$ -
Total Revenue Offsets	$846,361	$846,361

REVENUE REQUIREMENT WORK FORM

Name of LDC: Newmarket Tay Power Distribution Ltd.
File Number:
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$2,530,701	$2,530,701
2	Adjustments required to arrive at taxable utility income	$29,914	$29,914
3	Taxable income	$2,560,615	$2,560,615
	Calculation of Utility income Taxes		
4	Income taxes	$795,535	$795,535
5	Capital taxes	$39,890	$39,890
6	Total taxes	$835,425	$835,425
7	Gross-up of Income Taxes	$358,554	$358,554
8	Grossed-up Income Taxes	$1,154,089	$1,154,089
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$1,193,979	$1,193,979
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	18.00%	18.00%
12	Provincial tax (%)	13.07%	13.07%
13	Total tax rate (%)	31.07%	31.07%

Notes

REVENUE REQUIREMENT WORK FORM

Name of LDC: Newmarket Tay Power Distribution Ltd.
File Number:
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	($)	Cost Rate (%)	Return ($)
	Application				
	Debt				
1	Long-term Debt	56.00%	$35,969,347	5.87%	$2,111,401
2	Short-term Debt	4.00%	$2,569,239	2.07%	$53,183
3	**Total Debt**	60.00%	$38,538,587	5.62%	$2,164,584
	Equity				
4	Common Equity	40.00%	$25,692,391	9.85%	$2,530,701
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$25,692,391	9.85%	$2,530,701
7	**Total**	100%	$64,230,978	7.31%	$4,695,284

Line No.	Particulars	Capitalization Ratio (%)	($)	Cost Rate (%)	Return
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$35,969,347	5.87%	$2,111,401
9	Short-term Debt	4.00%	$2,569,239	2.07%	$53,183
10	**Total Debt**	60.00%	$38,538,587	5.62%	$2,164,584
	Equity				
11	Common Equity	40.0%	$25,692,391	9.85%	$2,530,701
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$25,692,391	9.85%	$2,530,701
14	**Total**	100%	$64,230,978	7.31%	$4,695,284

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Newmarket Tay Power Distribution Ltd.
File Number:
Rate Year: 2010

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application: At Current Approved Rates	Per Application: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$2,617,275		$2,617,275
2	Distribution Revenue	$14,851,590	$14,851,590	$14,851,590	$14,851,590
3	Other Operating Revenue Offsets - net	$846,361	$846,361	$846,361	$846,361
4	**Total Revenue**	$15,697,951	$18,315,226	$15,697,951	$18,315,226
5	Operating Expenses	$12,465,853	$12,465,853	$12,465,853	$12,465,853
6	Deemed Interest Expense	$2,164,584	$2,164,584	$2,164,584	$2,164,584
	Total Cost and Expenses	$14,630,437	$14,630,437	$14,630,437	$14,630,437
7	**Utility Income Before Income Taxes**	$1,067,514	$3,684,789	$1,067,514	$3,684,789
8	Tax Adjustments to Accounting Income per 2009 PILs	$29,914	$29,914	$29,914	$29,914
9	**Taxable Income**	$1,097,428	$3,714,703	$1,097,428	$3,714,703
10	Income Tax Rate	31.07%	31.07%	31.07%	31.07%
11	**Income Tax on Taxable Income**	$340,950	$1,154,089	$340,950	$1,154,089
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$726,564	$2,530,700	$726,564	$2,530,700
14	**Utility Rate Base**	$64,230,978	$64,230,978	$64,230,978	$64,230,978
	Deemed Equity Portion of Rate Base	$25,692,391	$25,692,391	$25,692,391	$25,692,391
15	Income/Equity Rate Base (%)	2.83%	9.85%	2.83%	9.85%
16	Target Return - Equity on Rate Base	9.85%	9.85%	9.85%	9.85%
	Sufficiency/Deficiency in Return on Equity	-7.02%	0.00%	-7.02%	0.00%
17	Indicated Rate of Return	4.50%	7.31%	4.50%	7.31%
18	Requested Rate of Return on Rate Base	7.31%	7.31%	7.31%	7.31%
19	Sufficiency/Deficiency in Rate of Return	-2.81%	0.00%	-2.81%	0.00%
20	Target Return on Equity	$2,530,701	$2,530,701	$2,530,701	$2,530,701
21	Revenue Sufficiency/Deficiency	$1,804,137	($0)	$1,804,137	($0)
22	**Gross Revenue Sufficiency/Deficiency**	$2,617,275 **(1)**		$2,617,275 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

REVENUE REQUIREMENT WORK FORM

Name of LDC: Newmarket Tay Power Distribution Ltd.
File Number:
Rate Year: 2010

Line No.	Particulars	Revenue Requirement: Application		Revenue Requirement: Per Board Decision	
1	OM&A Expenses	$7,766,218		$7,766,218	
2	Amortization/Depreciation	$4,525,690		$4,525,690	
3	Property Taxes	$134,056		$134,056	
4	Capital Taxes	$39,890		$39,890	
5	Income Taxes (Grossed up)	$1,154,089		$1,154,089	
6	Other Expenses	($1)		($1)	
7	Return				
	Deemed Interest Expense	$2,164,584		$2,164,584	
	Return on Deemed Equity	$2,530,701		$2,530,701	
8	Distribution Revenue Requirement before Revenues	$18,315,226		$18,315,226	
9	Distribution revenue	$17,468,865		$17,468,865	
10	Other revenue	$846,361		$846,361	
11	**Total revenue**	$18,315,226		$18,315,226	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	**(1)**	($0)	**(1)**

Notes

(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Name of LDC: Newmarket Tay Power Distribution Ltd.
File Number:
Rate Year: 2010

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order								
		Monthly Delivery Charge					Total Bill			
			Per Draft	Change				Per Draft	Change	
		Current	Rate Order	$	%		Current	Rate Order	$	%
Residential	**800 kWh/month**			$ -					$ -	
GS < 50kW	**2000** kWh/month			$ -					$ -	

Notes:

Exhibit 2:

RATE BASE

Exhibit 2: Rate Base

Tab 1 (of 6): Overview

RATE BASE OVERVIEW

The rate base used for the purpose of calculating the revenue requirement in this Application follows the definition in the 2006 EDR Handbook as an average of the balances at the beginning and the end of the 2010 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses. The net fixed assets include those Distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The rate base calculation does not include any non-distribution assets. In the working capital portion of rate base, controllable expenses include operations and maintenance, billing and collecting and administration expenses. The Applicant has provided its rate base calculations for the years 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year (Actual) and 2010 Test Year in the table below. The Applicant has calculated its consolidated 2010 rate base to be $64.2M. This forecasted test year rate base is approximately 24.1% higher than the 2006 combined Tay and Newmarket rate base of $51.7M reflecting an annual average increase of about 6% per year.

This increase is largely due to the additions of fixed assets that were required by government, system reliability or customer demand and therefore were beyond the control of The Applicant. The main drivers of the capital spending increase are three major capital projects that have been mandated by government bodies. These three projects account for over 50% ($12.4M) of the capital additions required since 2006. They are responsible for generating $1,430,786 of the Test Year revenue requirement as shown in the following table.

Government Mandated Projects		
Effect on the 2010 Revenue Requirement		
Amortization	$	555,172.72
Cost of Capital	$	662,319.97
PIL's component	$	167,991.68
Lost Interest Revenue	$	45,302.32
Total	$	1,430,786.69

Government Mandated Projects

Holland Junction T.S. – This project was undertaken in order to improve the supply of electricity to the customers in northern York Region. The Ontario Energy Board directed Hydro One, The Applicant and other distributors to construct and connect their systems to Holland T.S. This directive was initiated under proceeding number EB-2005-0315. The Applicant's responsibilities under this initiative, were to construct 4 feeders from the new station to connect to the Newmarket 44kV system and rebuild the pole lines on Bayview Avenue and on Yonge St to the southern boundary to incorporate the Holland feeders into the Newmarket distribution system and accommodate joint use by PowerStream and Hydro One to allow them egress from Armitage TS. The total projected cost of these projects is $3.3M and the completion date is September 2010. To the end of 2009, $2.3M has been spent on these projects leaving Phase 2 of the Holland TS connection and the Yonge St rebuild for completion in 2010. Details of these costs are provided at Exhibit 2, Tab 4, Schedule 4.

Smart Meters – In 2006, The Applicant embarked on an accelerated implementation the government's Smart Meter program and became a industry leader and major contributor to the design and development of this province wide endeavor. The Provincial government (through Ontario Regulations 428/06, 427/06 and 426/06) outlined the requirements of the "smart meter" initiative and The Applicant's service area was identified as a priority implementation area.

By September 2009, all residential smart meters had been installed and all residential customers were being billed on Time-of-Use rates. During this phase-in/testing period, all accounts were being read manually as well as electronically to provide quality control. At that time, the residential smart meters were declared fully operational and manual reads were discontinued. By the end of 2010, it is expected that all remaining eligible customers in Tay and Newmarket will be converted to TOU billing. Once completed, the total cost of this project will be in the amount of $7.1M.

Between 2006 and April of 2009 all costs associated with smart meters and TOU billing in the Newmarket service area were borne by The Applicant. The impact of these expenditures on the Test Year revenue requirement is $1,319,722 which includes operating costs.

Infrastructure Project – In conjunction with its Places to Grow and MoveOntario initiatives, the Government of Ontario through its transportation agency (MetroLinx) has identified Newmarket as a Mobility Hub in the province's Regional Transportation Plan. Thus The Regional Municipality of York (the "Region") in conjunction with MetroLinx has commenced a major Infrastructure Project to improve rapid transportation on Yonge St. and several arteries that connect to it. A more detailed description of this project and the impact it will have on The Applicant's distribution facilities is provided in the major project details section. Work required in the test year involves widening of Davis Drive, which requires the relocation of the Applicant's existing distribution plant. The $1.9M estimated capital spending in the test year is based on the cost of relocating the existing overhead plant within the road allowance provided by the Region. Details of these costs are provided at Exhibit 2, Tab 4, Schedule 4.

Rate Base Trend Table

The following table numerically illustrates the Applicant's rate base:

Rate Base Trend Table
NT Power

Year		Gross Fixed Assets	Accumulated Depreciation	Net Fixed Assets	Average	Allowance for Working Funds	Rate Base	% Change
2006	Additions	5,009,534	(3,649,324)	1,344,878				
	Total	87,181,136	(44,409,368)	42,771,768	42,730,767	9,014,925	51,745,692	
2007	Additions	8,266,568	(3,982,935)	4,283,633	2,182,818	121,916	2,304,734	
	Total	95,447,704	(48,392,303)	47,055,401	44,913,584	9,136,841	54,050,426	4.5%
2008	Additions	7,017,535	(4,089,131)	2,928,404	3,606,019	(37,220)	3,568,799	
	Total	102,465,240	(52,481,434)	49,983,806	48,519,603	9,099,621	57,619,224	6.6%
2009	Additions	5,920,779	(4,333,380)	1,587,399	2,257,902	102,847	2,360,749	
	Total	108,386,019	(56,814,814)	51,571,204	50,777,505	9,202,468	59,979,973	4.1%
2010 Test	Additions	10,383,607	(4,525,690)	5,857,917	3,722,658	528,346	4,251,005	
	Total	118,769,626	(61,340,504)	57,429,122	54,500,163	9,730,814	64,230,978	7.1%
Overall Change since 2006					27.5%	7.9%	24.1%	

RATE BASE VARIANCE ANALYSIS

The Applicant's calculation of the materiality threshold for Net Capital Assets and Working Funds Allowance is consistent with Chapter 2 of the Filing Requirements for Transmission and Distribution Applications. At 0.5% of the Distribution Revenue Requirement of $17,467,261 the threshold amounts to $87,286.

Rate Base Variance Table						
Year	Average Net Fixed Assets		Working Funds Allowance		Rate Base	
	$	%	$	%	$	%
2006	42,730,767		9,014,925		51,745,692	
	2,182,818	5.10%	121,916	1.40%	2,304,734	4.50%
2007	44,913,584		9,136,841		54,050,426	
	3,606,019	8.00%	-37,220	-0.40%	3,568,799	6.60%
2008	48,519,603		9,099,621		57,619,224	
	2,257,902	4.70%	102,847	1.10%	2,360,749	4.10%
2009	50,777,505		9,202,468		59,979,973	
	3,722,658	7.30%	528,346	5.70%	4,251,005	7.10%
2010	54,500,163		9,730,814		64,230,978	
Overall Change 2010 vs 2006	11,769,396	27.50%	715,889	7.90%	12,485,285	24.10%

2010 Test Year vs. 2009 Actual:

The total rate base is expected to be $4,251,005 higher in the 2010 Test Year than in 2009. This increase is attributable to an increase in average net fixed assets of $3,722,658 and a $528,346 increase in the working capital allowance. The increase in fixed assets is due to government mandated projects such as the Leadbeater MS Refurbishment, Boggarttown MS and Eagle Hills rebuild (described at Exhibit 2, Tab 3, Schedule 1). The refurbishment at Leadbeater MS is to reduce the amount of local flooding which has impaired the life of asset and decreased reliability of the MS. The Boggarttown Station is needed to relieve the loading at the existing station in the area and accommodate new load growth. The existing station, Legge MS has exceeded its firm capacity every year since 2006. The Eagle Hills rebuild is scheduled for three phases, the last one to be completed in 2010. The Eagle Hills project is being undertaken because the underground cable systems in the area of the Eagle Hills subdivision are at end of life and thus have increasingly been subject to more than three cable faults per year. The increase in working capital allowance was due to a $2,400,000 total increase in the cost of power and a $1,200,000 increase in OMA. The detailed description of The OMA costs can be found in Exhibit 4. The cost of power increase can be attributed to a increases in the commodity wholesale rate, wholesale transmission network rate and wholesale transmission connection rate. A detailed description of the 2010 capital additions is presented by project in Exhibit 2, Tab 4, Schedule 2, Attachment 1. A detailed calculation of the working capital allowance for the 2010 Test Year can be found at Exhibit 2, Tab 5, Schedule 1, Attachment 1.

2009 Actual vs. 2008 Actual:

The total rate base for the 2009 Actual year is $59,979,973, which represents an increase of $2,360,749 over the 2008 Actual year. This change results in part from an increase in average net assets by $2,257,902. The working capital allowance increased by $102,847 from 2008. The increase in fixed assets is primarily due to the government mandated project of Holland TS as noted above in the Government Mandated Projects section and the Eagle Hills rebuild. The Eagle Hills rebuild is scheduled in three phases, the second phase was completed in 2009. The Eagle Hills project is being undertaken because the underground cable systems in the area of Eagle Hills subdivision are at end of life and thus have increasingly been subject to more than three cable faults per year.

2008 Actual vs. 2007 Actual:

The rate base of $57,619,224 for 2008 Actual increased over 2007 Actual by $3,568,799. This increase is made up of a change in average net assets by $3,606,019 as a result of capital expenditures. The working capital allowance decreased by $37,220.00. The increase in fixed assets is primarily due to the government mandated projects of Holland TS and smart meters/TOU billing (as noted above in the Government Mandated Projects section) and the Eagle Hills rebuild. The Eagle Hills rebuild is scheduled in three phases; the first phase was completed in 2008. The Eagle Hills project is being undertaken because the underground cable systems in the area of the Eagle Hills subdivision are at end of life and thus have increasingly been subject to more than three cable faults per year. The Applicant also replaced two large bucket vehicles throughout 2008.

2007 Actual vs. 2006 Actual:

The rate base of $54,050,426 for 2007 Actual increased over 2006 Actual by $2,304,734. This increase is made up of an increase in average net assets of $2,182,818 and an increase in the working capital allowance of $121,916. The increase in fixed assets is primarily due to the government mandated project of smart meters/TOU billing as noted above in the Government Mandated Projects section.

Exhibit 2: Rate Base

Tab 2 (of 6): Capital Asset Policies

CAPITALIZATION POLICY

The Applicant records capital assets at cost in accordance with Canadian Generally Accepted Accounting Principles as well as guidelines set out by the Ontario Energy Board. All expenditures by the Corporation are classified as either capital or operating expenditures. The intention of these classifications is to consistently allocate costs across accounting periods in a manner that appropriately matches those costs with the related current and future economic benefits. The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation. The Applicant does not capitalize interest on funds for construction. The Applicant's capitalization policy can be described as follows;

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit (will be in use longer than one year) will be capitalized.

- General Plant 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 (i.e. there is a significant increase in the physical output or service capacity; or the useful life of the capital asset is extended) will be capitalized.

- With respect to transportation equipment (e.g. vehicles), all costs associated with putting a vehicle into service are capitalized.

ASSET RETIREMENT POLICY

The Applicant does not currently have a formal asset retirement policy in place but the subject of asset retirement is discussed as part of the exhibit entitled "Asset Management" at Exhibit 2, Tab 4, Schedule 6.

DEPRECIATION POLICY

In accordance with the CICA Handbook and the 2006 EDR handbook The Applicant uses straight line method of amortization.

Amortization

The straight line form of amortization is used as the amortization method for capital assets. The specific rates for amortization vary and are detailed below. For this purpose, The Applicant follows Appendix 2 of the 2006 EDR Handbook.

Tangible assets are recorded as Grouped Assets (sometimes referred to as pooled assets) or Readily Identifiable Assets.

Grouped Assets

Grouped Assets are those assets that by their nature make identification of individual components impractical (e.g. conductors and devices, line transformers, poles and associated fixtures). The following asset classes are grouped assets.

Asset	Account	Grouped or Identifiable	Asset Life
Distribution Lines o/h Poles	1830	Grouped	25 Years
Distribution Lines o/h Cable	1835	Grouped	25 Years
Distribution Lines u/g Conduit	1840	Grouped	25 Years
Distribution Lines u/g Cable	1845	Grouped	25 Years
Services	1855	Grouped	25 Years
Distribution Transformers	1850	Grouped	25 Years
Distribution Meters	1860	Grouped	25 Years
Smart Meters	1860	Grouped	15 Years
Sentinel Lighting Units	1985	Grouped	15 Years
Contributed Capital	1995	Grouped	25 Years

Readily Identifiable Assets

Readily identifiable assets are assets that have a material unit cost and are tracked on an individual unit basis (e.g. computers, office equipment, and rolling stock).

Asset	Account	Grouped or Identifiable	Asset Life
Distribution - Land	1805	Identifiable	Not Depreciated
Distribution - Land Rights	1806	Identifiable	30 Years
Mun Trans Stn<50kv	1820	Identifiable	30 Years
Leasehold Improvements	1910	Identifiable	5 Years
Office Equipment	1915	Identifiable	10 Years
Computer Equipment	1920	Identifiable	5 Years
Computer Software	1925	Identifiable	5 Years
Stores Whse Equipment	1935	Identifiable	5 Years
Rolling Stock Large	1930	Identifiable	8 Years
Rolling Stock Small	1930	Identifiable	5 Years
Misc. Tools & Equip.	1940	Identifiable	10 Years
Measurement & Test Equipment	1945	Identifiable	10 Years
System Supervisory Equip	1980	Identifiable	15 Years

Note: The Applicant has estimated a weighted average life of 7.5 years for its combined fleet of Rolling Stock and uses this life to estimate 2009 actual and 2010 Test Year amortization expense for the class.

CAPITAL CONTRIBUTION POLICY

Capital contributions are calculated in accordance with the Distribution System Code. The Applicant continually expands its distribution system to accommodate customer-driven requests for service or additional power requirements. Each request for power is assessed individually and an economic evaluation is performed to determine whether the future incremental distribution revenue from a system expansion will pay for the capital costs and ongoing maintenance costs of the system expansion. The economic evaluation determines the customer's capital contribution for the equipment, labour and ongoing maintenance costs of the expansion costs. A shortfall in revenue will result in a capital contribution being required from the customer to pay for the cost of the expansion.

Exhibit 2: Rate Base

Tab 3 (of 6): Fixed Assets

GROSS ASSETS

The following tables summarize the Applicant's rate base on a combined basis for both the Tay and Newmarket service (Table #1) and individually (Tables #2 and #3):

Table #1: Rate Base Summary Table - Combined

NT Power

Year		Gross Fixed Assets	Accumulated Depreciation	Net Fixed Assets	Average	Allowance for Working Funds	Rate Base	% Change
2006	Additions	5,009,534	(3,649,324)	1,344,878				
	Total	87,181,136	(44,409,368)	42,771,768	42,730,767	9,014,925	51,745,692	
2007	Additions	8,266,568	(3,982,935)	4,283,633	2,182,818	121,916	2,304,734	
	Total	95,447,704	(48,392,303)	47,055,401	44,913,584	9,136,841	54,050,426	4.5%
2008	Additions	7,017,535	(4,089,131)	2,928,404	3,606,019	(37,220)	3,568,799	
	Total	102,465,240	(52,481,434)	49,983,806	48,519,603	9,099,621	57,619,224	6.6%
2009	Additions	5,920,779	(4,333,380)	1,587,399	2,257,902	102,847	2,360,749	
	Total	108,386,019	(56,814,814)	51,571,204	50,777,505	9,202,468	59,979,973	4.1%
2010 Test	**Additions**	**10,383,607**	**(4,525,690)**	**5,857,917**	**3,722,658**	**528,346**	**4,251,005**	
	Total	**118,769,626**	**(61,340,504)**	**57,429,122**	**54,500,163**	**9,730,814**	**64,230,978**	**7.1%**
Overall Change since 2006					**27.5%**	**7.9%**	**24.1%**	

Table #2: Tay Rate Base Summary Table

Year		Gross Fixed Assets	Accumulated Depreciation	Net Fixed Assets	Average	Allowance for Working Funds	Rate Base
2004 (Approved)	**Total**	**6,813,083**	**(3,830,431)**	**2,982,652**	**2,970,526**	**572,914**	**3,543,440**
2005	**Additions**	104,635	(354,639)	(79,935)	(112,876)	34,528	(78,348)
	Total	6,917,719	(4,185,070)	2,732,649	2,857,650	607,442	3,465,092
2006	**Additions**	316,084	(234,082)	82,002	(84,001)	(3,624)	(87,625)
	Total	7,233,802	(4,419,152)	2,814,651	2,773,650	603,817	3,377,467
2007	**Additions**	763,240	(271,328)	491,912	286,957	2,973	289,930
	Total	7,997,042	(4,690,479)	3,306,563	3,060,607	606,790	3,667,397
2008	**Additions**	450,335	(362,949)	87,386	289,649	52,278	341,926
	Total	8,447,377	(5,053,428)	3,393,948	3,350,256	659,068	4,009,324
2009	**Additions**	389,577	(344,178)	45,399	66,392	(23,940)	42,452
	Total	8,836,954	(5,397,607)	3,439,347	3,416,648	635,128	4,051,776
2010	**Additions**	**525,413**	**(368,171)**	**157,242**	**101,321**	**80,245**	**181,565**
	Total	**9,362,367**	**(5,765,778)**	**3,596,590**	**3,517,969**	**715,373**	**4,233,341**

The average addition to gross fixed assets in the Tay service area from 2007 – 2009 were approximately $534,000/year. The forecasted additions to gross fixed assets in the 2010 Test Year in the Tay service area are approximately $597,000, which is consistent with the $534,000 average.

Table #3: Newmarket Rate Base Summary

Year		Gross Fixed Assets	Accumulated Depreciation	Net Fixed Assets	Average	Allowance for Working Funds	Rate Base
2006	**Additions**	4,693,450	(3,415,243)	1,262,876			
	Total	79,947,334	(39,990,216)	39,957,117	39,957,117	8,411,108	48,368,225
2007	**Additions**	7,503,328	(3,711,607)	3,791,721	1,895,860	118,943	2,014,804
	Total	87,450,662	(43,701,824)	43,748,838	41,852,978	8,530,051	50,383,029
2008	**Additions**	6,567,201	(3,726,182)	2,841,019	3,316,370	(89,498)	3,226,872
	Total	94,017,863	(47,428,006)	46,589,857	45,169,348	8,440,553	53,609,901
2009	**Additions**	5,531,202	(3,989,202)	1,542,000	2,191,509	126,787	2,318,296
	Total	99,549,065	(51,417,208)	48,131,857	47,360,857	8,567,340	55,928,197
2010	**Additions**	**9,858,194**	**(4,157,519)**	**5,700,675**	**3,621,337**	**448,102**	**4,069,439**
	Total	**109,407,258**	**(55,574,726)**	**53,832,532**	**50,982,194**	**9,015,442**	**59,997,636**

The average of additions to gross fixed assets in the Newmarket service area from 2007–2009 was approximately $6,534,000/year. The forecasted additions to gross fixed assets in the 2010 Test Year in the Newmarket service area are approximately $9,858,000. Although the capital addition increase in 2010 relative to previous years appears to be significant, the Applicant’s regular capital additions from 2007 to 2010 remains relatively constant. In order to compare Test Year capital additions to previous years’ capital additions, capital spending should be normalized to address the following: (i) government projects; and (ii) the Leadbeater MS delay, both of which are discussed below.

i) Government Projects:

From 2007 to 2010, but particularly in 2010, the Applicant was required to partake in large capital projects driven by Government bodies that fall outside the Applicant's regular capital spending activities (the "Government Projects"). The Government Projects are:

- Job # CP212 - Holland Junction T.S. Tielines
- Job # CP193 – Bayview Ave. tie-line to PowerStream
- Job # CP198 – Yong St./ Davis Drive Infrastructure Project
- Job # CP276 & TP276 – Smart Meter Implementation

Detailed descriptions of these projects are set out at Exhibit 2, Tab 4, Schedule 3 and Exhibit 2, Tab 4, Schedule 4 (please refer to the corresponding Job #). The following tables normalize the Applicant's capital additions by removing the capital cost of Government Projects. Table #4 sets out the Applicant's total annual capital additions, Table #5 sets out the costs of the Government Projects, and Table #6 sets out the total annual capital additions without the Government Projects.

Table #4: Total Capital Additions

	2007	**2008**	**2009**	**2010**
Land & Land Rights	51,481	756,333	156,931	0
Buildings	2,743	0	65,624	0
Mun Trans Stn<50kv	171,053	412,930	2,412	1,429,792
Distribution Lines	3,662,808	4,111,673	5,795,269	7,473,734
Distribution Transformers	1,025,697	993,043	992,068	1,489,888
Distribution Meters	3,688,295	1,309,088	767,550	2,076,915
Vehicles	141,250	725,821	385,000	115,000
Other Equipment	136,728	180,654	179,770	137,140
Other Fixed Assets	376,979	107,996	202,500	355,200
Contributed Capital	-1,421,423	-1,570,253	-2,115,941	-2,694,061
Total	**7,835,609**	**7,027,285**	6,431,182	**10,383,607**

Table #5: Government Projects

	2007	2008	2009	2010
CP 212 Holland Junction TS				
Land & Land Rights	0	222,075	23,000	0
Distribution Lines	0	493,086	1,298,939	868,039
Distribution Meters	0	0	53,000	0
Total Job	**0**	**715,161**	**1,374,939**	**868,039**
CP 193 Bayview Avenue Feeders to PowerStream				
Distribution Lines	0	0	577,428	0
Contributed Capital	0	0	-130,078	0
Total Job	**0**	**0**	**447,350**	**0**
CP287 Yonge St Feeders to Hydro One				
Distribution Lines	0	0	0	221,440
Contributed Capital	0	0	0	(80,000)
Total Job	**0**	**0**	**0**	**141,440**
CP 276 & TP 276 Smart Meter Program				
Distribution Meters	3,296,111	765,566	623,872	2,027,551
Total Job		**765,566**	**623,872**	**2,027,551**
CP 198 VIVA Infrastructure Project				
Distribution Lines	0	0	10,823	2,164,765
Distribution Transformers	0	0	0	660,229
Contributed Capital	0	0	0	-893,995
Total Job		0	**10,823**	**1,930,999**
Total Government Projects	**3,296,111**	**1,480,727**	**2,456,984**	**4,968,029**

Table #6: Capital Additions w/o Government Projects

	2007	2008	2009	2010
Land & Land Rights	51,481	534,258	133,931	0
Buildings	2,743	0	65,624	0
Mun Trans Stn<50kv	171,053	412,930	2,412	1,429,792
Distribution Lines	3,662,808	3,618,587	3,908,902	4,219,490
Distribution Transformers	1,025,697	993,043	992,068	829,659
Distribution Meters	392,184	543,523	90,678	49,364
Vehicles	141,250	725,821	385,000	115,000
Other Equipment	136,728	180,654	179,770	137,140
Other Fixed Assets	376,979	107,996	202,500	355,200
Contributed Capital	-1,421,423	-1,570,253	-1,985,863	-1,720,066
Total Non-Government Jobs	**4,539,499**	**5,546,559**	**3,975,021**	**5,415,578**

It is apparent from Table #6 that without the Government Projects, the Applicant's capital additions in the test year is in-line previous years' spending.

ii) The Leadbeater MS Delay

The second cause for the increase in 2010 capital spending is the delay of the complete refurbishment of the Leadbeater MS (Project #CP 214). This project was originally scheduled for 2009, but due to delays in procuring equipment, the project will be delayed until 2010. As such, $730,222 has been included in the 2010 capital budget instead of the 2009 capital budget as originally planned.

If, for trend analysis purposes, the Applicant's capital spending were normalized to both: (i) remove the Government Projects; and (ii) shift the costs of the Leadbeater MS refurbishment from 2010 to 2009 as it had been originally planned, the Applicant's regular annual capital spending would be as follows:

Table #7: Capital Additions - w/o Government Jobs and Shifted Leadbeater MS

CP214 Leadbeater DS complete refurbishment				
Mun Trans Stn<50kv			709,637	-709,637
Total Normalizied	4,539,499	5,546,559	4,684,658	4,705,941

Based on the data in Table #7, the Applicant's regular capital spending from 2007 to 2010 remains relatively constant.

Gross Asset Variances Table

The following table sets out the Applicant's gross asset variances by account from 2008 to 2010. Explanations for variances that exceed materiality are below the table.

Class	Account #	2010	2009	Variance	%	2009	2008	Variance	%
Distribution - Land	1805	3,128,319	3,128,319	0	0.00%	3,128,319	3,104,515	23,804	0.76%
Distribution - Land Rights	1806	589,802	589,802	0	0.00%	589,802	463,812	125,990	21.36%
Mun Trans Stn<50kv	1820	10,309,238	8,879,447	1,429,792	13.87%	8,879,447	8,879,447	(0)	0.00%
Distribution Lines o/h Poles	1830	17,187,234	14,924,554	2,262,680	13.16%	14,924,554	14,113,004	811,550	5.44%
Distribution Lines o/h Cable	1835	19,404,712	17,085,100	2,319,612	11.95%	17,085,100	16,256,387	828,713	4.85%
Distribution Lines u/g Conduit	1840	8,969,352	8,431,458	537,894	6.00%	8,431,458	7,582,427	849,032	10.07%
Distribution Lines u/g Cable	1845	26,949,346	25,270,269	1,679,077	6.23%	25,270,269	23,658,386	1,611,883	6.38%
Services	1855	8,491,023	7,816,552	674,471	7.94%	7,816,552	6,519,311	1,297,241	16.60%
Distribution Transformers	1850	18,748,283	17,258,394	1,489,888	7.95%	17,258,394	16,246,035	1,012,359	5.87%
Distribution Meters	1860	7,931,881	7,882,517	49,364	0.62%	7,882,517	7,704,477	178,040	2.26%
Smart Meters	1860	7,371,855	5,344,304	2,027,551	27.50%	5,344,304	4,871,019	473,285	8.86%
Leasehold Improvements	1910	805,826	710,826	95,000	11.79%	710,826	456,691	254,135	35.75%
Office Equipment	1915	383,030	370,990	12,040	3.14%	370,990	352,373	18,617	5.02%
Computer Equipment	1920	909,833	864,733	45,100	4.96%	864,733	838,637	26,096	3.02%
Computer Software	1925	1,763,997	1,503,797	260,200	14.75%	1,503,797	1,465,482	38,316	2.55%
Stores Whse Equipment	1935	151,247	151,247	0	0.00%	151,247	151,247	0	0.00%
Rolling Stock & Equip.	1930	4,333,188	4,218,188	115,000	2.65%	4,218,188	4,003,225	214,963	5.10%
Misc. Tools & Equip.	1940	575,753	530,753	45,000	7.82%	530,753	511,791	18,962	3.57%
Measurement & Test Equip	1945	137,535	102,535	35,000	25.45%	102,535	102,535	0	0.00%
System Supervisory Equip	1980	742,641	742,641	0	0.00%	742,641	742,641	0	0.00%
Buildings	1908	297,912	297,912	0	0.00%	297,912	279,020	18,892	6.34%
Contributed Capital	1995	(20,553,217)	(17,859,155)	(2,694,061)	13.11%	(17,859,155)	(15,837,221)	(2,021,935)	11.32%
Total Fixed Assets		118,628,790	108,245,183	10,383,607	8.75%	108,245,183	102,465,240	5,779,943	5.34%

Class	Account #	2008	2007	Variance	%	2007	2006	Variance	%
Distribution - Land	1805	3,104,515	2,570,257	534,258	17.21%	2,570,257	2,518,776	51,481	2.00%
Distribution - Land Rights	1806	463,812	241,737	222,075	47.88%	241,737	241,737	0	0.00%
Mun Trans Stn<50kv	1820	8,879,447	8,466,517	412,930	4.65%	8,466,517	8,295,464	171,053	2.02%
Distribution Lines o/h Poles	1830	14,113,004	13,037,010	1,075,994	7.62%	13,037,010	12,318,296	718,714	5.51%
Distribution Lines o/h Cable	1835	16,256,387	15,633,746	622,641	3.83%	15,633,746	15,045,191	588,555	3.76%
Distribution Lines u/g Conduit	1840	7,582,427	7,141,579	440,848	5.81%	7,141,579	6,751,312	390,267	5.46%
Distribution Lines u/g Cable	1845	23,658,386	22,778,602	879,783	3.72%	22,778,602	22,010,929	767,674	3.37%
Services	1855	6,519,311	5,426,903	1,092,407	16.76%	5,426,903	4,229,306	1,197,598	22.07%
Distribution Transformers	1850	16,246,035	15,252,992	993,043	6.11%	15,252,992	14,227,295	1,025,697	6.72%
Distribution Meters	1860	7,704,477	7,254,255	450,222	5.84%	7,254,255	7,156,904	97,351	1.34%
Smart Meters	1860	4,871,019	4,021,903	849,116	17.43%	4,021,903	0	4,021,903	100.00%
Leasehold Improvements	1910	456,691	419,236	37,456	8.20%	419,236	390,216	29,019	6.92%
Office Equipment	1915	352,373	325,521	26,852	7.62%	325,521	286,455	39,066	12.00%
Computer Equipment	1920	838,637	723,125	115,512	13.77%	723,125	652,447	70,678	9.77%
Computer Software	1925	1,465,482	1,398,547	66,934	4.57%	1,398,547	1,050,588	347,960	24.88%
Stores Whse Equipment	1935	151,247	148,483	2,764	1.83%	148,483	147,256	1,227	0.83%
Rolling Stock & Equip.	1930	4,003,225	3,277,404	725,821	18.13%	3,277,404	3,136,154	141,250	4.31%
Misc. Tools & Equip.	1940	511,791	476,265	35,526	6.94%	476,265	469,035	7,230	1.52%
Measurement & Test Equip	1945	102,535	102,535	0	0.00%	102,535	88,488	14,047	13.70%
System Supervisory Equip	1980	742,641	739,035	3,606	0.49%	739,035	734,556	4,479	0.61%
Buildings	1908	279,020	279,020	0	0.00%	279,020	276,277	2,743	0.98%
Contributed Capital	1995	(15,837,221)	(14,266,967)	(1,570,253)	9.91%	(14,266,967)	(12,845,544)	(1,421,423)	9.96%
Total Fixed Assets		102,465,240	95,447,704	7,017,536	6.85%	95,447,704	87,181,136	8,266,568	8.66%

Land Rights 1806 – In 2008 The Applicant purchased land rights to egress from Holland TS Capital Job (“CP”) 122 for $125,990. There have been no significant expenditures since then.

Mun Trans Stn<50 KV-1820 - The Applicant normally spends less than $500,000 per annum on stations. In 2010, The Applicant is expecting to spend over $1,400,000 on two stations: the Leadbeater MS and the Boggarttown MS. The Leadbeater MS is a refurbishment of an existing station while the Boggartown MS project is a new station that is required to relieve the overloading in area due to demand growth within the service territory.

Distribution Lines o/h Poles 1830 - The Applicant on an annual basis spends roughly $1,000,000 on distribution lines and overhead poles. For 2010, the amount required to maintain service quality has more than doubled to $2,200,000. This higher than normal increase is necessary to pay the additional $1,000,000 expected expenditure for Capital Project 198 (Government Mandated Projects- VIVA Infrastructure Project).

Distribution Lines o/h Cable Account # 1835 - The Applicant on an annual basis spends $650,000 in distribution lines and cable. For 2010, the expected expenditure is $2,300,000. A significant portion ($1,000,000) of this increase is required to cover the Capital Project 198 (Government Mandated Projects- VIVA Infrastructure Project). An additional $400,000 will be spent on the Holland TS and another $200,000 is required for the replacement of end of life assets within the Tay service area.

Distribution Lines u/g Conduit Account # 1840- The Applicant on an annual basis spends $500,000 on distribution lines u/g conduit. In 2009 The Applicant spent approximately $850,000. The increase from the average was partially due to The Applicant spending $122,000 related to Holland TS CP 122 (Government Mandated Jobs- Holland Junction TS). The remainder was due to a decrease in new connections compared to prior years, therefore the corresponding services expenditures have also decreased.

Distribution Lines u/g Cable Account # 1845 - Between 2007 and 2008 The Applicant spent on average of $800,000 on this account and between 2009 and 2010 this amount had doubled to $1,600,000 per year. The primary driver for this significant increase is the Eagle Hills rebuild (CP 199). The Eagle Hills project is being undertaken because the underground cable systems in the area are at the end of their useful life and thus have increasingly been subject to cable faults and service disruptions. This project is being completed over three years 2008, 2009 and 2010. The majority of the costs are in 2009 and 2010.

Services Account # 1855 - The Applicant on average expends over $1,000,000 per year on services. For 2010 The Applicant is forecasting expenditures of $674,000. These expenditures are directly related to the number of new connections serviced. In 2010, The Applicant expects a decrease in new connections compared to prior years, therefore the corresponding services expenditures have also decreased.

Distribution Transformers Account # 1850 - The Applicant on an annual basis spends $1,000,000 for transformers. For 2010, the forecasted amount is approximately $1,500,000, representing an increase of $500,000. This increase is due to additional $500,000 expenditure on Capital Project 198 (Government Mandated Projects- VIVA Infrastructure Project).

Distribution Meters Account # 1860 - In 2008 The Applicant purchased and installed a new wholesale meter point at Armitage TS for $450,000.

Smart Meters Account # 1860 - The Provincial Government (through Ontario Regulations 428/06, 427/06 and 426/06) outlined the "smart meter" initiative and The Applicant has been identified Newmarket as a priority implementation area. In 2007, The Applicant purchased and installed over 26,000 residential Smart Meters throughout its service territory and incurred a cost of over $4,000,000. By 2009 installation was complete and The Applicant started to implement Time of Use billing for all eligible customers. The Applicant continued to incur conversion and start up costs. During 2010, Smart Meters will be deployed to all GS<50 customers. The Applicant expects to incur costs in access of $2,000,000 to purchase, install and implement TOU billing for the GS<50 class in 2010.

Computer software Account # 1925 - In 2007 The Applicant incurred software costs of approximately $350,000. These costs included $150,000 in software and conversion cost for converting the former Tay Hydro GIS to Newmarket Hydro's CIS. Also The Applicant incurred over $100,000 conversion costs to upgrade its financial software. For the 2010 forecast The Applicant is expecting to incur over $200,000 for a GIS system. The Applicant requires a GIS system to contain and centralize its entire asset data and to enable and improve asset management processes. The Applicant will use GIS to help support and control processes such as inspection, maintenance, capital planning, inventory, tracking and application of Electric Safety Authority requirements and safety bulletins, and financial management that affect the assets. A GIS will also integrate these processes by providing a common base of asset data and an efficient means for the exchange of information across functional departments and with 3rd party entities e.g. "one-call" companies for cable locate services.

The Applicant needs inspection, maintenance and asset records to be readily available to operating, engineering, and field personnel and GIS will facilitate ready access to inspection records for any given asset, seeing spatial relationships with respect to outages, past inspection activities, asset age and cost and condition.

Rolling Stock and Equipment Account # 1930 - In the 2008 The Applicant incurred over $725,000 in new vehicle costs. The majority of these costs were for a new double bucket truck and a new Radial Boom Derrick.

Contributed Capital Account # 1995 - The Applicant on an annual basis collects $1,500,000 in contributed capital. For 2010 the amount has increased to $2,700,000. This increase is due to additional $900,000 expected as a capital contribution for CP 198 (Government Mandated Projects- VIVA Infrastructure Project).

In 2009 The Applicant collected approximately $2,000,000, a increase of $500,000. The majority of this increase was the result of a capital contribution from Powerstream to accommodate the egress from Armitage MS as part of the Holland Junction TS CP 122. (Government Mandated Projects- Holland TS).

CAPITAL ASSET AMORTIZATION

The table at the following page provides the continuity for Gross Fixed Asset Values from 2006 to 2009.

Fixed Asset Continuity Schedule - NT Power

Class	Account #	2006	2007			2008		2009			2010 Test	
			Additions	Write Offs	Actual	Additions	Actual	Additions	Write Offs	Actual	Additions	Projected
Distribution - Land	**1805**	2,518,776	51,571		2,570,257	534,168	3,104,515	23,804	0	3,128,319	0	3,128,319
Distribution - Land Rights	**1806**	241,737	0		241,737	222,075	463,812	125,990	0	589,802	0	589,802
Mun Trans Stn<50kv	**1820**	8,295,464	171,053		8,466,517	412,930	8,879,447	(0)	0	8,879,447	1,429,792	10,309,238
Distribution Lines o/h Poles	**1830**	12,318,296	718,714		13,037,010	1,075,994	14,113,004	811,550	0	14,924,554	2,262,680	17,187,234
Distribution Lines o/h Cable	**1835**	15,045,191	588,555		15,633,746	622,641	16,256,387	828,713	0	17,085,100	2,319,612	19,404,712
Distribution Lines u/g Conduit	**1840**	6,751,312	390,267		7,141,579	440,848	7,582,427	849,032	0	8,431,458	537,894	8,969,352
Distribution Lines u/g Cable	**1845**	22,010,929	767,674		22,778,602	879,783	23,658,386	1,611,883	0	25,270,269	1,679,077	26,949,346
Services	**1855**	4,229,306	1,197,598		5,426,903	1,092,407	6,519,311	1,297,241	0	7,816,552	674,471	8,491,023
Distribution Transformers	**1850**	14,227,295	1,025,697		15,252,992	993,043	16,246,035	1,012,859	(500)	17,258,394	1,489,888	18,748,283
Distribution Meters	**1860**	7,156,904	97,351		7,254,255	450,222	7,704,477	179,862	(1,821)	7,882,517	49,364	7,931,881
Smart Meters	**1860**	0	4,021,903		4,021,903	849,116	4,871,019	473,285	0	5,344,304	2,027,551	7,371,855
Leasehold Improvements	**1910**	390,216	29,019		419,236	37,456	456,691	254,135	0	710,826	95,000	805,826
Office Equipment	**1915**	286,455	39,066		325,521	26,852	352,373	19,035	(418)	370,990	12,040	383,030
Computer Equipment	**1920**	652,447	70,678		723,125	115,512	838,637	26,096	0	864,733	45,100	909,833
Computer Software	**1925**	1,050,588	347,960		1,398,547	66,934	1,465,482	38,316	0	1,503,797	260,200	1,763,997
Stores Whse Equipment	**1935**	147,256	1,227		148,483	2,764	151,247	0	0	151,247	0	151,247
Rolling Stock & Equip.	**1930**	3,136,154	141,250		3,277,404	725,821	4,003,225	346,763	(131,800)	4,218,188	115,000	4,333,188
Misc. Tools & Equip.	**1940**	469,035	16,627	(9,397)	476,265	35,526	511,791	25,258	(6,296)	530,753	45,000	575,753
Measurement & Test Equip	**1945**	88,488	14,047		102,535	0	102,535	0	0	102,535	35,000	137,535
System Supervisory Equip	**1980**	734,556	4,479		739,035	3,606	742,641	0	0	742,641	0	742,641
Buildings	**1908**	276,277	2,743		279,020	0	279,020	18,892	0	297,912	0	297,912
Contributed Capital	**1995**	(12,845,544)	(1,421,423)		(14,266,967)	(1,570,253)	(15,837,221)	(2,021,935)	0	(17,859,155)	(2,694,061)	(20,553,217)
Total Fixed Assets		**87,181,136**	**8,276,055**	**(9,397)**	**95,447,704**	**7,017,446**	**102,465,240**	**5,920,779**	**(140,836)**	**108,245,183**	**10,383,607**	**118,628,790**
Accumulated Amortization		(44,409,368)	(3,982,935)		(48,392,303)	(4,089,131)	(52,481,434)	(4,333,380)	140,836	(56,673,979)	(4,525,690)	(61,199,668)
Net Fixed Assets		**42,771,768**	**4,293,120**	**(9,397)**	**47,055,401**	**2,928,315**	**49,983,806**	**1,587,399**	**0**	**51,571,204**	**5,857,917**	**57,429,122**
Average Net Fixed Assets					**44,913,584**		**48,519,603**			**50,777,505**		**54,500,163**

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Exhibit 2: Rate Base

Tab 4 (of 6): Capital Plan

SUMMARY OF HISTORICAL CAPITAL EXPENDITURES

This section provides an analysis of the Applicant Capital Plan Projects. The analysis covers 2009 Actuals and 2010 Test Year.

The Applicant has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. The Applicant continuously completes inspections throughout the year while completing maintenance on the distribution system.

The reliability indices are recorded and monitored on an annual basis as demonstrated at Exhibit 2, Tab 6, Schedule 1. They are used to assess the asset condition which impacts the capital budgeting process. The Applicant has an obligation to serve new growth within the service area in a timely and cost effective way. In order to fulfill this obligation, the Applicant identifies all potential areas where new growth may occur, while recognizing that the actual timing of each possible new development is uncertain. Although growth has an impact on capital expenditures, reliability and safety are the main components taken into account.

Their capital budget reflects the level of growth that we anticipate based on the overall rate of development in the service area in recent years, anticipated economic conditions and management judgment.

The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects.

As previously mentioned, The Applicant is obligated to fulfill government mandated project that contribute to the overall increase in capital expenditures.

Each year The Applicant looks at other plant, equipment and vehicles, along with the distribution system and determines the needs to ensure only those capital investments that are required to ensure a safe and reliable operation of The Applicant's distribution system are made.

Analysis of Major Capital Expenditures:

The following section of The Application presents a description of the program classification as well as a breakdown of major capital projects for 2009 Actuals and projected capital projects for 2010 Test Year.

PROJECT/PROGRAM CLASSIFICATIONS

GROWTH DRIVEN:

These are projects that the Applicant undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and the Applicant's Conditions of Service. Activities include all overhead and underground works to connect new customers or service upgrades, connection and inspection of new subdivisions and relocating system plant for roadway reconstruction work. Capital contributions toward the cost of these projects are collected by the Applicant in accordance with the DSC and the provisions of its Conditions of Service. Such projects involved load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system.

Projects can take the form of new or upgraded feeders, transformers or transformer stations.

RELIABILITY

The DSC requires an LDC to maintain its distribution system in good working condition, as follows:

"4.4.1. A distributor shall maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electricity service on both a short-term and long-term basis."

The following components are regular activities undertaken by the Applicant to maintain reliability and promote safety.

OVERHEAD LINES

Tree Trimming:

Vegetation and Right of Way control is a requirement under the Minimum Inspection Requirements of the DSC and good utility practice. Where overhead hydro lines are in the proximity to trees, regular trimming is required to prevent vegetation form contacting energized lines and inflicting:

- Interruption of power due to short circuit to ground or between phases
- Damage to conductors, hardware and poles
- Danger to persons and property within the vicinity due to falling conductors, hardware, poles and trees
- Danger of electric shock potential from electricity energizing vegetation

In an effort of mitigating direct contact between trees and distribution assets, tree trimming is conducted on a one year cycle. The Applicant's contractor patrols the overhead lines and where tree trimming is needed the contractor will proceed with the necessary clearing.

During the patrol process, the following potential hazards are also examined:

Conductors and Cables

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Insulation fraying on secondary especially open-wire

Poles/Supports/ Cross arms

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Pole inspection is a requirement under the Minimum Inspection Requirements of the Distribution System Code as good utility practice. The Applicant conducts pole inspections annually to determine when poles need to be replaced.

Pole Replacements are undertaken for the following different reasons:

- Structural damage
- Taller or different class of pole required
- Health and safety hazard to the public and employees
- Pole damaged
- Line rebuilds
- ESA compliance

Hardware and Attachments

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Switches

The Applicant meets the switch inspection requirements under the Minimum Inspection Requirements of the DSC. Switches are devices that allow or disallow the conductivity of high voltage conductors. They are available in single phase solid or fused configurations and three phase applications involving load break and air break. Fused cut-outs accept different sizes of fuses, which are used for the protection of lines, equipment or transformers from main feeder amperages. Fused switches (cutouts) are inspected during yearly patrol process.

Switch Replacements are undertaken for the following reasons:

- Mechanical or electrical failure
- Vehicle accidents, lightning strikes
- New customer requirements
- Line rebuilds or circuit reconfigurations
- ESA compliance

Reclosures

As required under the Minimum Inspection Requirements of the DSC. The Applicant inspects and tests reclosures regularly and oil samples are taken on a yearly basis.

Transformers

Transformer inspection is performed as required under the Minimum Inspection Requirements of the DSC with visual inspections being conducted on an annual cycle basis to check for general appearance, loose wires, birds or animal nests.

UNDERGROUND LINES

Switching apparatus

Every 3 years, switching cubicles are visually inspected in accordance with the Minimum Inspection Requirements in the DSC.

Primary Cables

Underground primary cable inspection is conducted annually by visually examining the riser poles with respect to cable, cable guards, terminators and arrestors

Secondary Services

Similarly, with respect to underground secondary services, riser poles are examined yearly with a visual check of cable, cable guards and connections.

Substations

Substation investments are undertaken to improve or maintain reliability to large numbers of customers and to maintain security and safety at the substations. Age and condition of the transformers are also a major factor in this decision.

REGULATORY AND 3RD PARTY DRIVEN

The projects are mainly driven and mandated by government authorities and are beyond The Applicant’s control.

INTERNALLY DRIVEN - Fleet

The Applicant's fleet is an integral tool for providing safe and reliable service for the rapid response to various contingency situations occurring in its distribution service areas. In order to respond to trouble calls efficiently, and to avoid downtime and delays in maintenance and construction, the Applicant ensures it has a safe, reliable and well-maintained fleet.

FIXED ASSET EXPENDITURES BY PROJECT

The following Tables show the capital expenditures by Project and by account for both service areas for 2009 Actual and 2010 Test Years. All capital expenditures will be in service (used and useful) by the end of their respective year. Detailed write-ups for each Project are at Exhibit 2, Tab 4, Schedule 4.

2009 Actual Expenditures - Newmarket

Grand Total		**Units**	**Job #**	**USoA**	**5,531,202**
Customer Additions					
Residential	Single Family	494	CP 216		
	Townhomes	150			
O/H Poles				1830	19,517
O/H Conductor				1835	26,517
U/G Conduit				1840	300,228
U/G Conductor				1845	786,141
Transformers				1850	755,396
Services				1855	1,273,471
Meters				1860	32,027
Contributed Capital				1950	(2,021,935)
Total Job					1,171,364
Commercial/Industrial		3	CP 217		
O/H Poles				1830	12,999
O/H Conductor				1835	19,999
U/G Conduit				1840	2,316
U/G Conductor				1845	3,265

Transformers			1850	37,290
Meters			1860	9,485
Total Job				85,354
Total Customer Additions				**1,256,718**
Overhead Line Additions, Rebuilds				
Holland TS		CP 122		
TS feeder egress from HONI Holland Landing to Greenlane/Bathurst area. 4 feeders (approx 99 poles)				
Land			1805	23,804
Land Rights			1806	125,990
O/H Poles			1830	244,720
O/H Conductor			1835	432,901
U/G Conduit			1840	122,377
U/G Conductor			1845	112,476
Wholesale Meters			1860	125,683
Total Job				1,187,951
Bayview pole line rebuild Mulock to Aurora townline to integrate new feeders from Holland TS abd accommodate Powerstream egress from Armitage TS		CP 193		
O/H Poles			1830	461,191
O/H Conductor			1835	267,773
U/G Conductor			1845	68,863
Contributed Capital			1950	(330,641)
Total Job				467,186
M23 riser pole & cable replacement at Armitage TS		CP 215		
U/G Conduit			1840	15,218
U/G Conductor			1845	60,063

Total Job				75,281
Region Road Authority relocation north of Mulock on Bathurst		CP 156		
O/H Poles			1830	1,770
O/H Conductor			1835	2,105
Contributed Capital			1950	(1,000)
Total Job				2,876
Bathurst from Mulock to Newmarket/Aurora Town Boundary (Bathurst s/o Mulock relocation due to YR road widening)		CP102		
O/H Poles			1830	29,445
O/H Conductor			1835	29,445
Total Job				58,891
Rebuild residential overhead pole line in EG Heights - Sheldon & Newbury due to end of life		CP211		
O/H Poles			1830	32,616
O/H Conductor			1835	32,616
Total Job				65,232
Total Overhead Line Additions, Rebuilds				**1,857,416**
Underground Line Additions, Rebuilds				
Eagle Hills Ph 2 - Replace end of life underground system	84 lots	CP 199		
U/G Conduit			1840	269,712
U/G Conductor			1845	550,956
Transformers			1850	82,380
Total Job				903,047
Sutherland secondary rearrangement 2 services		CP 223		
U/G Conduit			1840	4,431
U/G Conductor			1845	17,725
Total Job				22,156

Viva Yonge & Davis Dr. underground 44kV study		CP 198		
			1840	2,353
			1845	9,412
Total Job				11,765
Total Underground Line Additions, Rebuilds				**936,968**
Blanket Jobs				
Replace end of life transformers	15	CP 218	1850	131,098
Faulted circuit indicators (old Wildwood area; various locations)	250	CP 099	1845	19,063
Alduti/Omni Rupter Switches - Replacement	1	CP 219	1835	57,612
OH Line - Pole replacement program	30	CP 220	1830	61,955
Miscellaneous Underground Capital		CP 222	1840	20,485
Miscellaneous Underground Capital		CP 222	1845	66,358
Wholesale metering	2	CI 18610	1860	2,027
Total Blanket Jobs				**358,597**
Metering				
Instrument Transformers (PT's) - Replacements	36		1860	3,077
Instrument Transformers (CT's) - Replacements	36		1860	3,077
Self Contained Demand (polyphase) Meter Replacements	7		1860	1,994
Meter Test blocks	30		1860	2,137
Smart Meters - Testing etc			1860	387,268
Total Metering				**397,553**
Leasehold Improvements				
Front Entrance Upgrades - Improve Customer Access		CP 221	1910	8,820

Security System			1910	62,478
Floor - Customer Service			1910	166,827
HVAC 590 Steven Court -tension room heater relocation			1910	8,676
Other			1910	7,334
Total Leasehold Improvements				**254,135**
Major Tools & Instruments				
Lines Dept - Overhead Miscellaneous Tools			1940	10,925
Lines Dept - Miscellaneous Underground Tools			1940	7,970
Shop Tools			1940	2,109
Total Major Tools & Instruments				**21,004**
Vehicles and Equipment				
Replacement Dump truck vehicle #120			1930	76,501
Replacement Single Bucket #310			1930	270,262
			1930	0
Total Vehicles and Equipment				**346,763**
Computer Hardware				
Replacement Workstations			1920	9,447
Upgrade Network Performance			1920	9,493
Workstations			1920	6,956
Total Computer Hardware				**25,896**
Computer Software				
Autocad Upgrade			1925	12,739
Upgrade Network Performance			1925	10,249
Miscellaneous Software			1925	8,232
Total Computer Hardware				**31,220**
Office Equipment				
New Workstations				32,135

Miscellaneous				12,796
Total Office Equipment				**44,931**

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Tay 2009 Capital Budget Summary					
		Units	**Job #**	**USoA**	**Total $**
Grand Totals					**389,577**
Customer Additions					
Residential	Single Family	8	TP 216		
Commercial/Industrial		3	TP 217		
Underground conduit				1840	2,033
Underground conductor				1845	15,018
Services				1855	23,771
Transformers				1850	0
Distribution Meters				1860	354
Contributed Capital to be Amort.				1950	0
Total Customer Additions					**41,175**
Overhead Line Additions, Rebuilds					
Many power lines in the Tay service territory are in need of replacement. Five of these will be completed over the 2009 to 2010 period:					
Port McNicoll					
Armstrong & Davidson -end of life			TP007		
Overhead Conductor				1835	147,247
Overhead Poles				1830	35,357
Job Total					182,604
Waubaushene					
Percy St			TP006		
Brown's Line			TP009		
Overhead Conductor				1835	23,092

Total Overhead Line Additions, Rebuilds			**205,696**
Underground Line Additions, Rebuilds			
Shoreline protection & identification at mainland & Island			
ESA identified the need to protect submarine cable where it is exposed at mainland & island			
Underground conductor	TP 001	1845	**12,422**
Blanket Jobs			
Replace end of life tranformers	TI18500	1850	6,696
Smart Meters		1860	86,017
Pole Replacement Program			
Pole testing.			
Overhead Poles	TI18300	1830	6,000
Total Blanket Jobs			**98,713**
Buildings			
Replace roofing on the Operations Blding		1908	11,865
Revise the Entrance/Counter area of the Administration building to enhance security		1908	7,027
Total Buildings			**18,892**
Office Equipment			
Miscellaneous Office Equipment replacements		1915	**1,128**
Computer Equipment			
Replace fully depreciated Computer Equipment		1920	**201**
Computer Software			
M-Care, E-Care, DSM, Cayenta upgrade		1925	**7,096**
Major Tools & Instruments			
New hydraulic drill, line hose covers		1940	**4,255**

2010 Capital Plan - Newmarket					
		Units	**Job #**	**USoA**	**Total**
Grand Totals					**9,858,194**
Distribution Stations					
Bogarttown Station			CP 224		
Distribution Stations				1820	725,411
Landscape Bogarttown Station			CP 229		
Distribution Stations				1820	21,026
Total Job					746,438
Leadbeater DS complete refurbishment			CP 214		
Distribution Stations				1820	667,584
U/G Conduit				1840	8,411
U/G Conductor				1845	33,642
Total Job					709,637
Landscape and pave Twinney DS			CP 225	1820	
Distribution Stations				1820	15,770
					15,770
Total Job					**1,471,845**
Customer Additions					
Residential	Single Family	300	CP 216		
	Townhomes	150			
O/H Poles				1830	20,028
O/H Conductor				1835	20,028
U/G Conduit				1840	259,582
U/G Conductor				1845	522,215

Transformers			1850	530,013
Services			1855	663,034
Meters			1860	70,964
Contributed Capital			1950	(1,416,828)
Total Job				669,034
Commercial/Industrial	6	CP 217		
O/H Poles			1830	34,694
O/H Conductor			1835	34,694
U/G Conduit			1840	946
U/G Conductor			1845	3,785
Transformers			1850	63,079
Meters			1860	18,924
Total Job				156,121
Total Customer Additions				**825,155**
Overhead Line Additions, Rebuilds				
Holland TS		CP 212		
TS feeder egress from HONI Holland TS to Greenlane/Bathurst area. 4 feeders (approx 99 poles)..				
O/H Poles			1830	434,019
O/H Conductor			1835	434,019
Total Job				868,039
Infrastructure Project - Relocation to facilitate Viva project along Davis and along Yonge		CP 198		
O/H Poles			1830	1,096,823
O/H Conductor			1835	1,067,942
Transformers			1850	660,229
Contributed Capital			1950	(893,995)

Total Job				1,930,999
Re-insulate 41M23		CP 094		
O/H Conductor			1835	44,155
Total Job				44,155
Yonge St Pole Line Rebuild - 44kV rebuildto incorporate Holland feeders into thye Newmarket distribution system and facilitation of egress from Armitage TS for Hydro One		CP287	1830	110,720
			1835	110,720
			1950	(80,000)
Total Job				141,440
Rebuild residential overhead pole line in EG Heights - Walter Ave from Barbara to Septone due to end of life		CP 230		
O/H Poles			1830	65,708
O/H Conductor			1835	65,708
Total Job				131,415
Leslie St - Mulock to Kingdale (formerly line e/s Leslie s/o Mulock to new subd -20 spans		CP 226		
O/H Poles			1830	76,221
O/H Conductor			1835	76,221
Total Job				152,441
Doug Duncan Drive - Relocate Pole Line		CP287	1830	94,619
			1835	94,619
			1950	(60,000)
				129,238
Lundy's Lane feeder tie & open bus; from Davis Dr.. to Bolton		CP 227		
O/H Poles			1830	117,222
O/H Conductor			1835	117,222
Total Job				234,444
Gorham Street west end replace end of life pole line and upgrade #6 Cu neut. per ESA bulletins Prospect to Stewart		CP 228		

O/H Poles			1830	60,451
O/H Conductor			1835	60,451
Total Job				120,902
Total Overhead Line Additions, Rebuilds				**3,724,384**
Underground Line Additions, Rebuilds				
Eagle Hills Ph 3 - Replace end of life underground system	0	CP 231		
U/G Conduit			1840	204,335
U/G Conductor			1845	817,340
Transformers			1850	73,592
Total Job				1,095,267
UG Cane Pkwy		CP 275		
U/G Conduit			1840	41,000
U/G Conductor			1845	164,000
Contributed Capital			1950	(205,000)
Total Job				0
Total Underground Line Additions, Rebuilds				**1,095,267**
Blanket Jobs				
Replace end of life tranformers		CP 218		
U/G Conductor			1845	11,827
Transformers			1850	126,158
Faulted circuit indicators various locations	500	CP 099	1845	37,848
OH Line - Pole replacement program	15	CP 220	1830	57,823
Miscellaneous Service Upgrades/Installation		CP 222	1840	21,192
Miscellaneous Service Upgrades/Installation		CP 222	1845	67,898
				322,746
Metering				

Instrument Transformers (CT's & PT's) - Replacements	36		1860	8,640
Meter Test blocks	1		1860	3,000
Self Contained Demand (polyphase) Meter Replacements	7		1860	2,800
Smart Meter Entity charge @$8.31/meter (EDA Letter Feb 26, 2010)	32,271	NT Total $	1860	268,172
Install Smart Meters for the GS < 50kW class	0	CP 267	1860	1,540,185
Wholesale Metering			1860	16,000
				1,838,797
Leasehold Improvements				
Skylight Shade - Operations Lunch/Meeting Room			1910	3,000
Smart board			1910	6,000
Miscellaneous Leasehold Improvements- Handicap Access			1910	86,000
Total Leasehold Improvements				**95,000**
Major Tools & Instruments				
Line Department Contingency			1940	20,000
Compressor for Underground			1940	20,000
Meter Department contingency			1940	6,500
Other			1940	23,500
Total Major Tools & Instruments				**70,000**
Vehicles and Equipment				
Replace Pickup Unit # 80			1930	50,000
Replace Pickup Unit # 150			1930	35,000
Replace Van - Unit 40			1930	30,000
Total Vehicles and Equipment				**115,000**
Computer Hardware				
Replace Communications Server			1920	25,000

Replace end of life work stations			1920	15,000
Total Computer Hardware				**40,000**
Computer Software				
Survalent capital software maintenance (Scada)			1925	50,000
GIS System			1925	200,000
Total Computer Software				**250,000**
Office Equipment				
Miscellaneous			1915	10,000
Total Office Equipment			1915	**10,000**

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2010 Capital Plan - Tay

		Units	Job #	Account	Total
Grand Totals					**525,413**
Customer Additions					
Residential	Single Family	30	TP 216		
Commercial/Industrial		2	TP 217		
Underground conduit				1840	2,429
Underground conductor				1845	20,523
Services				1855	11,437
Transformers				1850	13,355
Smart meters				1860	6,346
Contributed Capital to be Amort.				1995	(38,238)
Total Customer Additions					**15,852**
Overhead Line Additions, Rebuilds					
Replace end of life pole line on 4th Avenue to Alberta in Port McNicoll.			TP013		
Overhead Poles				1830	37,949
Overhead Conductor				1835	81,077
Transformers				1850	6,189
Job Total					125,215
3 ph - Line Rebuild- Triple Bay Road, Hwy 12 in conjunction with Hydro One			TP016		
Overhead Conductor				1835	101,137
Replace end of life pole line on 7th Avenue in Port McNicoll.			TP012		
Overhead Poles				1830	29,658
Overhead Conductor				1835	11,620

Transformers			1850	4,148
Job Total				45,426
Total Overhead Line Additions, Rebuilds				**271,778**
Blanket Jobs				
Replace end of life tranformers			1850	13,124
Smart Meters			1860	141,884
Pole Replacement Program			1830	55,436
Total Blanket Jobs				**210,443**
Office Equipment				
Miscellaneous Office Equipment replacements			1915	**2,040**
Computer Equipment				
Replace fully depreciated Computer Equipment			1920	**5,100**
Computer Software				
CIS Harmonization			1925	**10,200**
Major Tools & Instruments				
Miscellaneous replacements			1940	**10,000**

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MAJOR PROJECT DETAIL

The tables presented in the next section provide additional detail for the major projects in-service in 2008, 2009 and forecast expenditures for 2010. This level of information is provided for all capital projects exceeding $86,000 and includes the background for each job, details of the work being carried out, project numbers, In-Service date etc.

NT Power Capital Project	
Investment Category:	Growth-Driven
Investment Name:	Distribution Stations
Service Area:	Newmarket
Project Name:	Boggartown Station
Project #:	CP 224
In Service:	Dec 2010

Background Information

The current station that supplies the area exceeded its capacity in 2007 during summer loading. Starting in 2006 there has been is a large residential development under construction in the area that will ultimately add about 1,000 new homes to the Applicant's distribution system. Half of these homes will be completed for connection by the end of 2010. This station is now required in order to accommodate the new load growth in the area and maintain reliability for existing customers. Legge MS has exceeded its firm capacity in the summers of 2007, 2008, 2009 and the 2010 test year.

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Project Details

The Boggartown Station project involves the construction of a complete distribution transformer station that includes the following:

- Site preparation
- Installation of a 10 MVA transformer
- 46 kV terminal pole and switches
- 15 kV switchgear
- Overhead and underground lines
- Environmental protection
- Ground grid
- Fencing
- Digital protection relays
- Supervisory connections.

Estimated Annual Expenditures

	2009	2010
Total Capital Cost		$746,438

NT Power Capital Project	
Investment Category:	Maintain Reliability
Investment Name:	Distribution Stations
Service Area:	Newmarket
Project Name:	Leadbeater Municipal Station (MS) Refurbishment
Project #	CP 214
In Service:	May 2010

Background Information

Leadbeater MS was initially placed in service in 1986. The station was built to respond to new development growth in the area. It is in the vicinity of a main roadway intersection, on the south side of Mulock Drive just east of Yonge Street. This MS transforms voltage from 44 kV to 13.8 kV. The station services 2,600 mixed residential and commercial customers in the Applicant's Newmarket service area. The Applicant's inspection and maintenance program has identified drainage problems, rusting of major equipment, including the 10 MVA station transformer and switchgear, and erosion of concrete foundations. Since its construction, subsequent development of the surrounding properties has left the station site below the surrounding elevations, and it is now subject to local flooding which has impaired the life of the asset.

Leadbeater MS was scheduled for its regular preventative maintenance in 2009. In addition, the electro-mechanical relays were scheduled to be replaced in 2009 with digital-type relays as part of the Applicant's ongoing initiative to replace the obsolete technology over time. Considering all the foregoing factors the Applicant decided to proceed with a complete refurbishment of Leadbeater MS by the end of 2009. Due to delays in procuring equipment, the project has been delayed until 2010.

Project Details

The complete station refurbishment will include an elevation change that will raise the station to the appropriate level relative to its surroundings, replacement of rusting 10 MVA transformer and switchgear, concrete equipment foundations, cables, terminations, relays, ground grid and fencing. The refurbishment will ensure that the Applicant preserves system reliability at an acceptable level.

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost		$709,637

NT Power Capital Project	
Investment Category:	Growth-Driven
Investment Name:	Customer Additions
Service Area:	Newmarket and Tay
Project Name:	Addition of Residential, Commercial and Industrial Customers
Project #:	CP 216, CP 217, TP 216 & TP 217
In Service:	Ongoing

Background Information

In order to meet the ongoing demand to connect new residential, commercial and industrial customers, the Applicant must allocate funds for new connections and upgrading existing customers. As part of its obligation to its Electricity Distribution License and the distributor's responsibility in the Distribution System Code (DSC), the Applicant is required to connect all customers on a non-discriminatory basis, upon written request for connection.

Project Details

Individual project spending within these programs is managed on a project basis. Projects include service layouts, labour, materials and other costs associated with the physical connection.

The following table shows the yearly trends for new connections based on year-end values, including the forecasted 2010 connections provided by ERA:

Year	**Number of Connections**		
	Newmarket	**Tay**	**Total**
2005	452	47	499
2006	541	48	589
2007	470	38	508
2008	655	25	680
2009 actual	668	13	681
2010	468	34	502

forecasted			
Average	**542**	**34**	**577**

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost	$1,297,893	$841,007

NT Power Capital Project	
Investment Category:	Regulatory
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Holland Junction Transmission Station (TS)
Project #:	CP 212
In Service:	Phase 1 – June 2009; Phase 2 – Sep 2010

Background Information

Since 2002, the demand for electricity in northern York Region has grown beyond the capacity of existing electricity infrastructure serving the Region. This has been recognized by the Independent Electricity System Operator (IESO) in several of its *10 Year Outlooks*. After extensive review and studies, the Ontario Energy Board (OEB) under Proceeding File No. EB-2005-0315, ordered the York Region Utilities (the former Newmarket Hydro Ltd. and Aurora Hydro Connections Limited, Power Stream Inc., and Hydro One Networks Inc.) to proceed as soon as possible with the implementation of the Holland Junction transformer station (HJTS) and the installation of distribution feeders in accordance with their joint submission of June 29, 2005, in response to the OEB's letter of June 8, 2005.

The Applicant continues to implement the above-noted OEB order by proceeding with the construction of four (4) distribution feeders from HJTS to integrate with existing Newmarket service area distribution system in two (2) phases. Phase 1 was completed in 2009 while the remaining phase, Phase 2, is planned for completion by the end of 2010 at which time a total of 70 MVA of the Applicant's load will be transferred from Armitage TS to the new HJTS. No capital contribution from the Applicant to HONI is expected to be required based on HONI's CCRA, as per the Transmission System Code (TSC), due to sufficient revenues from the Applicant's initial loading onto HJTS.

Also, as part of the implementation of the OEB order EB-2005-0315, it should be noted that the Applicant had to complete Phase 1 in order to vacate a feeder position (M11) at the Armitage TS and make it available for PowerStream in time for their summer 2009 peak demand. Completion of Phase 1 in a timely manner allowed the Applicant to transfer an initial 30 MVA of load from Armitage TS to HJTS and to free a feeder position at Armitage for PowerStream prior to the agreed-upon deadline, July 2009.

As of June 2009, the Applicant commenced transfer of load to the new HJTS, located in King Township. In doing so, the Applicant successfully secured supply to its Newmarket service area that was threatened by the overloading situation at its only supply TS at the time. The transfer also relieved the overloading situation at Armitage TS and eliminated the sole supply point situation. In addition, the project will provide more grid flexibility and increased reliability by securing redundancy of a second supply point, as well as freed a feeder position at the Armitage TS. The Applicant continues to implement the OEB order by construction of four (4) distribution feeders from HJTS to integrate into the existing Newmarket service area.

Project Details

The chart below outlines the details of the Holland Junction TS capital project. Phase 1, to be completed by the end of 2009, will see the construction of four feeders out of the new Holland Junction TS to the Newmarket service area. Phase 2 completes the Holland Junction TS feeder egress by continuing the double 44kV feeder circuits from Highway 9/right-of-way to Highway9/Yonge Street for connection with the Applicant's existing distribution system.

Phase	**Location**	**Description**
Phase 1 (2009)	Holland Junction TS to Miller Sdrd.; Greenlane to Bathurst; along HONI transmission right-of-way from Miller Sdrd. to Hwy. 9	49 poles, double 44kV circuits from Miller Sdrd. along the right-of-way to Hwy. 9 (includes one underground crossing of two feeders); 50 poles, double 44kV circuits from Millers Sdrd. to Bathurst/Greenlane and Bathurst/Hwy. 9
Phase 2 (2010)	Hwy. 9 from right-of-way to Yonge Street	24 poles, double 44kV circuits

Estimated Annual Expenditures

	2008	**2009**	**2010**
Total Capital Cost	$752,177	$1,187,951	$868,039

NT Power Capital Project	
Investment Category:	Third-Party Driven
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Bayview Pole Line Rebuild
Project #:	CP 193
In Service:	June 2009

Background Information

In accordance with the Ontario Energy Board (OEB) Order and Decision EB-2005-0315, the Applicant, in cooperation with Hydro One Networks Inc. (HONI) and PowerStream (the “York Utilties”), has implemented plans to make reconfiguration and reinforcement modifications to its primary 44 kV distribution system that have been delayed awaiting the outcome of the new transmission and transformation supply facilities. Since the overloaded Armitage TS is in the centre of the Applicant’s Newmarket service area and a single source supply, a number of 44 kV feeder reconfigurations had to be implemented in order to integrate the new supply facilities into the Newmarket distribution system.

This project was an essential component in reconfiguring and reinforcing the Applicant’s 44 kV primary supply system. It accomplished two extreme priority goals in 2009:

1. Realignment of 44 kV feeders and associated load transfers from Armitage TS to Holland Junction TS, and

2. Facilitation of egress for new feeders by other York Utilities from Armitage TS.

The project restored reliable electricity supply to the Newmarket service area of northern York Region in time for summer peak load of 2009 and will accommodate projected future load growth.

The Applicant is constructing 44 kV primary feeder lines to Holland Junction TS over a 3-year horizon to serve load growth and transfer load from the overloaded Armitage TS to the new Holland Junction TS. The net result is the most efficient supply configuration possible.

Project Details

The Bayview Avenue pole line reconstruction accommodates one 44 kV and one 13.8 kV feeder line for the Applicant and is part of the elimination of its stop-gap 44 kV primary supply changes necessitated by the long delay in construction of new supply facilities in northern York Region. It also accommodates egress from Armitage TS for 44 kV feeder lines for the other York Utilities. The incremental cost of this accommodation is appropriately treated as contributed capital to the project.

The project consists of 30 poles with 4-44kV and 1-13.8 kV feeder line south of Bayview Avenue from Armitage TS to the Newmarket/Aurora municipal boundary.

Estimated Annual Expenditures

	2009	**2010**
Total Capital Cost	$467,186	

NT Power Capital Project	
Investment Category:	Third-Party Driven
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Yonge St. Pole Line Rebuild
Project #:	CP 287
In Service:	July 2010

Background Information

In accordance with the Ontario Energy Board (OEB) Order and Decision EB-2005-0315, the Applicant, in cooperation with Hydro One Networks Inc. (HONI) and PowerStream (the "York Utilties"), has implemented plans to make reconfiguration and reinforcement modifications to its primary 44 kV distribution system that have been delayed awaiting the outcome of the new transmission and transformation supply facilities Since the overloaded Armitage TS is in the centre of the Applicant's Newmarket service area and a single source supply, a number of 44 kV feeder reconfigurations had to be implemented in order to integrate the new supply facilities into the Newmarket distribution system.

This project is an essential component in reconfiguring the Applicant's 44 kV primary supply system. It accomplished two extreme priority goals in 2009:

Realignment of 44 kV feeders and associated load transfers from Armitage TS to Holland Junction TS, and

Facilitation of egress for new feeders by other York Utilities from Armitage TS.

The project restored reliable electricity supply to the Newmarket service area of northern York Region in time for summer peak load of 2010 and allowed for future load growth.

The Applicant is constructing 44 kV primary feeder lines to Holland Junction TS over a 3-year horizon to serve load growth and transfer load from the overloaded Armitage TS to the new Holland Junction TS. The net result is the most efficient supply configuration that was planned collectively between other York Utilities.

Project Details

The Yonge Street pole line reconstruction facilitates one 44 kV feeder line for one of the other York Utilities. The incremental cost of this accommodation is appropriately treated as contributed capital to the project.

The project consists of 25 poles on Yonge St. with an additional 44kV feeder line south of Sawmill Valley South to the Newmarket/Aurora municipal boundary.

Estimated Annual Expenditures

	2009	2010
Total Capital Cost		$141,440

NT Power Capital Project	
Investment Category:	Third-Party Driven
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Doug Duncan Dr. Pole Line Rebuild
Project #:	CP 287
In Service:	June 2010

Background Information

The Town of Newmarket is redeveloping Doug Duncan Drive and adjacent facilities. In order to facilitate this redevelopment, the Town requires the Applicant to relocate their electricity distribution assets.

The Doug Duncan Dr. pole line accommodates two 44 kV and one 13.8 kV feeder line for the Applicant. The relocation costs of this pole line are being treated in accordance with section 3.4.1 of the Distribution System Code whereby the Town will pay for 50% of labour and labour saving devices totaling $60,000.

Project Details

The project consists of relocating six (6) poles with 2-44kV and 1-13.8 kV feeder line parallel to a CN right-of-way and involves one crossing of the CN right-of-way.

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost		$129,238

NT Power Capital Project	
Investment Category:	Maintain Reliability
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Tay
Project Name:	Line Rebuild – Armstrong & Davidson, Port McNicoll
Project #:	TP 007
In Service:	Nov 2009

Background Information

Through visual inspection the Applicant has determined that the poles on this section are deteriorated. The #6 copper on the primary and secondary is undersized and in poor condition. In addition, the transformers are aged and fully-depreciated. In order to meet utility standards of safety and reliability, the rebuilding this line in 2009 was a high priority.

Project Details

In 2009, the #6 copper conductors will be replaced and new transformers will be installed to rehabilitate to current safety standards. Currently, road clearances are minimal; as a result of this project, road clearances will be increased for the Applicant. The project will require extensive tree-trimming to gain access to the pole line.

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost	$182,604	

NT Power Capital Project	
Investment Category:	Maintain Reliability
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Rebuild Residential Overhead Pole Line – East Gwillimbury Heights
Project #	CP 230
In Service:	Phase 2 – May 2009; Phase 3 – Oct 2010

Background Information

In 2003, the overhead pole line serving the 400 homes in the East Gwillimbury Heights subdivision ("EG Heights") was identified as a priority for rehabilitation due to pole condition. The Applicant commenced replacement of the pole line, to maintain reliability and public safety through a phased in process.

This pole line is built to legacy construction standards consisting of 3-phase a 13.8kV primary circuit, and obsolete open wire secondary. The Applicant is rebuilding in accordance with Ontario Regulation 22/04 - *Electrical Distribution Safety* that establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems. The Applicant has put a plan in place to rebuild the pole line in 3 phases based on the deteriorating condition of sections of the line.

Phase 1 commenced in 2004 and involved replacement of the 3-phase 13.8kV primary circuit and 20 poles on Walter Av., as well as replacement of the obsolete open-wire secondary with current industry standard triplex secondary.

Phase 2, which was completed in the spring of 2009 under Job # CP 211, entailed replacement of the distribution pole line (9 poles) on Sheldon Avenue and Newbury Drive that supplies about 105 homes.

Project Details

Phase 3 is scheduled to be done in 2010 and will complete the replacement of the pole line on the remaining portion of Walter Avenue, Barbara Road. and Septonne Avenue. Once phase 3 is completed, the reliability to all customers in the EG Heights area will be preserved at levels equal to those of other customers in subdivisions served by overhead distribution. The safety standard of the pole line will be improved and upgraded to regulated standards with the elimination of the legacy construction.

Estimated Annual Expenditures

	2009	**2010**
Total Capital Cost	$65,232	$131,415

NT Power Capital Project	
Investment Category:	Growth-Driven
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Leslie Street Line Addition
Project #:	CP 226
In Service:	Dec 2010

Background Information

In 2010, the Applicant will be adding overhead lines and re-arranging circuits on Leslie Street from Mulock Drive to Kingdale Road in order to supply new load for the Copper Hills Subdivision. The work will also serve to relieve load from Legge MS by linking this area with the new Boggartown MS. Legge MS has exceeded its capacity. When temperatures reach extreme highs the risk of over loading is increased and this will further exacerbated in the future through continued customer additions in the area.

Project Details

Construction of the pole-line includes installation of a 13.8 kV circuit and 14 poles to service the Copper Hills residential subdivision development of 200 new homes.

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost		$152,441

NT Power Capital Project	
Investment Category:	Maintain Reliability
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Lundy’s Lane Feeder Tie & Open Bus
Project #	CP227
In Service:	Sep 2010

Background Information

The Applicant is replacing a deteriorating pole line on Lundy’s Lane from Davis Dr. to Bolton Avenue. The deterioration was identified during routine inspection in 2003 and the pole line was recommended as a priority for rehabilitation due to pole condition and conductor capacity. The project was postponed due to a higher priority feeder relocation on Davis Drive to accommodate facility expansion of Southlake Regional Health Centre (Southlake relocation). The Southlake relocation required configuration of the Lundy’s Lane pole line where it intersects Davis Drive. As such, the final design for Lundy’s Lane was postponed to avoid unnecessary duplication of engineering design and construction costs. This portion of the Applicant’s distribution grid serves as an important inter-station feeder tie. In order to maintain flexibility to transfer load between their Andrews MS and Gilbert MS, the size of the primary needs to be upgraded to carry up to 400 Amps. Currently it is limited to half that ampacity.

When completed, this Lundy’s Lane project will reinforce a key feeder inter-station tie and allow faster (single step) restoration of power in a contingency situation. It will also eliminate legacy construction on this portion of the distribution grid and bring it up to current regulated safety standards.

Further delay of this pole line upgrade increases the risk to reliability of the Applicant’s distribution system by reducing their flexibility to readily restore power in a contingency situation. Reliable supply to about 700 customers is at risk.

Project Details

The Applicant will upgrade the deteriorating pole line from legacy construction to current safety standards. This involves upgrading the 13.8 kV primary circuits to double its ampacity,

replacing obsolete open bus secondary, upgrading to suitable neutral, and replacement of deteriorating wood poles.

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost		$234,444

NT Power Capital Project	
Investment Category:	Maintain Reliability
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Gorham Street – Replace Pole Line
Project #:	CP 228
In Service:	Dec 2010

Background Information

The Applicant is replacing a deteriorating pole line at the west end of Gorham Street from Prospect Street to Stewart Avenue. This pole line was constructed using a #6 copper neutral. Inspection of the line has also identified deteriorated poles. The Electrical Safety Authority (ESA) identified the presence of #6 copper neutral as a safety concern and encourages electricity LDC's to upgrade this neutral to a suitable size; same conductor as phases. Legacy under-sized neutrals are insufficient for today's requirements and there is a risk of it burning and falling down. Due to the presence of the #6 copper neutral and the conditions of the poles, the Applicant has made this a priority project.

Project Details

The Applicant will upgrade the deteriorating pole line from legacy construction to current safety standards. This involves transferring the 13.8 kV primary circuits, replacing open bus secondary, and replacing the #6 copper wire with suitable sized neutral, and replacement of deteriorating wood poles. In addition, 45 services will need to be transferred unto the new pole line. Improved public safety and reliability are outcomes of this project.

Estimated Annual Expenditures

	2009	2010
Total Capital Cost		$120,902

NT Power Capital Project	
Investment Category:	Maintain Reliability
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Tay
Project Name:	Replace Pole Line – 4th Avenue to Alberta, Port McNicoll
Project #:	TP 013
In Service:	Sep 2010

Background Information

Through visual inspection, the Applicant has detected deteriorated and undersized poles in the pole line from 4th Avenue to Alberta in Port McNicoll. The line will be changed from 35' poles to 45' poles in order to increase clearances and improve reliability for the main three-phase feed in Port McNicoll.

Project Details

In 2010, the Applicant plans to replace the end of life poles in order to ensure safety and reliability for the 275 customers fed by this pole line. This is a three-phase line with three joint-use partners. The line presently consists of 35' wooden poles with wooden cross arms that require replacement due to their condition.

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost		$125,215

NT Power Capital Project	
Investment Category:	Third-Party Driven
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Tay
Project Name:	Line Addition/Rebuild – Triple Bay Road, Hwy 12
Project #:	TP 016
In Service:	Dec 2010

Background Information

Hydro One Networks Inc. (HONI) is building a pole line to reduce the load in Midland and change the feed to Port McNicoll MS. In conjunction with HONI, the Applicant will be assisting in the line addition on Triple Bay Road; the road is a rural joint-use area between the Applicant and HONI.

Project Details

The existing three-phase line, built under the HONI line, requires relocation and will be transferred to the new poles. Complete details of the timing on this project are not known at this time, but construction is expected to be completed in 2010.

Estimated Annual Expenditures

	2009	2010
Total Capital Cost		$101,137

NT Power Capital Project	
Investment Category:	Maintaining Reliability
Investment Name:	Underground Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Eagle Hills – Replace Underground System
Project #:	CP 199 & CP 231
In Service:	Phase 2 – Nov 2009; Phase 3 - Sep 2010

Background Information

The underground cable systems in the area of Eagle Hills subdivision are over 30 years old and have increasingly been subject to cable faults.

The cables are unjacketed direct-buried and therefore cannot be rehabilitated. The cables' concentric neutrals have started to deteriorate. The Applicant considers replacement of an underground distribution system a requirement when three or more cable faults have occurred on it within one year. Cable faults started to appear in this subdivision in 2000 and one section was replaced at that time. There have been additional faults since then and more recently, occurrences have increased in frequency. There were three documented faults in the first half of 2008. Replacement of the underground distribution system in the Eagle Hills subdivision area commenced in the fall of 2008 with Phase 1. This first phase entailed replacement of cables and transformers supplying 43 homes and was completed by December 31, 2008.

Project Details

The Applicant completed Phase 2 of 3 in 2009; Phase 2 involved replacement of the underground distribution system servicing 84 homes in the Lorne Avenue, Denne, Ella Court, and Glenrose Avenue areas. Phase 3 consists of replacement of the underground distribution system servicing 110 homes in the Roywood Crescent, Astor Drive, and Cloverdale Court areas and will be completed in 2010.

Upon completion of Phase 3, electricity service reliability will be restored to levels equivalent to other underground subdivisions in the Newmarket service area.

Estimated Annual Expenditures

	2009	2010
Total Capital Cost	$903,047	$1,095,267

NT Power Capital Project	
Investment Category:	Third-Party Driven
Investment Name:	Overhead Line Additions, Rebuilds
Service Area:	Newmarket
Project Name:	Infrastructure Project – Davis Drive and Yonge Street
Project #:	CP 198
In Service:	Per Viva Schedule

Background Information

In conjunction with its Places to Grow and MoveOntario initiatives, the Government of Ontario through its transportation agency (MetroLinx) has identified Newmarket as a Mobility Hub in the province's Regional Transportation Plan. The plan includes an extension of the Yonge Street subway to the Gateway Hub in Richmond Hill just north of Highway 7 and the construction of a dedicated median bus lane (Rapidway) continuing north on Yonge Street to join the intermodal transportation system to Newmarket. As an urban growth centre and designated interchange hub, Newmarket is a key component of the provincial plan objectives to improve public transportation efficiency, lower greenhouse gas emissions and facilitate density intensification along the transportation corridor.

The Regional Municipality of York (the Region) has been working with the province and a consortium of seven private sector partners (York Consortium 2002) to manage the planning and development of the median Rapidway along Yonge Street and Davis Drive in Newmarket. Both of these transportation corridors are regional roads and the proposed rapid transit system will be owned and operated by the York Region Rapid Transit Corporation as VivaNEXT.

The Region has started Preliminary Engineering work on the Rapidways on Yonge Street and Davis Drive and has developed a road allowance cross-section to accommodate a like-for-like relocation of overhead distribution lines.

The project will have a major impact the roadways on Davis Drive from Yonge Street to the Southlake Regional Health Centre at Roxborough Road.; on Yonge Street from the Aurora/Newmarket municipal boundary to Green Lane; and on Green Lane from Yonge Street to Leslie Street. The initial phase on Davis Drive from Yonge Street to Roxborough Road entails widening the existing road to six (6) lanes starting in 2010.

The VivaNEXT project timelines are very aggressive and have been difficult to work with definitively as most of the engineering design work is not final. Based on the preliminary plans received in the latter part of the spring in 2009, the Applicant must relocate 366 poles of its distribution plant along Davis Drive and Yonge Street in order to facilitate the initial implementation of the project. Detailed plans for the Green Lane phase have not been provided to the Applicant. The Region is also considering, as part of its Draft Official Plan (the Draft Plan), "to require underground installation of utilities in new community areas and in Regional Centers and Corridors, and to encourage buried utilities in the balance of the Region" (York Region Official Plan, Draft June, 2009, Page 95).

The Applicant anticipates the relocation of its existing distribution plant to be completed in four phases. The first phase requires the Applicant to facilitate the bridge construction on Davis Drive scheduled to commence in 2010. The second phase will be to complete relocation of some 140 poles and attached circuits on Davis Drive between Yonge Street and Roxborough Road by the end of 2010. The Applicant anticipates that it will be required to complete phase 3, relocation of its plant on Yonge Street between the Aurora/Newmarket municipal boundary and Davis Drive in 2015. The relocation of distribution plant on this section of Yonge Street involves moving over 115 poles. Phase 4 would require the Applicant to move the remainder of the pole lines along Yonge Street and on Green Lane.

Should the Region decide to implement the underground facilities vision in its Draft Plan, the relocation costs to bury the Applicant's electricity distribution are expected to be 10 to 15 times the cost of overhead relocation. This is partially due to the fact that 44kV rated underground equipment is not readily or commonly available. As such, the Applicant has initiated discussions with the Region, VivaNext and the Town of Newmarket to develop a financing plan (the U/G Plan) for this possibility. The U/G Plan is based on all funding for construction of required underground electric distribution facilities to serve existing load being financed 100% by the Region and funding for required reinforcements to serve load growth envisioned in the Places to Grow and MoveOntario initiatives to be in accordance with the Distribution System Code.

Funding for relocation on this scale and under constrained timeframes is of great concern to the Applicant. In their letter of July 23, 2009, VivaNEXT indicated that their cost contribution for the relocation will be in accordance with the Public Service Works on Highways Act i.e. only 50% of labour costs for relocations. For the purposes of the rebasing filing, the Applicant has assumed all relocation costs over and above those required for a ‘like-for-like’ relocation will be in the form of a capital contribution. This assumption may need to be changed depending on the outcome of the U/G Plan negotiations. Further meetings have been scheduled with representatives from VivaNEXT, the Town of Newmarket and the Region.

In addition to the possibility of a rate base adjustment for the test year, the Applicant is also seeking approval from the Board to readjust its rate base in the subsequent years as additional phases of the project and the associated distribution relocation work is scheduled and completed. The Rapidway construction has been planned as a multi-year project requiring significant non-discretionary capital expenditures from the impacted distribution utility. Further, the timing of the phases of the project has been and continues to be subject to availability of provincial infrastructure grants. The Yonge Street phase is currently on a 4 year deferral. The Applicant notes that this is still a MetroLinx priority and should additional infrastructure dollars come available, the deferral will be lifted moving the 2014 completion date to 2011 or 2012. In this event, the Applicant would be required to file a rebasing application when the capital adjustment module threshold was not triggered. To avoid the regulatory costs associated with annual rebasing applications, the Applicant is requesting that the Board approve the need and justification for the project in the current proceeding along with the costs expected to be incurred in the test year and a preliminary estimate of the costs of the future phases. The Applicant is also seeking approval from the Board to review the future costs spent each year in a limited issues rates hearing where the actual costs for the current year could be reviewed and the Board would determine the appropriate rate base adjustment for that phase. This approach has been used in other jurisdictions and is in keeping with the Board’s innovative approach to capital expenditures related to the provincial initiatives for renewable energy.

Project Details

Phase 1 is to be completed in 2010 in order to facilitate bridge construction on Davis Drive. This involved 5 poles and relocation of 44kV and 13.8kV primary circuits and the re-routing of secondary service to commercial customers within the vicinity of the bridge.

Phase 2 involves extensive relocation of the Applicant's pole lines on Davis Drive between Yonge Street and Roxborough Road. The Applicant's existing overhead electricity distribution infrastructure along Davis Drive and Yonge Street consists of 140 poles that support 44kV, 13.8kV, low voltage "LV" circuits, street-lighting circuits and fixtures, customer-owned LV circuits, services to customers, transformers, switches and fuses, and joint-use telecommunication circuits. There are eight (8) customers along the impacted section of Davis Drive with customer owned 44kV-660/347V stations that will need to be re-supplied. The Southlake Hospital is a key customer that requires high level of reliability to be maintained during the relocation. Construction alone is expected to take 6 to 8 months to complete.

Estimated Annual Expenditures

	2009	2010
Total Capital Cost	$0	$1,937,576

NT Power Capital Project	
Investment Category:	Maintain Reliability
Investment Name:	Blanket Jobs
Service Area:	Newmarket and Tay
Project Name:	Replace End of Life Transformers
Project #:	CP 218 & TP 218
In Service:	Ongoing

Background Information

There are 1119 pole mounted transformers and 2851 pad mounted transformers in the Applicant's combined service areas. In the Newmarket service area, 83% are pad mount transformers, while in the Tay service area, the majority, or 92%, are pole mount.

Type of Transformer in Newmarket and Tay Service Areas			
Service Area	**Pad Mounted Transformers**	**Pole Mounted Transformers**	**Total**
Newmarket	2802	587	3389
Tay	49	532	581

In order to preserve reliability and fulfill environmental responsibility, the requirement for transformer replacement is identified through routine inspections, reports from field crew and from customers in the Newmarket and Tay service areas. The transformers that are replaced under this program are usually a single transformer on street as opposed to several transformers located in the same area. Where most of the transformers requiring maintenance are located on one street with five or more transformers, a separate project is identified and executed under a specific capital budget item.

Project Details

Replace 15 transformers per year (the Applicant anticipates mostly single-phase pad mounted transformers) at various locations that are identified as requiring maintenance. Examples of transformers requiring replacement are: leaking oil, hit and run, rusting, deteriorating foundations, damaged grounding, cutouts and lightning arresters. The London Road area of the

Newmarket Service Territory has been identified as a priority area in 2010 due to the aging of these assets.

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost	$137,794	$139,282

NT Power Capital Project	
Investment Category:	Maintain Reliability
Investment Name:	Blanket Jobs
Service Area:	Newmarket and Tay
Project Name:	Pole Replacement Program
Project #:	CP 220 & TP 220
In Service:	Ongoing

Background Information

NTP owns and monitors over 5,300 poles in it's service areas These poles support over 600 km of the Applicant's overhead distribution power lines, other LDCs distribution circuits, municipal street lighting and telecommunications infrastructure under joint-use agreements.

In order to preserve reliability in the Newmarket and Tay service areas, as well as that of other joint-use assets as per joint-use agreements, the Applicant ensures the integrity and safety of these important assets by inspection and maintenance. The requirement for pole replacement is identified from routine inspections, reports from field crews going about their daily work, and from customers in the Newmarket and Tay service areas.

The poles and associated guying/anchoring that are replaced under the Pole Replacement Program are usually a single pole as opposed to several poles located in the same area. Where more than five poles requiring replacement are located on one street or within a single area, a separate project is identified and executed under its own capital budget item.

Project Details

Based on historical averages, the Applicant projects the replacement of 25 to 30 poles at various locations that are identified as requiring maintenance (e. g. rotten, burnt or broken poles, missing or damaged guying, anchoring and/or guy guards, rotten cross arms) in the Newmarket and Tay service areas.

Estimated Annual Expenditures		
	2009	**2010**
Total Capital Cost	$67,955	$113,259

NT Power Capital Project	
Investment Category:	Regulatory
Investment Name:	Blanket Jobs and Metering
Service Area:	Newmarket and Tay
Project Name:	Smart Meter Deployment and Application of Time-of-Use (TOU) Pricing
Project #:	CP 276 & TP 276
In Service:	Ongoing

Background Information

The Applicant has been named in provincial legislation as a priority installation utility under Ontario Regulation 428/06 and is permitted to carry out the functions of the Smart Meter Entity, under O. Reg. 233/08, for all its customers with a smart meter.

The Applicant began its smart meter deployment for all residential customers in the Spring of 2007. By the end of 2008, all eligible residential customers in Newmarket had a smart meter installed. The Applicant began integration and testing with the provincial MDMR in April of 2007. Meter registration, and data transmission were completed by May. Billing data acquisition from the provincial MDM/R for 250 RPP-eligible customers began in April 2008 to allow the Applicant to comprehensively test MDMR integration. Using a contracted MDMR service, the Applicant has migrated all eligible residential customers in Newmarket to TOU pricing on a billing cycle by billing cycle basis. The Applicant successfully implemented changes in business processes and CIS to implement TOU billing. TOU data is available on the Applicant's website for all customers with a smart meter. As consumers are migrated to TOU pricing, they receive an education package consisting of an introductory letter, two months of consumption history in TOU format, and the Smart Meter information brochure produced by the Ministry of Energy and Infrastructure.

Project Details

The Applicant plans to have all residential customers on TOU pricing and migrate the billing data acquisition from the contracted MDM/R service to the provincial MDM/R by the end of

2010. The contracted MDM/R service has been equipped with specific quality management attributes to support priority installation that allow the Applicant and its SMI vendor to identify quality control issues during meter deployment and initial framing of TOU billing quantities. For this reason, the contract MDM/R is used for TOU pricing and then compared to the provincial MDM/R. Once installation and migration to TOU pricing is completed as per the government regulation, the provincial MDM/R will be used exclusively for billing data management. acquisition.

During 2010, smart meters will be deployed to all GS<50 customers. As of June 30, 2009, smart meters have been installed for 677 of the 3,500 eligible GS<50 customers. The Applicant intends to be executing billing data acquisition for all GS<50 customers by the end of 2010. Following the completion of smart meter installation for the GS<50 customers, the Applicant plans to migrate them to TOU pricing by the end of 2010.

Estimated Annual Expenditures

	2008	2009	2010
Total Capital Cost	$849,116	$473,285	$2,027,551

NT Power Capital Project	
Investment Category:	Internally-Driven
Investment Name:	Fleet
Service Area:	Newmarket
Project Name:	Single Bucket Truck and Dump Truck Replacement
In Service:	Bucket – Nov 2009; Dump – Aug 2009; 2 pickups & 1 van - 2010

Background Information

The Applicant's fleet is an integral tool for providing safe and reliable service for the rapid response to various contingency situations occurring in its distribution service areas. In order to respond to trouble calls efficiently, and avoid downtime and delays in maintenance and construction, the Applicant ensures it has a safe, reliable and well-maintained fleet. The Applicant's linepersons are required to do bare-hand live-line work on 44,000 V power lines; therefore, it is imperative that their fleet is tested, maintained and updated regularly.

In accordance with the Applicant's long-term fleet replacement program, two units were replaced during 2009. The plan takes into account mileage, age, maintenance costs, body condition, and usage (including PTO hours for larger vehicles). It also takes into consideration the "lumpiness" of costs for fleet replacement and attempts to smooth fleet expenditures over their ten-year fleet plan. Small trucks are considered for replacement after five years, whereas large trucks (including the chassis and dielectric booms), the threshold is eight to ten years.

Project Details

In 2009, two vehicles were replaced - a dump truck (Unit 120) and a 1996 single bucket truck (Unit 310).

The 2002 dump truck, unit 120, is a small truck that transports the screening for poles and concrete foundations, fill, sod and salt for all projects. It had considerable rust, is approaching 100,000 km in mileage, and has lasted two years beyond its originally scheduled replacement date. This truck is a necessity for the completion of construction and maintenance work.

Unit 310 is a 40 foot single bucket truck used for capital construction, maintenance and larger trouble calls. Its usage is approaching 5,000 PTO hours and mileage has reached 70,000 km. The Applicant has kept the truck three years beyond its scheduled replacement date. Delaying replacement risks the occurrence of breakdowns and increased downtime for repairs thereby increasing the possibility of longer power outages. Without replacement, maintenance frequency and costs could increase significantly and safety could be jeopardized.

In 2010, three small vehicles are scheduled to be replaced – two pickups and a van. Each of these vehicles will reach the five year threshold mentioned above and are fully depreciated.

Estimated Annual Expenditures

	2009	**2010**
Total Capital Cost	$346,763	$115,000

NT Power Capital Project	
Investment Category:	Internally-Driven
Investment Name:	Computer Software
Service Area:	Newmarket
Project Name:	GIS System

Background Information

The Applicant requires a GIS system to contain and centralize its entire asset data and to enable asset management processes. The Applicant will use GIS to help support and control processes such as inspection, maintenance, capital planning, inventory tracking and application of Electric Safety Authority requirements and safety bulletins and financial management that affect the assets. A GIS will also integrate these processes by providing a common base of asset data and an efficient means for the exchange of information across functional departments and with 3rd party entities e.g. “one-call” companies for cable locate services.

The Applicant needs inspection, maintenance and asset records to be readily available to operating, engineering, and field personnel and GIS will facilitate ready access to inspection records for any given asset, seeing spatial relationships with respect to outages, past inspection activities, asset age and cost and condition.

GIS will enable field personnel to restore power more quickly by having remote access to utility information systems close to real time. Also, time-consuming, error- prone manual data transcribing inputs will be replaced by quicker electronic means.

Outage and usage data collected by the Applicant’s SCADA system can be integrated with GIS to facilitate analysis of the Applicant’s distribution grid performance, as well as assist in project planning.

The Applicant notes that GIS is identified as one of the key prerequisite for implementation of smart grid strategies..

Key practices listed in an OEB commissioned report by KPMG: *Review of Asset Management*

Practices in the Ontario Electricity Distribution Sector March 10th, 2009, identifies GIS as follows:

- Inspection records should be available electronically and, ideally, integrated with the utility's Geographic Information System ("GIS"). This allows control room and other personnel to readily bring up the inspection records for any given asset, and to see spatial relationships with respect to outages, past inspection activities, and asset age and condition.

- GIS systems will facilitate spatial analysis of outage data and maintenance histories. This should allow utilities to improve the effectiveness of their inspection and maintenance processes _ Automated work order systems and project tracking software will allow better monitoring of actual capital costs. This will improve feedback in the capital delivery process.

- The state of a utility's GIS is thus an indicator of the ability of a utility's information systems to support good asset management practices. Several utilities that we visited were in the process of implementing new GIS systems, and this was a significant focus of their IT effort in the operations area.

Project Details

- Develop and issue an RFP for GIS, including conversion. The estimated value is 5% lower than a more detailed budget estimate provided by a potential vendor.
- Evaluate and Award contract for GIS
- Implementation including Conversion & Testing
- Develop and document processes to maintain data and integrity of data
- Training

Estimated Annual Expenditures

	2009	2010
Total Capital Cost		$200,000

INVESTMENT PLANNING PROCESS & STRATEGY

Capital Budgeting Process and Asset Management

The projects that The Applicant selects for its capital budget are the ones that are required to ensure the safety, efficiency, and reliability of its distribution system. The projects are supported by a combination of asset inspection, individual asset performance, and asset age, in addition to considering the technical feasibility of employing life-extending techniques, reliability, and reliability statistics.

Where there are significant reliability or safety concerns, these projects are given top priority. In determining reliability priorities, The Applicant considers the following characteristics of its distribution system:

- Failure of one 44 kV feeder line interrupts approximately 20% of total system load
- Failure of a substation interrupts approximately 10% of total system load
- Failure of a 13.8 kV feeder line interrupts approximately 5% of total system load
- Overhead lines take hours to repair while underground cables take days

As a result, 44 kV assets receive highest priority followed by substations and 13.8 kV facilities. Underground cables are replaced in a systematic manner over time, once end of life indicators are present.

On a micro level, when individual assets have reached their normal end of life and the cost of maintenance and/or the frequency of service disruptions has reached an unacceptable level, the individual asset is identified for maintenance or replacement. If the malfunction of these identified assets would create a significant reliability, safety, or service problem, the asset is scheduled to be replaced within the current year's budget. When assets are identified for replacement, the assets in the poorest condition are replaced first. In the instance where assets are closing in on the end of their useful life but are currently still functioning although not optimally and the need for replacement in the near future is high, the project is considered for replacement in the current budget if there is room for minor discretionary spending (or alternatively in the upcoming budgets on the same basis). Assets that have not reached their normal life expectancy and are functioning productively are left in service and maintained as required based on service reliability, fault monitoring and regular inspections as required under the Distribution System Code.

The Applicant's asset management process ensures that no lines are replaced before the need arises. For underground replacement, the Applicant continues to repair faults as they occur until the frequency in any one year reaches three faults at which time the asset is considered for replacement. Underground lines generally have an operating life of 25 years. For overhead lines, The Applicant reviews the performance and inspects the asset condition of all older lines annually. Overhead lines generally have a life expectancy of 25 to 30 years and the replacement is usually driven by the condition of the poles and the combined load that they service.

ASSET MANAGEMENT

The Applicant maintains the efficiency and reliability of its distribution system through an active inspection, maintenance and asset management program that focuses on customer service, employee safety and cost-effective maintenance, refurbishment and replacement of assets that can no longer meet acceptable utility standards. The company considers a wide range of factors when deciding whether to maintain, refurbish or replace a distribution asset, including public and employee safety, service quality, rate impacts, maintenance costs, fault frequency, asset condition, and life expectancy.

When an asset has reached its normal life expectancy and the cost of maintenance and/or the frequency of service disruptions have reached an unacceptable or uneconomic level, the asset is identified for refurbishment or replacement. If the malfunction of these identified assets would create a significant safety, reliability or service impact, the assets are replaced within the current year's budget. Assets that have not reached their normal life expectancy are left in service and refurbished as required based on service reliability, fault monitoring and regular inspections as required under the Distribution System Code.

The Applicant's asset management process ensures that no lines are replaced before the need arises. For underground replacement, The Applicant continues to repair faults as they occur until the frequency in any one year reaches three faults at which time the asset is replaced. Underground lines generally have an operating life of 25 years. For overhead lines, The Applicant reviews the performance and inspects the asset condition of all older lines annually. When distribution plant is identified for replacement, the assets in the poorest condition are replaced first. Overhead lines generally have a life expectancy of 25 to 35 years and the replacement is usually driven by the condition of the poles and the combined load that they service.

Asset replacement is considered annually as part of The Applicant's budgeting process along with the other capital projects scheduled for completion in the upcoming year.

Where there are safety or reliability concerns the replacements are given top priority and are included in the current year's spending. Where the asset condition is acceptable but the probability of the need for replacement in the near term is high, the project is considered for replacement in the current budget if there is room for discretionary spending or in the upcoming budgets on the same basis. Discretionary replacements cannot be deferred indefinitely but in the short-term they provide a degree of planning flexibility to help keep annual capital expenditures stable. When replacement is determined to be more economic than refurbishment and/or ongoing maintenance, it is cost effective to install a new asset.

Exhibit 2: Rate Base

Tab 5 (of 6): Allowance for Working Capital

DERIVATION OF WORKING CAPITAL ALLOWANCE

The Working Capital Allowance ("WCA") is designed to provide an adequate ongoing cash flow to distributors in advance of recovery through rate collection. Its most meaningful component is the cost of power, and cost items associated with the cost of power, which represent the distributor's primary business liability.

The methodology used by The Applicant in calculating the WCA is consistent with the 2006 Electricity Distribution Rate Handbook. HHI's WCA is presently calculated as 15% of the sum of the cost of power and the controllable distribution expenses. These accounts include the groups and accounts listed below.

The Applicant's projected WCA for 2010 is $9,730,814 Details of the derivation of this amount can be found at Exhibit 2, Tab 5, Schedule 1, Attachment 1.

Distribution Expenses – Operation

5005 Operation Supervision and Engineering
5010 Load Dispatching
5012 Station Buildings and Fixtures Expense
5014 Transformer Station Equipment - Operation Labour
5015 Transformer Station Equipment - Operation Supplies and Expenses
5016 Distribution Station Equipment - Operation Labour
5017 Distribution Station Equipment - Operation Supplies and Expenses
5020 Overhead Distribution Lines and Feeders - Operation Labour
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses
5030 Overhead Sub-transmission Feeders - Operation
5035 Overhead Distribution Transformers- Operation
5040 Underground Distribution Lines and Feeders - Operation Labour
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses
5050 Underground Sub-transmission Feeders - Operation
5055 Underground Distribution Transformers - Operation
5060 Street Lighting and Signal System Expense
5065 Meter Expense
5070 Customer Premises - Operation Labour
5075 Customer Premises - Materials and Expenses

5085 Miscellaneous Distribution Expense
5090 Underground Distribution Lines and Feeders - Rental Paid
5095 Overhead Distribution Lines and Feeders - Rental Paid
5096 Other Rent

Distribution Expenses – Maintenance
5105 Maintenance Supervision and Engineering
5110 Maintenance of Buildings and Fixtures - Distribution Stations
5112 Maintenance of Transformer Station Equipment
5114 Maintenance of Distribution Station Equipment
5120 Maintenance of Poles, Towers and Fixtures
5125 Maintenance of Overhead Conductors and Devices
5130 Maintenance of Overhead Services
5135 Overhead Distribution Lines and Feeders - Right of Way
5145 Maintenance of Underground Conduit
5150 Maintenance of Underground Conductors and Devices
5155 Maintenance of Underground Services
5160 Maintenance of Line Transformers
5165 Maintenance of Street Lighting and Signal Systems
5170 Sentinel Lights - Labour
5172 Sentinel Lights - Materials and Expenses
5175 Maintenance of Meters
5178 Customer Installations Expenses- Leased Property
5195 Maintenance of Other Installations on Customer Premises

Working Capital Allowance by Expense Account

Working Capital Allowance by Expense Category

	US of A	2006	2007	2008 Actual	2009 Actual	2010 Test
Cost of Power						
Power Purchased	4705	42,645,650	43,047,462	42,780,154	43,453,995	44,394,543
Charges - WMS	4708	3,823,944	3,798,160	4,344,774	4,335,340	4,643,033
One Time	4712	32,335	142,697	(13,476)	19,547	0
Charges - NW	4714	4,299,419	4,207,506	3,716,799	3,552,823	4,525,660
Charges - CN	4716	3,558,373	3,553,518	3,207,201	3,175,485	3,368,696
Total COP		**54,359,722**	**54,749,344**	**54,035,453**	**54,537,190**	**56,931,933**
OM&A						
Operation & Maintenance		1,860,955	1,894,991	1,831,140	2,208,026	2,560,224
Billing & Collecting		1,501,889	1,653,517	1,750,464	1,852,686	2,331,264
Community Relations & Advertising		107,754	79,476	72,007	63,202	76,332
Administration Labour & Exp		2,068,003	2,263,092	2,374,534	2,442,373	2,798,398
Total OM&A		**5,538,601**	**5,891,076**	**6,028,145**	**6,566,288**	**7,766,218**
Property & Capital Tax						
Property & Cap Tax		**267,531**	**271,857**	**260,277**	**246,309**	**173,946**
Total for Working Funds Allowance Calc		**60,165,854**	**60,912,277**	**60,323,875**	**61,349,787**	**64,872,097**
Working Funds Allowance	**15%**		**9,136,841**	**9,098,540**	**9,202,468**	**9,730,814**

Exhibit 2: Rate Base

Tab 6 (of 6): Service Quality and Reliability Performance

SERVICE QUALITY AND RELIABILITY PERFORMANCE

The Applicant continues to expand and build up its distribution system in order to meet the demand of new and existing customers in its service territory. This increase in demand comes both from expansion of the distribution system into currently non serviced areas and distribution system upgrades needed in existing areas.

Service quality has always been a priority for the company. The Applicant has consistently exceeded the OEB's Service Quality Indicators, as set out in this schedule.

The Applicant monitors and reports service quality indicators as required in Chapter 15 of the Ontario Energy Board 2006 Electricity Distribution Rate Handbook. A list of the service quality metrics that a distributor is required to measure and report back to the OEB is provided below.

Customer Service	**Customer Service**
• Connection of new services • Underground cable locates • Appointments • Telephone accessibility • Written response to enquiries • Emergency response	• System average interruption duration index • System average interruption frequency index • Customer average interruption duration index

Definitions of the above quality metrics can be found in Chapter 15 of the Ontario Energy Board 2006 Electricity Distribution Rate Handbook.

The Applicant strives to establish its operating performance at levels no less than the minimum standards, taking into consideration the needs and expectations of its customers. The Applicant Customer Service and Service Reliability results and targets from 2007 to 2009 are shown at the following pages.

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Report Summary

Filing Year	Filing Form Name	Filing Form Description
2008	2.1.4	Service Quality Indicator
RRR Filing No	**Reporting Period**	**Extension Granted**
2,611	January- 2008Newmarket Hydro Ltd., Newmarket: ; ED-2002-0553; ;	
Report Version	**Due**	**Extension Deadline**
0	January 31, 2008	
Status	**Submitter Name**	**Submitted On**
Submitted	David Weir	January 31, 2008
Licence Type		**Expiry Date**
Distributor		May 1, 2010

New Connection - Low Voltage (LV)

The percentage of new low voltage (<750 Volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code.

OEB Approved Standard: 90% or more

Month	# of new LV Services connected within 5 Days	# of new LV Services connected	% of # of new LV Services connected within 5 days
January	23	23	100.00
February	20	20	100.00
March	13	14	92.86
April	27	27	100.00
May	28	34	82.35
June	49	49	100.00
July	25	25	100.00
August	56	56	100.00
September	67	67	100.00
October	107	107	100.00
November	72	72	100.00
December	40	44	90.91

New Connection - LV Annual Total

Total # of new LV Services connected within 5 Days	Total # of new LV Services connected	NC LV AnnualTotal Percentage
527	538	98.00

New Connection - High Voltage(HV)

The percentage of new high voltage (>=750 Volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of new HV Services connected	# of new HV Services	% of new HV Services connected

	within 10 Days	connected	within 10 Days
January	0	0	0.00
February	0	0	0.00
March	2	2	100.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

New Connection - HV Annual Total

Total # of new HV Services connected within 10 Days	Total # of new HV Services connected	NC HV Annual Total Percentage
2	2	100.00

Appointments Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code

Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of Appointments scheduled as required	# of Appointment requests received in the month	Percentage Appointments Scheduled as Required
		No Records	

Appointment Scheduled - Annual Total

Total # of Scheduled	Total # of Requested	Appointments Scheduled Total Percentage

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment is scheduled as required and the appointment date and time is met.

Please refer to section 7.4 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of visits to customer's site where Appointment scheduled and completed as required	# of Appointments with customer/representative	% Appointment Met
January	12	12	100.00
February	12	12	100.00
March	9	9	100.00
April	4	4	100.00
May	10	10	100.00
June	21	21	100.00

July	24	24	100.00
August	16	16	100.00
September	22	22	100.00
October	10	13	76.92
November	18	20	90.00
December	15	15	100.00

Appointments Met - Annual Total

Total # of Appointments Met	Total # of Appointments requiring meeting with customer	Appointments Met Annual Total Percentage
173	178	97.20

Rescheduling a Missed Appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed

Please refer to section 7.5 of the Distribution System Code

OEB Approved Standard: 100%

Month	# of Appointments Rescheduled as Required	# of Missed/About to be Missed Appointments	% Appointments Rescheduled
No Records			

Appointments Rescheduled - Annual Total

Total # of Appointments Rescheduled	Total # of Appointments Missed/About to be Missed	Appointments Rescheduled Annual Total Percentage

Telephone Accessibility (TelefonServicFactor TSF)

The percentage of calls to the utility's general inquiry number that are answered in person within 30 seconds.

Please refer to section 7.6 of the Distribution System Code

OEB Approved Standard: 65% or more

Month	# of General Inquiry Telephone Calls Answered within 30 Sec	# of General inquiry Calls	% TSF
January	1,741	1,833	94.98
February	1,908	2,082	91.64
March	2,460	2,651	92.80
April	2,803	3,012	93.06
May	2,976	3,097	96.09
June	1,777	1,955	90.90
July	2,943	3,267	90.08
August	1,264	1,353	93.42
September	2,209	2,531	87.28
October	2,805	3,236	86.68
November	2,500	2,947	84.83
December	1,426	1,568	90.94

Telephone Accessibility Annual Total

Total # General Inqury Telephone Calls

Total # General Inqury Telephone Calls

Answered within 30 Sec	Total # of General Inquiry Telephone Calls	Percentage
26,812	29,532	90.80

Telephone Call Abandon Rate

The percentage of telephone calls that are abandoned before they are answered

Please refer to section 7.7 of the Distribution System Code

OEB Approved Standard: 10% or less

Month	# of Telephone Calls Unanswered or Abandoned after 30 seconds	Total # of Telephone Calls Received	% Telephone Calls Abandoned
No Records			

Total # of Calls Missed	Total # of Telephone Calls Received	Telephone Calls Abandoned - Annual Total Percentage

Written Responses to Enquiries

The percentage of customer enquiries requiring a written response where the response is provided within 10 working days of receipt of the enquiry

Please refer to section 7.8 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Requests for WRI provided within 10 work days	# of Requests for WRI	% of Requests for WRI provided within 10 working days
January	45	45	100.00
February	42	42	100.00
March	33	33	100.00
April	47	50	94.00
May	44	44	100.00
June	68	68	100.00
July	62	62	100.00
August	88	88	100.00
September	51	51	100.00
October	41	41	100.00
November	57	57	100.00
December	54	54	100.00

WRI Annual Total

Total WRI Request in 10 days	Total WRI Request	WRI Annual Total Percentage
632	635	99.50

Emergency Response - Urban

The percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 60 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Emergency Urban Calls within 60 Minutes	# of Emergency Urban Calls	% ERU 60 Minutes

January	4	4	100.00
February	1	1	100.00
March	0	0	0.00
April	2	2	100.00
May	3	3	100.00
June	3	3	100.00
July	2	2	100.00
August	4	4	100.00
September	3	3	100.00
October	3	3	100.00
November	1	1	100.00
December	0	0	0.00

ERU Annual Total

Total # of ER Urban OnSite within 60 min	Total # of ER Urban Calls	ER Urban Annual Total Percentage
26	26	100.00

Emergency Response - Rural

The percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 120 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Emergency Rural Calls within 120 minutes	# of Emergency Rural Calls	% ERR 120 minutes
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

ERR Annual Total

Total # of ERR Calls OnSite 120min	Total # of ER Rural calls	ER Rural Annual Total Percentage
0	0	0.00

Service Reliability Indices

Includes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please include all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

CAIDI - Customer Average Interruption Duration Index

OEB Approved Standard: Within the range of 3 years historical performance.

Total number of customers equals the number of customer accounts served by the distributor in the reporting month

Month	Total Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Total Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/(3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	102	66	30,787	0.00	0.00	1.55
February	2,104	1,706	30,801	0.07	0.06	1.23
March	202	355	30,810	0.01	0.01	0.57
April	415	375	30,852	0.01	0.01	1.11
May	185	218	30,874	0.01	0.01	0.85
June	271	272	30,905	0.01	0.01	1.00
July	222	242	30,931	0.01	0.01	0.92
August	358	477	30,983	0.01	0.02	0.75
September	295	389	31,060	0.01	0.01	0.76
October	182	562	31,129	0.01	0.02	0.32
November	23	21	31,237	0.00	0.00	1.10
December	1,259	643	31,290	0.04	0.02	1.96

Service Reliability Indices Annual Totals and Average

Total Customer Hours of Interruptions: 5,618

Total Customer Interruptions: 5,326

Average # of Customers: 30,971.58

Total SAIDI (1)/ (3): 0.18

Total SAIFI (2)/(3): 0.17

Total CAIDI (4)/(5): 1.05

Loss of Sply Adjusted Service Reliability Indices

Excludes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please deduct interruptions caused by Loss of Supply from all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

CAIDI - Customer Average Interruption Duration Index

Total number of customers equals the number of customer accounts served by the distributor in the reporting month

OEB Approved Standard: Within the range of 3 years historical performance.

Month	Adjusted Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200	Adjusted Customer Interruptions (i.e., 100 customers interrupted 2	Total # of Customers (i.e., Not just affected customer, total	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)

	Customer = 50 hours of interruption)	times = 200 customers interrupted)	customers served for the month)	(3)	(3)	(5)
January	102	66	30,787	0.00	0.00	1.55
February	2,104	1,706	30,801	0.07	0.06	1.23
March	202	355	30,810	0.01	0.01	0.57
April	415	375	30,852	0.01	0.01	1.11
May	185	218	30,874	0.01	0.01	0.85
June	271	272	30,905	0.01	0.01	1.00
July	222	242	30,931	0.01	0.01	0.92
August	358	477	30,983	0.01	0.02	0.75
September	208	369	31,060	0.01	0.01	0.56
October	182	562	31,129	0.01	0.02	0.32
November	23	21	31,237	0.00	0.00	1.10
December	1,259	643	31,290	0.04	0.02	1.96

Service Reliability Indices Annual Totals and Average

Adjusted Customer Hours of Interruptions
5,531

Adjusted Customer Interruptions
5,306

Average # of Customers
30,971.58

Total Loss of Supply Adjusted SAIDI (1)/ (3)
0.18

Total Loss of Supply Adjusted SAIFI (2)/(3)
0.17

Total Loss of Supply Adjusted CAIDI (4)/(5)
1.04

Momentary Average Interruption Frequency Index

Distributors that do not have the system capability that enables them to capture or measure MAIFI are exempted from this reporting requirement.

All planned and unplanned interruptions should be used to calculate this index.

Month	Momentary Interruption	Number of Customers served	MAIFI (1)/(2)
No Records			

Total Momentary Interruption
0.00

Average Number of Customers Served

Total Momentary Average Interruption Frequency Index (MAIFI)

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Report Summary

Filing Year: 2009

Filing Form Name: 2.1.4

Filing Form Description: Service

RRR Filing No: 6,478

Reporting Period: January- 2009Newmarket - Tay Power Distribution Ltd., Newmarket: Corporation; ED-2007-0624; ;

Extension Granted:

Report Version: 0

Due: February 2, 2009

Extension Deadline:

Status: Submitted

Submitter Name: David Weir

Submitted On: February 2, 2009

Licence Type: Distributor

Expiry Date: May 1, 2010

New Connection - Low Voltage (LV)

The percentage of new low voltage (<750 Volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code.

OEB Approved Standard: 90% or more

Month	# of new LV Services connected within 5 Days	# of new LV Services connected	% of # of new LV Services connected within 5 days
January	32	32	100.00
February	26	27	96.30
March	22	23	95.65
April	36	36	100.00
May	68	68	100.00
June	41	45	91.11
July	68	68	100.00
August	73	73	100.00
September	102	102	100.00
October	107	113	94.69
November	48	53	90.57
December	56	56	100.00

New Connection - LV Annual Total

Total # of new LV Services connected within 5 Days: 679

Total # of new LV Services connected: 696

NC LV AnnualTotal Percentage: 97.60

New Connection - High Voltage(HV)

The percentage of new high voltage (>=750 Volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of new HV Services connected within 10 Days	# of new HV Services connected	% of new HV Services connected within 10 Days
January	0	0	0.00
February	1	1	100.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

New Connection - HV Annual Total

Total # of new HV Services connected within 10 Days	Total # of new HV Services connected	NC HV Annual Total Percentage
1	1	100.00

Appointments Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code

Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of Appointments scheduled as required	# of Appointment requests received in the month	Percentage Appointments Scheduled as Required
No Records			

Appointment Scheduled - Annual Total

Total # of Scheduled	Total # of Requested	Appointments Scheduled Total Percentage

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment is scheduled as required and the appointment date and time is met.

Please refer to section 7.4 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of visits to customer's site where Appointment scheduled and completed as required	# of Appointments with customer/representative	% Appointment Met
January	15	15	100.00
February	9	9	100.00
March	9	10	90.00
April	10	10	100.00
May	15	15	100.00
June	8	8	100.00

July	17	17	100.00
August	13	13	100.00
September	14	14	100.00
October	11	11	100.00
November	16	16	100.00
December	9	9	100.00

Appointments Met - Annual Total

Total # of Appointments Met	Total # of Appointments requiring meeting with customer	Appointments Met Annual Total Percentage
146	147	99.30

Rescheduling a Missed Appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed

Please refer to section 7.5 of the Distribution System Code

OEB Approved Standard: 100%

Month	# of Appointments Rescheduled as Required	# of Missed/About to be Missed Appointments	% Appointments Rescheduled
No Records			

Appointments Rescheduled - Annual Total

Total # of Appointments Rescheduled	Total # of Appointments Missed/About to be Missed	Appointments Rescheduled Annual Total Percentage

Telephone Accessibility (TelefonServicFactor TSF)

The percentage of calls to the utility's general inquiry number that are answered in person within 30 seconds.

Please refer to section 7.6 of the Distribution System Code

OEB Approved Standard: 65% or more

Month	# of General Inquiry Telephone Calls Answered within 30 Sec	# of General inquiry Calls	% TSF
January	2,663	3,097	85.99
February	1,939	2,160	89.77
March	2,299	2,364	97.25
April	2,639	2,839	92.96
May	2,236	2,422	92.32
June	2,211	2,712	81.53
July	2,336	2,693	86.74
August	2,117	2,373	89.21
September	1,890	2,303	82.07
October	2,195	2,597	84.52
November	1,910	2,206	86.58
December	1,852	1,996	92.79

Telephone Accessibility Annual Total

Total # General Inqury Telephone Calls

Total # General Inquiry Telephone Calls

Answered within 30 Sec	Total # of General Inquiry Telephone Calls	Percentage
26,287	29,762	88.30

Telephone Call Abandon Rate

The percentage of telephone calls that are abandoned before they are answered

Please refer to section 7.7 of the Distribution System Code

OEB Approved Standard: 10% or less

Month	# of Telephone Calls Unanswered or Abandoned after 30 seconds	Total # of Telephone Calls Received	% Telephone Calls Abandoned
No Records			

Total # of Calls Missed	Total # of Telephone Calls Received	Telephone Calls Abandoned - Annual Total Percentage

Written Responses to Enquiries

The percentage of customer enquiries requiring a written response where the response is provided within 10 working days of receipt of the enquiry

Please refer to section 7.8 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Requests for WRI provided within 10 work days	# of Requests for WRI	% of Requests for WRI provided within 10 working days
January	112	112	100.00
February	52	52	100.00
March	48	48	100.00
April	75	75	100.00
May	67	67	100.00
June	50	50	100.00
July	59	59	100.00
August	45	45	100.00
September	50	50	100.00
October	37	37	100.00
November	50	50	100.00
December	39	39	100.00

WRI Annual Total

Total WRI Request in 10 days	Total WRI Request	WRI Annual Total Percentage
684	684	100.00

Emergency Response - Urban

The percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 60 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Emergency Urban Calls within 60 Minutes	# of Emergency Urban Calls	% ERU 60 Minutes

January	1	1	100.00
February	4	4	100.00
March	0	0	0.00
April	1	1	100.00
May	1	1	100.00
June	2	2	100.00
July	4	4	100.00
August	2	2	100.00
September	1	1	100.00
October	2	2	100.00
November	5	5	100.00
December	0	0	0.00

ERU Annual Total

Total # of ER Urban OnSite within 60 min	Total # of ER Urban Calls	ER Urban Annual Total Percentage
23	23	100.00

Emergency Response - Rural

The percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 120 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Emergency Rural Calls within 120 minutes	# of Emergency Rural Calls	% ERR 120 minutes
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

ERR Annual Total

Total # of ERR Calls OnSite 120min	Total # of ER Rural calls	ER Rural Annual Total Percentage
0	0	0.00

Service Reliability Indices

Includes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please include all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

CAIDI - Customer Average Interruption Duration Index

OEB Approved Standard: Within the range of 3 years historical performance.

Total number of customers equals the number of customer accounts served by the distributor in the reporting month

Month	Total Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Total Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/ (3)	CAIDI (4)/ (5)
January	3,606	2,130	31,299	0.12	0.07	1.69
February	1,374	896	31,329	0.04	0.03	1.53
March	30	16	31,335	0.00	0.00	1.88
April	687	436	31,380	0.02	0.01	1.58
May	2,269	666	31,488	0.07	0.02	3.41
June	8,355	1,324	31,528	0.27	0.04	6.31
July	1,452	978	31,618	0.05	0.03	1.48
August	25	66	31,709	0.00	0.00	0.38
September	3,619	1,831	31,760	0.11	0.06	1.98
October	133	267	31,861	0.00	0.01	0.50
November	2,832	738	31,916	0.09	0.02	3.84
December	18,072	6,652	31,967	0.57	0.21	2.72

Service Reliability Indices Annual Totals and Average

Total Customer Hours of Interruptions	Total Customer Interruptions	Average # of Customers
42,454	16,000	31,599.17
Total SAIDI (1)/ (3)	**Total SAIFI (2)/(3)**	**Total CAIDI (4)/(5)**
1.34	0.51	2.65

Loss of Sply Adjusted Service Reliability Indices

Excludes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please deduct interruptions caused by Loss of Supply from all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

CAIDI - Customer Average Interruption Duration Index

Total number of customers equals the number of customer accounts served by the distributor in the reporting month

OEB Approved Standard: Within the range of 3 years historical performance.

Month	Adjusted Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200	Adjusted Customer Interruptions (i.e., 100 customers interrupted 2	Total # of Customers (i.e., Not just affected customer, total	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)

	Customer = 50 hours of interruption)	times = 200 customers interrupted)	customers served for the month)	(3)	(3)	(5)
January	3,606	2,130	31,299	0.12	0.07	1.69
February	1,374	896	31,329	0.04	0.03	1.53
March	30	16	31,335	0.00	0.00	1.88
April	687	436	31,380	0.02	0.01	1.58
May	2,269	666	31,488	0.07	0.02	3.41
June	705	424	31,528	0.02	0.01	1.66
July	1,452	978	31,618	0.05	0.03	1.48
August	25	66	31,709	0.00	0.00	0.38
September	541	292	31,760	0.02	0.01	1.85
October	133	267	31,861	0.00	0.01	0.50
November	32	38	31,916	0.00	0.00	0.84
December	18,072	6,652	31,967	0.57	0.21	2.72

Service Reliability Indices Annual Totals and Average

Adjusted Customer Hours of Interruptions: 28,926

Adjusted Customer Interruptions: 12,861

Average # of Customers: 31,599.17

Total Loss of Supply Adjusted SAIDI (1)/ (3): 0.92

Total Loss of Supply Adjusted SAIFI (2)/(3): 0.41

Total Loss of Supply Adjusted CAIDI (4)/(5): 2.25

Momentary Average Interruption Frequency Index

Distributors that do not have the system capability that enables them to capture or measure MAIFI are exempted from this reporting requirement.

All planned and unplanned interruptions should be used to calculate this index.

Month	Momentary Interruption	Number of Customers served	MAIFI (1)/(2)
No Records			

Total Momentary Interruption: 0.00

Average Number of Customers Served:

Total Momentary Average Interruption Frequency Index (MAIFI):

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* Submit Form: No

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Report Summary

Filing Year	Filing Form Name	Filing Form Description
2010	2.1.4	Service

RRR Filing No	Reporting Period	Extension Granted
379	January- 2010Newmarket - Tay Power Distribution Ltd., Newmarket: Corporation; ED-2007-0624; ;	

Report Version	Due	Extension Deadline
0	March 31, 2010	

Status	Submitter Name	Submitted On
Submitted	David Weir	April 6, 2010

Licence Type		Expiry Date
Distributor		May 1, 2010

New Connection - Low Voltage (LV)

The percentage of new low voltage (<750 Volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code.

OEB Approved Standard: 90% or more

Month	# of new LV Services connected within 5 Days	# of new LV Services connected	% of # of new LV Services connected within 5 days
January	49	50	98.00
February	50	50	100.00
March	77	78	98.72
April	64	64	100.00
May	61	61	100.00
June	37	37	100.00
July	64	64	100.00
August	58	58	100.00
September	73	74	98.65
October	65	66	98.48
November	57	57	100.00
December	40	40	100.00

New Connection - LV Annual Total

Total # of new LV Services connected within 5 Days	Total # of new LV Services connected	NC LV AnnualTotal Percentage
695	699	99.40

New Connection - High Voltage(HV)

The percentage of new high voltage (>=750 Volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of new HV Services connected within 10 Days	# of new HV Services connected	% of new HV Services connected within 10 Days
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

New Connection - HV Annual Total

Total # of new HV Services connected within 10 Days	Total # of new HV Services connected	NC HV Annual Total Percentage
0	0	0.00

Appointments Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code

Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of Appointments scheduled as required	# of Appointment requests received in the month	Percentage Appointments Scheduled as Required
January	12	12	100.00
February	11	11	100.00
March	33	33	100.00
April	64	64	100.00
May	79	79	100.00
June	74	74	100.00
July	75	75	100.00
August	59	59	100.00
September	64	64	100.00
October	43	43	100.00
November	39	39	100.00
December	9	9	100.00

Appointment Scheduled - Annual Total

Total # of Scheduled	Total # of Requested	Appointments Scheduled Total Percentage
562	562	100.00

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment is scheduled as required and the appointment date and time is met.

Please refer to section 7.4 of the Distribution System Code

OEB Approved Standard: 90% or more

Month	# of visits to customer's site where Appointment scheduled and completed as required	# of Appointments with customer/representative	% Appointment Met
January	12	12	100.00
February	11	11	100.00
March	33	33	100.00
April	64	64	100.00
May	79	79	100.00
June	74	74	100.00
July	75	75	100.00
August	59	59	100.00
September	64	64	100.00
October	43	43	100.00
November	39	39	100.00
December	9	9	100.00

Appointments Met - Annual Total

Total # of Appointments Met	Total # of Appointments requiring meeting with customer	Appointments Met Annual Total Percentage
562	562	100.00

Rescheduling a Missed Appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed

Please refer to section 7.5 of the Distribution System Code

OEB Approved Standard: 100%

Month	# of Appointments Rescheduled as Required	# of Missed/About to be Missed Appointments	% Appointments Rescheduled
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Appointments Rescheduled - Annual Total

Total # of Appointments Rescheduled	Total # of Appointments Missed/About to be Missed	Appointments Rescheduled Annual Total Percentage
0	0	0.00

Telephone Accessibility (TelefonServicFactor TSF)

The percentage of calls to the utility's general inquiry number that are answered in person within 30 seconds.

Please refer to section 7.6 of the Distribution System Code

OEB Approved Standard: 65% or more

Month	# of General Inquiry Telephone Calls Answered within 30 Sec	# of General inquiry Calls	% TSF
January	2,648	2,846	93.04
February	2,512	2,657	94.54
March	3,212	3,338	96.23
April	2,849	3,116	91.43
May	2,761	2,948	93.66
June	3,260	3,611	90.28
July	3,314	3,747	88.44
August	2,953	3,379	87.39
September	2,880	3,392	84.91
October	2,815	3,482	80.84
November	2,746	3,300	83.21
December	2,177	2,399	90.75

Telephone Accessibility Annual Total

Total # General Inqury Telephone Calls Answered within 30 Sec	Total # of General Inquiry Telephone Calls	Total # General Inquiry Telephone Calls Percentage
34,127	38,215	89.30

Telephone Call Abandon Rate

The percentage of telephone calls that are abandoned before they are answered

Please refer to section 7.7 of the Distribution System Code

OEB Approved Standard: 10% or less

Month	# of Telephone Calls Unanswered or Abandoned after 30 seconds	Total # of Telephone Calls Received	% Telephone Calls Abandoned
January	18	2,846	0.63
February	13	2,657	0.49
March	10	3,338	0.30
April	24	3,116	0.77
May	23	2,948	0.78
June	40	3,611	1.11
July	44	3,747	1.17
August	60	3,379	1.78
September	118	3,392	3.48

October	118	3,482	3.39
November	102	3,300	3.09
December	25	2,399	1.04

Total # of Calls Missed	Total # of Telephone Calls Received	Telephone Calls Abandoned - Annual Total Percentage
595	38,215	1.60

Written Responses to Enquiries

The percentage of customer enquiries requiring a written response where the response is provided within 10 working days of receipt of the enquiry

Please refer to section 7.8 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Requests for WRI provided within 10 work days	# of Requests for WRI	% of Requests for WRI provided within 10 working days
January	53	53	100.00
February	47	47	100.00
March	77	77	100.00
April	76	76	100.00
May	65	65	100.00
June	71	71	100.00
July	103	103	100.00
August	92	92	100.00
September	53	53	100.00
October	72	72	100.00
November	60	60	100.00
December	8	8	100.00

WRI Annual Total

Total WRI Request in 10 days	Total WRI Request	WRI Annual Total Percentage
777	777	100.00

Emergency Response - Urban

The percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 60 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Emergency Urban Calls within 60 Minutes	# of Emergency Urban Calls	% ERU 60 Minutes
January	2	2	100.00
February	3	3	100.00
March	0	0	0.00
April	1	1	100.00
May	2	2	100.00

June	3	3	100.00
July	0	0	0.00
August	2	2	100.00
September	1	1	100.00
October	1	1	100.00
November	3	3	100.00
December	2	2	100.00

ERU Annual Total

Total # of ER Urban OnSite within 60 min	Total # of ER Urban Calls	ER Urban Annual Total Percentage
20	20	100.00

Emergency Response - Rural

The percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 120 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: 80% or more

Month	# of Emergency Rural Calls within 120 minutes	# of Emergency Rural Calls	% ERR 120 minutes
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

ERR Annual Total

Total # of ERR Calls OnSite 120min	Total # of ER Rural calls	ER Rural Annual Total Percentage
0	0	0.00

Service Reliability Indices

Includes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please include all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

CAIDI - Customer Average Interruption Duration Index

OEB Approved Standard: Within the range of 3 years historical performance.

Total number of customers equals the number of customer accounts served by the distributor in the reporting month

Month	Total Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Total Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/(3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	110	70	31,912	0.00	0.00	1.57
February	66	89	31,975	0.00	0.00	0.74
March	221	166	32,055	0.01	0.01	1.33
April	2,337	2,044	32,127	0.07	0.06	1.14
May	274	794	32,189	0.01	0.02	0.35
June	3,885	2,331	32,276	0.12	0.07	1.67
July	787	563	32,278	0.02	0.02	1.40
August	4,843	2,376	32,314	0.15	0.07	2.04
September	73	106	32,401	0.00	0.00	0.69
October	201	866	32,463	0.01	0.03	0.23
November	121	196	32,514	0.00	0.01	0.62
December	46	47	32,553	0.00	0.00	0.98

Service Reliability Indices Annual Totals and Average

Total Customer Hours of Interruptions	Total Customer Interruptions	Average # of Customers
9,721	9,648	32,254.75

Total SAIDI (1)/ (3)	Total SAIFI (2)/(3)	Total CAIDI (4)/(5)
0.30	0.30	1.01

Loss of Sply Adjusted Service Reliability Indices

Excludes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please deduct interruptions caused by Loss of Supply from all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

CAIDI - Customer Average Interruption Duration Index

Total number of customers equals the number of customer accounts served by the distributor in the reporting month

OEB Approved Standard: Within the range of 3 years historical performance.

Month	Adjusted Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Adjusted Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/(3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	110	70	31,912	0.00	0.00	1.57
February	66	89	31,975	0.00	0.00	0.74
March	221	166	32,055	0.01	0.01	1.33
April	2,337	2,044	32,127	0.07	0.06	1.14

May	274	794	32,189	0.01	0.02	0.35
June	3,885	2,331	32,276	0.12	0.07	1.67
July	787	563	32,278	0.02	0.02	1.40
August	220	835	32,314	0.01	0.03	0.26
September	73	106	32,401	0.00	0.00	0.69
October	201	866	32,463	0.01	0.03	0.23
November	121	196	32,514	0.00	0.01	0.62
December	46	47	32,552	0.00	0.00	0.98

Service Reliability Indices Annual Totals and Average

Adjusted Customer Hours of Interruptions	Adjusted Customer Interruptions	Average # of Customers
8,074	8,107	32,254.67

Total Loss of Supply Adjusted SAIDI (1)/ (3)	Total Loss of Supply Adjusted SAIFI (2)/(3)	Total Loss of Supply Adjusted CAIDI (4)/(5)
0.25	0.25	1.00

Momentary Average Interruption Frequency Index

Distributors that do not have the system capability that enables them to capture or measure MAIFI are exempted from this reporting requirement.

All planned and unplanned interruptions should be used to calculate this index.

Month	Momentary Interruption	Number of Customers served	MAIFI (1)/(2)
January	0.00	0	0.00
February	0.00	0	0.00
March	0.00	0	0.00
April	0.00	0	0.00
May	0.00	0	0.00
June	0.00	0	0.00
July	0.00	0	0.00
August	0.00	0	0.00
September	0.00	0	0.00
October	0.00	0	0.00
November	0.00	0	0.00
December	0.00	0	0.00

Total Momentary Interruption	Average Number of Customers Served	Total Momentary Average Interruption Frequency Index (MAIFI)
0.00	0.00	0.00

Submit?

* Submit Form

No

Exhibit 3:

REVENUE

Exhibit 3: Revenue

Tab 1 (of 3): Throughput Revenue

OVERVIEW AND VOLUMETRIC TREND TABLE

For 2010, The Applicant's combined forecasted revenues recovered solely through its currently approved distribution rates will be $14,851,593 (excluding low voltage charges and smart meter rate riders or adders in both service areas). This amount has been estimated by applying the OEB authorized distribution rates for the Newmarket Service area and the Tay service area to their respective forecasted consumption and customer counts and then combining the resulting individual revenues. The load forecast for consumption, demand, and projected customers counts was prepared by Elenchus Research Associates (Elenchus) and is attached as Exhibit 3, Tab 1, Schedule 1, Attachment 1.

The forecasted 2010 distribution revenues are only $67,185 over the 2008 actual amounts. (2008-$14,784,408 – 2010 $14,851,593)

	2007	2008	2009 Bridge (12 mons @ 2009 rates)	2010 Test (12 mons @ 2009 Rates)	2010 Test (12 mons @ 2010 Rates)
Residential	7,996,556	8,104,474	8,315,769	8,415,172	9,926,666
GS<50	2,348,127	2,361,827	2,361,373	2,373,704	2,792,019
USL	29,702	29,951	25,033	25,033	29,445
GS>50	4,164,664	4,214,383	3,844,240	3,730,931	4,388,428
Street Lights	60,346	61,738	288,727	292,715	315,800
Sentinel Lights	12,035	12,035	14,597	14,038	16,508
Total	$14,611,430	$14,784,408	$ 14,849,739	$14,851,593	$ 17,468,866

The main two reasons why revenues have not increased as much as forecast over this two year period is that The Applicant has lost four large GS>50 customers including The Applicant's largest customer; an automotive parts manufacturer. The amount of lost revenue from these large customers totals $380,000.

In addition to these general service losses in the GS>50 class, the average weather normalized consumption of the residential consumer has decreased by 258 Kwh per annum from 9,616 Kwh in 2008 to 9,358 Kwh in 2010.

APPROACH TO WEATHER NORMALIZED LOAD FORECAST

Load Forecasting Methodology and Data

Elenchus has prepared a weather normalized 2010 load forecast. A load forecast report is provided at Exhibit 3, Tab 1, Schedule 2, Attachment 1 in which Elenchus documents:

- the proposed weather normalization methodology;
- the data relied on to estimate weather normalized loads; and
- Elenchus' proposed 2010 load consumption forecast and number of customers.

As a result of the early adoption of smart meters, the Applicant was able to provide Elenchus with the following data for both service areas:

- monthly wholesale energy;
- monthly energy deliveries by customer class;
- monthly kW for classes with demand charges; and
- monthly number of customers by customer class.

Also, during 2009, three large GS>50 kW class customers ceased operations. Cam Tool and Die (automotive) and Exopack (packaging) have closed completely. Rimply (automotive) has ceased operations. Another large customer, Reiningers (automotive) has reduced consumption and is currently under bankruptcy protection. It was necessary for Elenchus to acquire detailed billing data from The Applicant for these customers for the past 5 years and to remove them from the class historic data; this was achieved by subtracting their respective metered load data from that of the General Service > 50 kW customer class. Because there is no known load loss in Tay's service area no data adjustments are proposed to the historic consumption for customers formerly served by Tay.

The load data for each service area was used to develop load forecast regression equations for wholesale 'weather sensitive' load using the following explanatory variables:

- actual weather data expressed as Heating Degree Days ("HDD") and Cooling Degree Days ("CDD");
- economic activity data in the form of monthly historic employment levels; and
- actual calendarization data that describes the number of peak days in a month (Newmarket) or the number of days in the month (Tay).

The estimated regression equations and statistics are provided at page 5 of the report. The proposed econometric models are statistically valid and are supported by acceptable diagnostic statistics. The model was evaluated for 'goodness of fit' using a 'within sample error' methodology. Briefly, the actual weather, economic and calendarization data was input to the model and the estimated annual 'weather sensitive' load was compared to the actual annual 'weather sensitive' load. This comparison shows that the model's forecasting error is approximately 0.2% for NTPDL as a whole.

Elenchus forecast annual 'weather sensitive' energy deliveries by using normal weather, defined as the 1999-2008 ten year average, forecast change in employment levels and appropriate calendarization for the 2010 test year in the regression equation. Elenchus averaged the employment forecasts of four chartered banks available at the time of forecast to estimate the change in employment in The Applicant's service areas.

Elenchus used the ratio of The Applicant's historic customer class data on billed energy (adjusted for annual unbilled error) and billed demand to develop an annual kW/kWh ratio. This historic relationship was applied to the forecast energy deliveries by customer class to estimate billed demand for each demand billed customer class.

Subsequent Adjustments to ERA's Load Forecast

CDM

The Applicant has further adjusted the load forecast for the expected future achievement of CDM results in either of its service areas. The Applicant intends to participate in all OPA sponsored and administered CDM programs during 2010.

The Applicant's past CDM achievements have been documented in its CDM annual reports that were filed previously with the OEB; these reports were provided in The Applicants prior cost of service filing EB 2007-0766. They demonstrate that over the period 2006-08 the Applicant realized:

- an 11 fold increase in peak kW savings, which is significantly higher than that forecast by the OPA; and
- a doubling of the energy savings achievements, which is significantly lower than that forecast by the OPA.

These results reflect the delivery of CDM programs in past periods that were targeted to reducing or shifting peak demand and to help to alleviate system overloading issues that resulted from growth in the area. Consumers were trying to reduce their "carbon footprint" as evidenced in The Applicant's customer satisfaction reports.

In 2010, The Applicant expects that its customers will continue to realize CDM savings and look for ways reduce their peak consumption. These changes in demand will be driven by the same reasons as in the past; however now reductions and shifts in consumption will also stem from customers trying to reduce their bills due to the increase cost of electricity and the harmonization of PST and GST into the HST. The Applicant will request the 2009 and 2010 OPA results achieved through the Lost Revenue Adjustment Mechanism (LRAM) in a future cost of service filing. In this application, The Applicant is requesting a LRAM for CDM results for the years ending 2008. This calculation is presented in the deferral account chapter. The Applicant is not requesting any additional funds in this application to run its CDM programs.

Time of Use Commodity Rates ("TOU")

Based on a current study by Navigant Consulting ("Navigant") The Applicant is not adjusting it's load forecast for time of use commodity pricing. This study found that TOU does not materially alter residential consumption. Residential consumers shifted the timing of their consumption and reduced peak demand, but they have not materially reduced the amount of electricity consumed. Therefore it is not appropriate to further adjust the load forecast for the effects of TOU.

The Applicant started converting customers to TOU pricing in 2007. By September of 2009, all eligible residential customers in The Applicant's service area were being charged TOU pricing and receiving TOU bills.

In a pilot study of the effects of TOU pricing approved by the OEB in 2008 The Applicant engaged Navigant to analyze the impact of Smart Meters and TOU pricing on consumers consumption habits. The original study was based upon 250 customers that were switched to TOU billing. In that study Navigant's findings with respect to an overall conservation effect were consistent with the current study noted above (this report was previously filed with EB-2008-0766. The current study was based upon a greater sample of customers who had been experiencing TOU pricing for an extended period of time. A copy of this report is provided as an appendix.

Thus The Applicant has adopted the load forecast produced by the econometric model prepared by Elenchus.

Weather Normalized Distribution System Load Forecast – 2010 Test Year

Prepared for

Newmarket-Tay Power Distribution Ltd.

March 2010

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Newmarket-Tay Power Distribution Ltd.'s (NTPDL) rebasing rate application for 2010 rates. A weather normal load forecast is developed for the 2010 test year and weather normalized historical consumption is also derived (including 2009 for which actual consumption is now available).

Short-term variation in monthly electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors, such as holidays, weekdays, and number of days in the month. We have incorporated variables, as appropriate, to account for these factors in considering NTPDL's load and correcting for weather anomalies.

FORECASTING APPROACH

Monthly class specific billing data is generally available for all rate classes in both the Newmarket and Tay distribution service territory served by NTPDL from January 2002, as well as monthly wholesale deliveries, measured at the point-of-delivery. However, there is no specific algorithm available to NTPDL that allows pro-ration or other forms of adjustment to correct for the effect of monthly unbilled energy in the class specific billing data. For both Newmarket and Tay, monthly unbilled energy appears to be a significant issue. As a result, class-specific billing data does not always correlate with wholesale consumption, nor does it correlate as well as expected with monthly observed weather. We have adjusted class specific consumption for unbilled energy on an annual basis. However, it is not possible to do this on a monthly basis. For these reasons, we have opted to base the weather normal forecast for NTPDL on "weather sensitive" monthly wholesale purchases for Newmarket and Tay. Once smart meters are universally deployed and a workable data warehouse is available, development of class specific weather normal factors should not be so problematic.

NTPDL also requires that separate accounting for the Newmarket service territory of NTPDL be available. Due to this requirement, a separate forecasting equation for both Newmarket and Tay is developed. The sum of consumption in Newmarket and Tay is equal to the total NTPDL consumption.

Finally, there is one further point that needs consideration. Newmarket, like many communities in south-western Ontario, is significantly exposed to the manufacturing downturn (and specifically, the automotive sector). Three large GS>50 kW class customers ceased operations in 2009. Cam Tool and Die (automotive) and Exopack (packaging) have closed completely. Rimply (automotive) has ceased operations. Another large customer, Reiningers (automotive) has reduced consumption. Due to the large reduction in consumption in the GS>50 kW class and reduced wholesale purchases for the utility, monthly wholesale energy for Newmarket has been defined to exclude these four GS>50 customers' consumption, as well as the non-weather sensitive consumption of the street lighting, sentinel lighting and USL customer classes. This adjusted wholesale load is termed WSL or "weather sensitive load". Monthly consumption for the four GS>50 kW customers discussed is available from April 2004. The assumption is that these manufacturing loads are not weather sensitive. Once the weather sensitive portion of GS>50 class kWh is derived, the consumption associated with these customers is added back to the class.

The forecast for Tay is based on monthly weather sensitive wholesale deliveries (WSL) to the Tay Distribution System from January 2002 to December 2008. WSL is defined as monthly wholesale kWh less monthly street lighting, sentinel lighting and USL. Details on both Newmarket and Tay are outlined in the next section

2 ENERGY FORECAST USING WHOLESALE KWH DELIVERIES

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For both Newmarket and Tay, we have used monthly HDD and CDD as reported at Pearson International Airport near Toronto.

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. For Newmarket, we have used the monthly full-time employment levels for Toronto (Census Metropolitan Area), as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v3473200). Newmarket is a part of the Toronto CMA. For Tay, we have used the monthly full-time employment levels for Ontario (CANSIM series v2054816).

The number of peak days (non-holiday week days) is also included as an explanatory variable for Newmarket. For holidays, we have included New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, August Civic Holiday (Simcoe Day), Labour Day, Thanksgiving Day, Christmas and Boxing Day. From 2008, we have included the Ontario Family Day holiday in February, but we have not included Remembrance Day in November. For Tay, the number of peak days was not significant; however, the number of days in the month was significant and was used as an explanatory variable.

Using these data, a multiple regression analysis was used to develop an equation describing the relationship between monthly actual energy deliveries and the explanatory variables. For Newmarket, 69 monthly observations for the period of April 2004[1] to December 2009 were used to develop the equation. For Tay, 96 monthly observations from the period January 2002 to December 2009 were used.

The regression results for both Newmarket and Tay are summarized in the tables below.

[1] Interval meter data for the customers referred to in Section 1 is available back to April 2004.

Table 1 – Newmarket and Tay Wholesale kWh Forecast Equations

Newmarket WSL kWh

OLS estimates using the 69 observations 2004:04-2009:12
Dependent variable: NM_WSLkWh
R-squared = 0.8818
Adjusted R-squared = 0.8745
F-statistic (4, 64) = 119.399 P-value(F) 6.11e-29
Durbin-Watson statistic = 1.91 Theil's U = 0.29869

	coefficient	t-stat	p-value
const	11,863,287.26	1.565	0.122478
HDD_Tor	15,189.31	15.554	2.01E-23
CDD_Tor	106,084.10	20.401	1.05E-29
Peakdays	510,793.53	2.900	0.005106
FTE_Tor	10,040.87	3.571	0.000682

Tay WSL kWh

OLS estimates using the 96 observations 2002:01-2009:12
Dependent variable: Tay_WSLkWh
R-squared = 0.9535
Adjusted R-squared = 0.9515
F(4, 91) = 466.47 (P-value(F) = 1.04e-59)
Durbin-Watson = 1.34 Theil's U = 0.26811

	coefficient	t-stat	p-value
const	-1,852,881.9	-3.20	0.0019
HDD_Tor	2,863.9	40.44	6.06E-60
CDD_Tor	6,661.3	18.46	1.63E-32
MonthDays	106,123.9	6.62	2.46E-09
FTE_Ont	256.2	3.74	0.000316

Fitted vs. actual observations are plotted in the charts below:

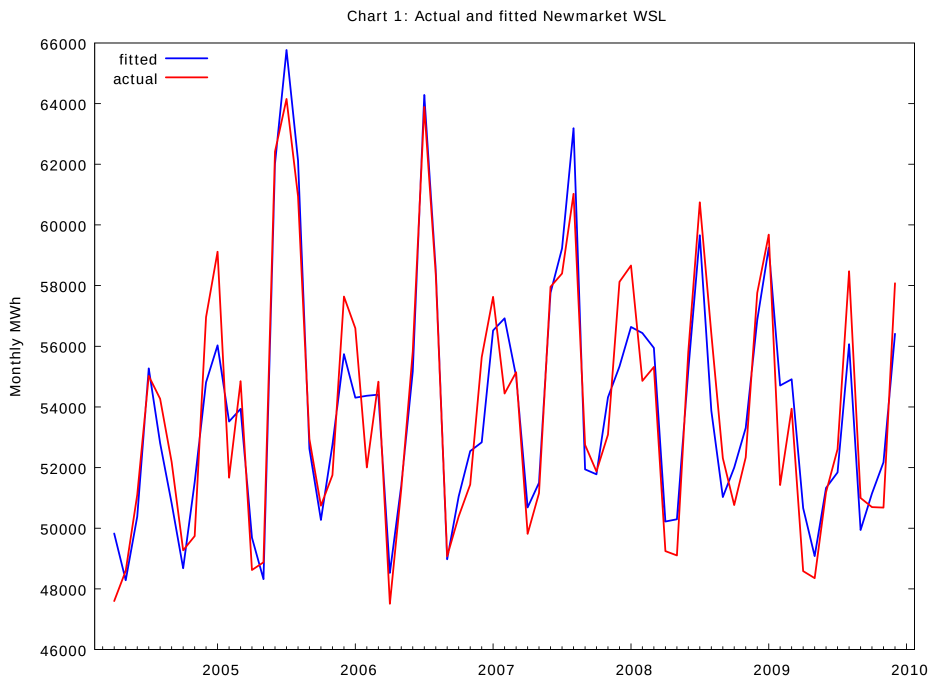


Chart 1: Actual and fitted Newmarket WSL
fitted
actual
Monthly MWh
66000
64000
62000
60000
58000
56000
54000
52000
50000
48000
46000
2005
2006
2007
2008
2009
2010

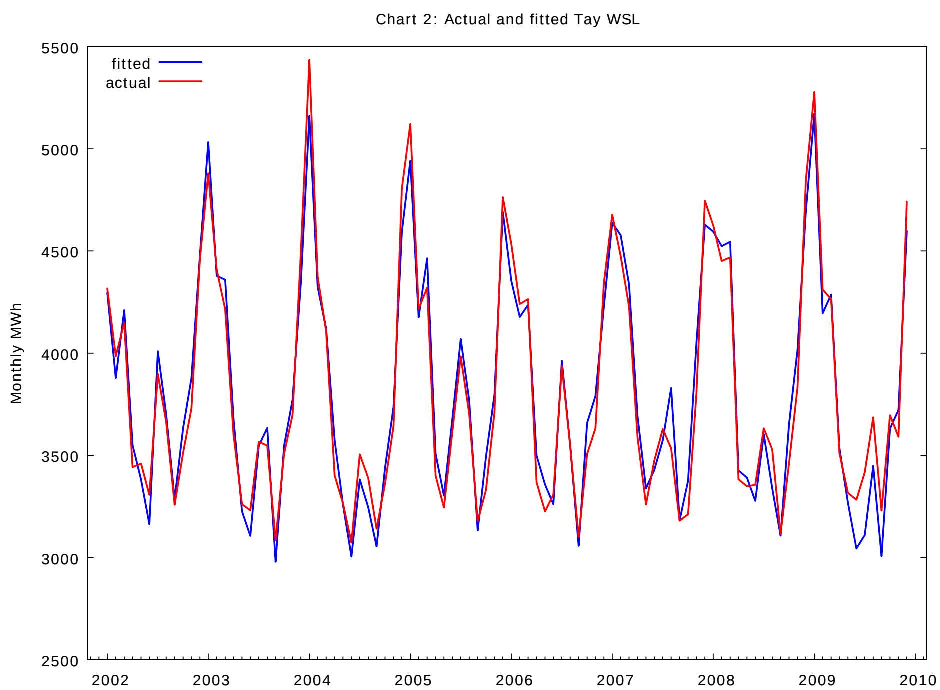


Chart 2: Actual and fitted Tay WSL
fitted
actual
Monthly MWh
5500
5000
4500
4000
3500
3000
2500
2002
2003
2004
2005
2006
2007
2008
2009
2010

Annual estimates using actual weather are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is 0.2% with the largest absolute error on an annual estimate at 0.5%. Separate results for Newmarket and Tay are also presented.

Table 2 – Actual WSL kWh vs. Estimates, NTPDL

Year	*Actual kWh*	*Predicted kWh*	*Absolute % Error*
2005	710,325,427	709,825,786	0.1%
2006	691,832,918	691,498,056	0.0%
2007	707,210,539	710,814,989	0.5%
2008	699,380,696	697,643,131	0.2%
2009	681,018,592	682,543,385	0.2%
		Mean Absolute Percentage Error	**0.2%**

Actual WSL kWh vs. Estimates, Newmarket

Year	*Actual kWh*	*Predicted kWh*	*Absolute % Error*
2005	663,731,920	662,798,135	0.1%
2006	646,819,299	646,364,659	0.1%
2007	661,404,037	664,164,896	0.4%
2008	653,329,528	651,471,313	0.3%
2009	634,694,929	637,526,063	0.4%
		Mean Absolute Percentage Error	**0.3%**

Actual WSL kWh vs. Estimates, Tay

Year	*Actual kWh*	*Predicted kWh*	*Absolute % Error*
2002	45,184,865	45,469,586	0.6%
2003	45,498,041	45,608,581	0.2%
2004	45,502,991	44,895,906	1.3%
2005	46,593,507	47,027,651	0.9%
2006	45,013,619	45,133,398	0.3%
2007	45,806,502	46,650,093	1.8%
2008	46,051,168	46,171,818	0.3%
2009	46,323,663	45,017,322	2.8%
		Mean Absolute Percentage Error	***1.0%***

2.1 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells “average” out. While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. The OEB has considered and approved several different approaches to what constitutes "weather normal" over the past several years. For gas utilities, the Board has approved a five-year moving average for NRG (RP-2004-0167), a weighted average of 20 year and 30 year for Union Gas (RP-2003-0063), and a combination of methods including a 20 year trend, weighted average 20 year and 30 year, and variations of the so-called "de Bever" method depending upon location for Enbridge Gas Distribution (EB-2006-0034). For electric LDCs, Hydro One Networks Inc. (HONI) has used a 31 year average for their definition of weather normal (EB-2005-0378 and EB-2007-0681).

On the other hand, Toronto Hydro Electric System Limited (THESL) has used the most recent 10 year average as a definition of weather normal (EB-2005-0421 and EB-2007-0680) as have many of the LDCs that filed for cost-of-service rebasing for 2009 rates. We have adopted the 10 year average from 1999 to 2008 as the definition of weather normal for NTPDL's weather correction analysis. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing. For both Newmarket and Tay, we are using weather data from Pearson International Airport. The weather data is presented in the table below.

Table 3 –10-yr average (1999-2008) HDD and CDD, Pearson Int'l Airport

Heating Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1999	749.8	548.1	550.6	296.7	97.1	25.0	0.0	8.4	49.3	267.6	367.5	579.3	3539.4
2000	738.9	612.7	418.6	339.2	139.6	34.5	6.6	11.5	99.5	212.7	432.0	780.3	3,826.1
2001	684.9	587.6	566.6	293.8	111.5	29.8	9.3	0.0	73.6	232.5	325.8	505.0	3,420.4
2002	572.2	540.2	545.6	329.5	227.5	36.2	0.0	0.2	21.8	292.2	445.0	619.4	3,629.8
2003	814.5	699.0	581.1	372.5	177.9	43.4	0.2	2.0	54.9	276.0	398.5	561.5	3,981.5
2004	849.1	631.7	487.3	331.5	158.9	44.2	3.6	12.8	30.0	226.3	379.1	643.4	3,797.9
2005	770.0	616.4	608.6	306.8	189.4	8.9	0.0	0.2	22.6	220.2	388.4	665.3	3,796.8
2006	551.8	604.3	516.6	293.3	136.9	19.5	0.0	4.2	80.9	288.3	382.2	500.5	3,378.5
2007	647.1	740.1	546.7	356.4	136.4	16.5	3.2	5.2	36.9	137.7	462.5	630.7	3,719.4
2008	623.5	674.7	610.2	253.9	193.5	22.7	1.0	12.7	59.0	278.6	451.6	654.6	3,836.0
10-yr avg	***700.2***	***625.5***	***543.2***	***317.4***	***156.9***	***28.1***	***2.4***	***5.7***	***52.9***	***243.2***	***403.3***	***614.0***	***3692.6***

Cooling Degree Days

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1999	0.0	0.0	0.0	0.0	19.4	96.0	196.5	79.1	48.9	0.0	0.0	0.0	439.9
2000	0.0	0.0	0.0	0.0	23.7	41.1	71.8	92.5	35.2	1.2	0.0	0.0	265.5
2001	0.0	0.0	0.0	1.4	12.2	79.7	100.9	160.0	35.7	2.0	0.0	0.0	391.9
2002	0.0	0.0	0.0	8.3	7.8	70.0	192.4	142.7	87.6	10.0	0.0	0.0	518.8
2003	0.0	0.0	0.0	2.4	0.0	52.9	118.3	128.0	24.0	0.0	0.0	0.0	325.6
2004	0.0	0.0	0.0	0.0	8.6	31.6	86.4	59.6	41.2	1.5	0.0	0.0	228.9
2005	0.0	0.0	0.0	0.0	0.8	146.3	188.7	140.7	52.1	7.6	0.0	0.0	536.2
2006	0.0	0.0	0.0	0.0	26.0	73.6	167.3	101.6	12.9	1.1	0.0	0.0	382.5
2007	0.0	0.0	0.0	0.0	22.4	99.2	106.1	141.0	47.5	19.8	0.0	0.0	436
2008	0.0	0.0	0.0	0.0	2.5	71.5	111.0	64.0	26.7	0.0	0.0	0.0	275.7
10-yr avg	***0.0***	***0.0***	***0.0***	***1.2***	***12.3***	***76.2***	***133.9***	***110.9***	***41.2***	***4.3***	***0.0***	***0.0***	***380.1***

Forecasts for Ontario's employment outlook for 2010[2] are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 4 - Employment Forecast – Ontario
(figures in annual percentage change)

	BMO *(March 19,2010)*	RBC *(Mar 2010)*	Scotia *(Dec 23, 2009)*	TD *(Nov 3,2009)*	Avg
2010	1.1	1.3	0.7	0.8	1.0

Incorporating the forecast economic variables, calendar variables, and 10-yr weather normal heating and cooling degree days, the following weather corrected WSL consumption and forecast values are calculated:

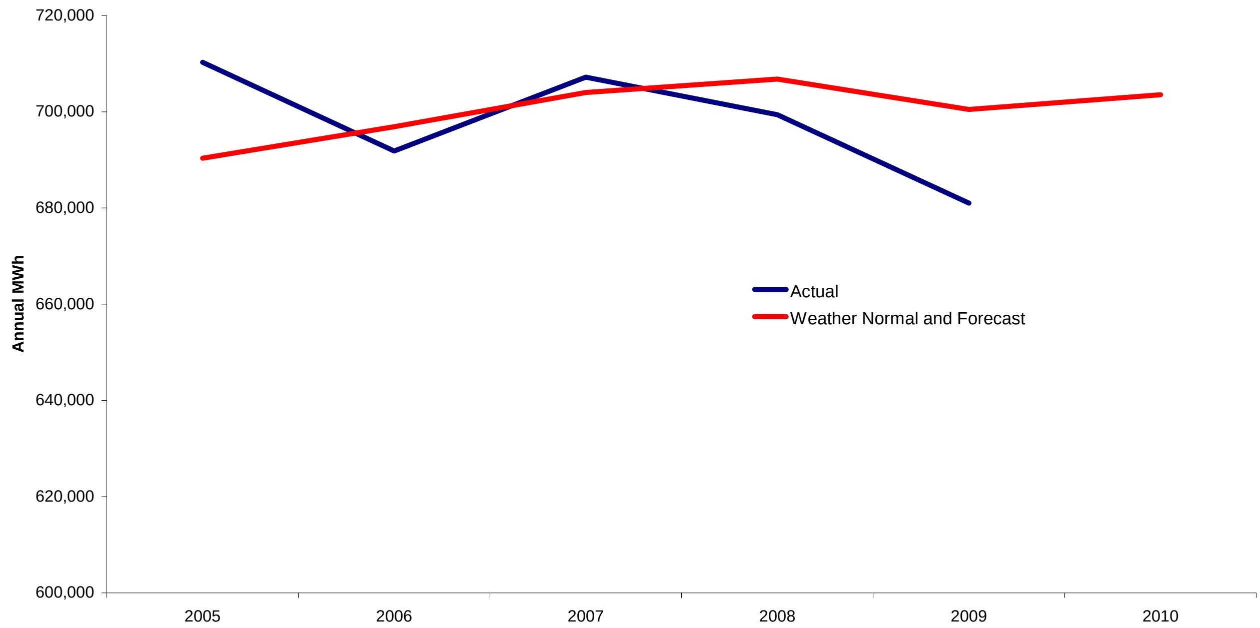
Table 5 - Weather Corrected Wholesale kWh, NTPDL[3]

Year	Actual WSL kWh	%chg	10-yr (1999-2008) Weather Normal	%chg
2005	710,325,427		690,344,726	
2006	691,832,918	*-2.6%*	696,897,633	*0.9%*
2007	707,210,539	*2.2%*	704,028,335	*1.0%*
2008	699,380,696	*-1.1%*	706,824,549	*0.4%*
2009	681,018,592	*-2.6%*	700,500,002	*-0.9%*
2010F			703,544,242	*0.4%*

Chart 3 below displays actual annual WSL (weather sensitive load) and weather normalized historic and forecast for NTPDL (Newmarket and Tay combined).

[2] 2009 actual values are now available.
[3] Separate values for Newmarket and Tay are displayed in Appendix A.

Chart 3
Newmarket-Tay WSL Actual vs. Weather Normal



2.2 Allocation to Specific Classes

Allocation of forecast and normalized WSL kWh to specific weather sensitive classes is based on each class' share in WSL kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2009. This allocation is done for each of Newmarket and Tay. Each of Newmarket and Tay are calculated separately and aggregated to derive the NTPDL class weather normal and forecast values.

As discussed in Section 1 of this report, four large GS>50 kW class customers in Newmarket have been removed from the GS>50 kW class. These customers are interval metered and are manufacturing customers. For Newmarket, the GS>50 share of WSL consumption is allocated based on the share excluding these customers. These customers' consumption is then added back to the GS>50 class consumption.

NTPDL CLASS FORECAST

Table 6 presents class specific weather normal historic and forecast values for classes that have weather sensitive load for NTPDL (Newmarket and Tay are set out separately in Appendix A).

Table 6 - Weather Corrected Class Specific Consumption, NTPDL

			10-yr (1999-2008)	
Year	Actual residential kWh	*% chg*	Weather Normal	*% chg*
2005	274,444,669		266,878,766	
2006	263,869,589	*-3.9%*	266,016,444	*-0.3%*
2007	270,095,098	*2.4%*	269,084,727	*1.2%*
2008	267,843,118	*-0.8%*	270,664,124	*0.6%*
2009	266,653,971	*-0.4%*	273,677,264	*1.1%*
2010F			274,854,374	*0.4%*
Year	Actual GS<50 kWh	*% chg*	Weather Normal	*% chg*
2005	103,290,917		100,372,653	
2006	93,336,349	*-9.6%*	94,000,475	*-6.3%*
2007	97,653,639	*4.6%*	97,191,291	*3.4%*
2008	96,233,341	*-1.5%*	97,259,917	*0.1%*
2009	92,641,999	*-3.7%*	95,338,741	*-2.0%*
2010F			95,754,008	*0.4%*
Year	Actual GS>50 kWh	*% chg*	Weather Normal	*% chg*
2005	356,001,595		347,510,614	
2006	357,391,830	*0.4%*	359,356,526	*3.4%*
2007	363,995,957	*1.8%*	362,378,335	*0.8%*
2008	365,072,211	*0.3%*	368,466,063	*1.7%*
2009	316,486,393	*-13.3%*	325,592,529	*-11.6%*
2010F			313,112,561	*-3.8%*

Actual, normalized and forecast kW for the weather sensitive GS>50 class for NTPDL are summarized in Table 7 below. Historical normalized values are calculated based on the annual ratio of class kW to class kWh for the individual Newmarket and Tay forecasts. Forecast kW is based on the average of the class kW to class kWh ratio in 2009 (individually for Newmarket and Tay).

Table 7 – GS>50 Class kW (Actual, Normalized, and Forecast), NTPDL

Year	Actual kW	% chg	Normalized kW	% chg
2005	848,883		828,643	
2006	875,147	3.1%	879,979	6.2%
2007	874,499	-0.1%	870,600	-1.1%
2008	868,549	-0.7%	876,623	0.7%
2009	796,992	-8.2%	819,940	-6.5%
2010F			788,494	-3.8%

NON-WEATHER SENSITIVE CLASSES AND CUSTOMER CONNECTION FORECAST

Table 8 below presents actual and forecast kWh and kW (where applicable) for the non-weather sensitive classes - Street Lighting, Sentinel Lighting and Unmetered Scattered Load (USL).

Forecast throughput for Street Lighting, Sentinel Lighting and USL is based on the most recent actual use per customer (2009) and the forecast change in customers for these classes. The forecast for the number of customers in the residential class and street lighting are informed by housing starts reported by CMHC (Canada Mortgage and Housing Corp) for Newmarket and also from information from the utility. Based on data reported by CMHC, Newmarket unlike some parts of the GTA and the Province, continued seeing a significant increase in the number of housing starts and completions. However, while the number of units is increasing, the size of the units are smaller than what has been built historically.

Table 8

Non-Weather Sensitive Historic and Forecast Consumption – NTPDL

	Street Lighting				*Sentinel Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2005	4,718,748		13,151		323,151		1,030	
2006	4,868,337	3.2%	13,465	2.4%	319,689	-1.1%	1,030	0.0%
2007	4,944,311	1.6%	13,652	1.4%	319,360	-0.1%	969	-5.9%
2008	5,167,674	4.5%	14,040	2.8%	318,972	-0.1%	969	0.0%
2009	5,286,191	2.3%	14,393	2.5%	314,839	-1.3%	874	-9.8%
2010F	5,355,339	1.3%	14,581	1.3%	306,233	-2.7%	850	-2.7%

USL (Unmetered Scattered Load)

Year	kWh	%
2005	441,440	
2006	425,229	-3.7%
2007	360,984	-15.1%
2008	397,591	10.1%
2009	391,118	-1.6%
2010F	391,118	0.0%

The historical average annual customer connections and 2010 forecasts are displayed in Table 9 below.

Table 9 – Average Annual Customer Connections – NTPDL

	2005	2006	2007	2008	2009	2010F
Residential	26,545	27,229	27,595	28,147	28,852	29,370
% chg		*2.6%*	*1.3%*	*2.0%*	*2.5%*	*1.8%*
GS<50 kW	2,776	2,775	2,791	2,843	2,881	2,901
% chg		*0.0%*	*0.6%*	*1.9%*	*1.3%*	*0.7%*
GS> 50 kW	349	375	385	395	398	401
% chg		*7.4%*	*2.8%*	*2.7%*	*0.6%*	*0.8%*
Street Light	7,674	7,889	8,029	8,208	8,463	8,574
% chg		*2.8%*	*1.8%*	*2.2%*	*3.1%*	*1.3%*
Sentinel Light	444	444	444	444	426	414
USL	140	132	129	125	125	125
% chg		*-5.8%*	*-2.3%*	*-3.0%*	*-0.1%*	*0.1%*

SUMMARY

Table 10 presents the results for class specific historic actual and historic normalized kWh and kW (where applicable) for 2008, normalized 2009 and normalized forecast values for 2010.

Table 10 – NTPDL Load Forecast Summary.

	2008 Actual	2008 Normalized	2009 Normalized	2010f Normalized
Residential (kWh)	267,843,118	270,664,124	273,677,264	274,854,374
GS<50 (kWh)	96,233,341	97,259,917	95,338,741	95,754,008
GS>50 (kWh)	365,072,211	368,466,063	325,592,529	313,112,561
(kW)	868,549	876,623	819,940	788,494
Street Lights (kWh)	5,167,674	5,167,674	5,286,191	5,355,339
(kW)	14,040	14,040	14,393	14,581
Sentinel Lights (kWh)	318,972	318,972	314,839	306,233
(kW)	969	969	874	850
USL (kWh)	397,591	397,591	391,118	391,118
Total Retail kWh	735,032,907	742,274,340	700,600,681	689,773,632

Average Use

Weather actual and weather normal average use is displayed in the following table.

Table 11 - Weather Actual Use Per Customer – NTPDL

Year	Residential	GS<50	GS>50	Street	Sentinel	USL
2005	10,339	37,204	1,020,793	615	728	3,153
2006	9,691	33,635	954,105	617	720	3,223
2007	9,788	34,991	945,649	616	719	2,800
2008	9,516	33,847	923,260	630	718	3,181
2009	9,242	32,160	795,858	625	740	3,131

Weather Normal Use Per Customer – NTPDL

Year	Residential	GS<50	GS>50
2005	10,054	36,153	996,446
2006	9,770	33,874	959,350
2007	9,751	34,825	941,446
2008	9,616	34,208	931,843
2009	9,485	33,096	818,757
2010	9,358	33,012	780,829

APPENDIX A

Weather Corrected WSL kWh, Newmarket				
			10-yr (1999-2008)	
Year	Actual kWh	%chg	Weather Normal	%chg
2005	663,731,920		644,655,376	
2006	646,819,299	-2.5%	650,880,714	1.0%
2007	661,404,037	2.3%	657,827,417	1.1%
2008	653,329,528	-1.2%	660,368,043	0.4%
2009	634,694,929	-2.9%	654,679,174	-0.9%
2010F			657,561,285	0.4%

Weather Corrected WSL kWh, Tay				
			10-yr (1999-2008)	
Year	Actual kWh	%chg	Weather Normal	%chg
2002	45,184,865		44,725,469	
2003	45,498,041	0.7%	45,144,167	0.9%
2004	45,502,991	0.0%	45,601,457	1.0%
2005	46,593,507	2.4%	45,689,349	0.2%
2006	45,013,619	-3.4%	46,016,919	0.7%
2007	45,806,502	1.8%	46,200,918	0.4%
2008	46,051,168	0.5%	46,456,506	0.6%
2009	46,323,663	0.6%	45,820,828	-1.4%
2010F			45,982,957	0.4%

Weather Corrected Class Specific Consumption, Newmarket			
			10-yr (1999-2008)
Year	Actual residential kWh	Share%	Weather Normal
2005	239,954,381	0.361523	233,057,771
2006	233,263,087	0.360631	234,727,759
2007	237,979,456	0.359809	236,692,554
2008	235,100,343	0.35985	237,633,149
2009	234,234,587	0.369051	241,609,786
2010F			242,673,431
Year	Actual GS<50 kWh	Share%	Weather Normal
2005	97,886,589	0.147479	95,073,198
2006	88,460,500	0.136762	89,015,948
2007	92,965,057	0.140557	92,462,338
2008	91,072,181	0.139397	92,053,329
2009	87,440,920	0.137768	90,194,118
2010F			90,591,182

Year	Actual GS>50 kWh	*Share%*	Weather Normal
2005	351,777,009	[redacted]	343,368,007
2006	352,920,959		354,786,004
2007	358,534,989		356,870,346
2008	359,489,461		362,834,174
2009	310,871,029		320,038,119
2010F			307,538,497

Weather Corrected Class Specific Consumption, Tay			
			10-yr (1999-2008)
Year	Actual residential kWh	*Share%*	Weather Normal
2002	31,056,118	0.68731	30,740,370
2003	31,844,015	0.69990	31,596,340
2004	31,536,736	0.69307	31,604,980
2005	34,490,287	0.74024	33,820,995
2006	30,606,503	0.67994	31,288,685
2007	32,115,642	0.70112	32,392,173
2008	32,742,776	0.71101	33,030,974
2009	32,419,384	0.69985	32,067,477
2010F			32,180,943
Year	Actual GS<50 kWh	*Share%*	Weather Normal
2002	5,956,059	0.13182	5,895,503
2003	5,330,605	0.11716	5,289,145
2004	4,948,766	0.10876	4,959,475
2005	5,404,328	0.11599	5,299,456
2006	4,875,849	0.10832	4,984,526
2007	4,688,582	0.10236	4,728,953
2008	5,161,160	0.11207	5,206,588
2009	5,201,079	0.11228	5,144,623
2010F			5,162,826
Year	Actual GS>50 kWh	*Share%*	Weather Normal
2002	4,474,923	0.09904	4,429,426
2003	4,512,606	0.09918	4,477,508
2004	4,299,431	0.09449	4,308,735
2005	4,224,586	0.09067	4,142,607
2006	4,470,871	0.09932	4,570,522
2007	5,460,967	0.11922	5,507,989
2008	5,582,750	0.12123	5,631,889
2009	5,615,364	0.12122	5,554,410
2010F			5,574,063

Newmarket	2008 Actual	2008 Normalized	2009 Normalized	2010f Normalized
Residential (kWh)	235,100,343	237,633,149	241,609,786	242,673,431
GS<50 (kWh)	91,072,181	92,053,329	90,194,118	90,591,182
GS>50 (kWh)	359,489,461	362,834,174	320,038,119	307,538,497
(kW)	854,429	862,379	806,353	774,860
Street Lights (kWh)	4,721,265	4,721,265	4,848,000	4,917,148
(kW)	12,818	12,818	13,172	13,360
Sentinel Lights (kWh)	308,910	308,910	305,789	297,183
(kW)	945	945	850	826
USL (kWh)	212,128	212,128	211,968	211,968
Total Retail kWh	690,904,288	697,762,955	657,207,780	646,229,409

Tay	2008 Actual	2008 Normalized	2009 Normalized	2010f Normalized
Residential (kWh)	32,742,776	33,030,974	32,067,477	32,180,943
GS<50 (kWh)	5,161,160	5,206,588	5,144,623	5,162,826
GS>50 (kWh)	5,582,750	5,631,889	5,554,410	5,574,063
(kW)	14,120	14,244	13,587	13,635
Street Lights (kWh)	446,409	446,409	438,191	438,191
(kW)	1,222	1,222	1,222	1,222
Sentinel Lights (kWh)	10,062	10,062	9,050	9,050
(kW)	24	24	24	24
USL (kWh)	185,463	185,463	179,150	179,150
Total Retail kWh	44,128,619	44,511,385	43,392,901	43,544,223

Newmarket Customers	2005	2006	2007	2008	2009	2010F
Residential	22,863	23,495	23,815	24,339	25,030	25,530
% chg		*2.8%*	*1.4%*	*2.2%*	*2.8%*	*2.0%*
GS<50 kW	2,561	2,563	2,577	2,626	2,660	2,676
% chg		*0.1%*	*0.6%*	*1.9%*	*1.3%*	*0.6%*
GS> 50 kW	338	363	370	378	382	385
% chg		*7.6%*	*1.8%*	*2.3%*	*0.8%*	*0.9%*
Street Light	6,967	7,178	7,318	7,497	7,751	7,862
% chg		*3.0%*	*2.0%*	*2.4%*	*3.4%*	*1.4%*
Sentinel Light	430	430	430	430	412	400
USL	75	75	75	75	75	75
% chg		*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*

Tay Customers	2005	2006	2007	2008	2009	2010F
Residential	3,681	3,734	3,780	3,808	3,822	3,840
% chg		*1.4%*	*1.2%*	*0.7%*	*0.4%*	*0.5%*
GS<50 kW	215	212	214	217	221	225
% chg		*-1.5%*	*0.7%*	*1.6%*	*1.7%*	*1.8%*
GS> 50 kW	11	11	15	17	16	16
% chg		*2.3%*	*33.3%*	*13.3%*	*-4.9%*	*-1.0%*
Street Light	707	712	711	711	712	712
% chg		*0.7%*	*-0.1%*	*0.0%*	*0.1%*	*0.0%*
Sentinel Light	14	14	14	14	14	14
USL	65	57	54	50	50	50
% chg		*-12.4%*	*-5.3%*	*-7.3%*	*-0.2%*	*0.2%*

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The Effects of Time-of-Use Rates on Residential Electricity Consumption

Presented to

Newmarket Tay Power Distribution

April 9, 2010

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EXECUTIVE SUMMARY

Newmarket Tay Power Distribution retained Navigant Consulting Inc. (Navigant Consulting) to estimate the effect that switching from the Ontario Energy Board's (OEB) Regulated Price Plan (RPP) tiered price structure to the time-of-use (TOU) price structure had on the consumption of electricity by a group of Newmarket Tay Power Distribution's (NTP) residential customers and explore the opportunities presented to NTP for improving that response.

The three principal objectives of this study were to:

1. Estimate the degree to which the introduction of TOU rates had encouraged residential consumers to shift their consumption away from the on-peak period.
2. Estimate the degree to which the introduction of TOU rates had encouraged residential consumers to reduce their consumption of all electricity – the conservation effect.
3. Use survey data obtained from NTP customers whose consumption data had been used to achieve the first two objectives to identify opportunities for improving residential TOU response; shifting away from on-peak and mid-peak periods toward off-peak periods.

Data Used

NTP provided NCI with hourly consumption data from four groups (cycles) of residential customers all from within its Newmarket service area; one control group, which was switched to TOU rates only after the period of analysis, and three experimental groups, all of which were switched from tiered RPP rates to TOU RPP rates at some time during the period of analysis.

This data-set is the largest (in terms of accounts) and the longest (in terms of period of analysis) yet used in Ontario for an assessment of TOU rate impacts. In total the hourly electricity consumption data from more than three thousand different customers was used in a period of analysis of over eight hundred days.

Survey data was provided by a third-party market research firm, Northstar Research Partners, that obtained responses to a detailed telephone survey from 10% of those customers in the original sample.

Method

The demand response impact of the introduction of TOU rates and the conservation effect engendered by such rates were estimated using an econometric technique known as "fixed effects". This technique has already been fruitfully employed by two other major studies of the impact of TOU rates in Ontario.

Although previous Ontario TOU studies have used two-way fixed effects Navigant Consulting determined that in this case – principally because of possibilities afforded by a much longer time-wise data-set than has heretofore been available – using only individual fixed effects and explicitly controlling for time-variant drivers of electricity consumption would provide more accurate estimates of both the demand response impact and conservation effect of TOU prices.

To allow for more direct comparability across studies, Navigant Consulting has also estimated the demand response impact and conservation effect using two-way fixed effects. Caution should be exercised in assessing these estimates as Navigant Consulting is confident that the estimates generated by the individual fixed effects models provide a more accurate estimate of the impact of TOU prices.

Navigant Consulting used the survey data to segment the main sample to explore to what degree those surveyed were representative of the larger sample (in terms of shifting and conservation) and to what degree the best informed customers' (BICs) shifting and conservation differed from that of the rest of those surveyed, and the sample as a whole.

The survey data was also explored for correlations which could suggest opportunities for NTP and others to improve overall customer response to TOU rates.

Conclusions

Navigant Consulting observed a statistically significant demand response impact from TOU rates. On average, Newmarket households in the sample studied which became subject to TOU prices reduced both on-peak and mid-peak electricity consumption and increased off-peak weekend consumption but not off-peak weekday consumption.

As discussed above Navigant Consulting used two different econometric models to estimate the impact of TOU rates on energy conservation – individual fixed effects only and two-way fixed effects. In *neither* model did Navigant Consulting observe any statistically significant conservation impact due to the introduction of TOU rates.

The estimated demand response impacts and conservation effect are summarised in Table 1 below. Parameter estimates should be interpreted as the percentage impact which TOU prices have had on consumption in the period in question. For example: TOU rates are estimated to have reduced on-peak consumption by 2.8% and increased off-peak weekend consumption by 2.21%.

Red cells indicate parameter estimates that are not statistically significantly different from zero when tested at a 95% confidence level.

Table 1 - Overall Demand Response Impact and Conservation Effect

	Parameter Estimate
On-peak	-2.80%
Mid-peak	-1.39%
Off-peak Weekdays	0.16%
Off-peak Weekends	2.21%
Conservation effect	0.66%

Re-estimating the fixed-effects models using only the control group and the accounts of customers who responded to the survey, it was observed that survey respondents had, on average, a greater response to TOU rates than did the rest of the sample. This suggests that the survey sample data is slightly contaminated by self-selection bias.

This is not surprising. On average, holding other things equal, customers willing to spend twenty minutes on the telephone for a study offering them no pecuniary incentive will tend to be those more positively disposed toward the subject of the survey than most. It also follows that, generally, individuals that are reasonably well-disposed to TOU pricing will also be likely to pursue shifting or conservation actions with more alacrity than average.

This self-selection bias should be borne in mind when examining the results of the survey presented below, and the reader should be take care when comparing these results to those of other studies to note what, if any, self-selection bias may also be present in those studies.

In exploring opportunities for NTP to improve customer response to TOU rates, Navigant Consulting re-estimated the fixed-effects models using only the control group and the accounts of customers included in the survey whom Navigant Consulting could identify as BICs. The result of this analysis was unequivocal – BICs response to on-peak and mid-peak TOU periods was more than ten percentage points greater than that of the entire sample. Navigant Consulting has explored some of the other characteristics of these customers with some suggestive, but not (due to the small sample size) conclusive results, and has provided some suggestions as to how NTP can leverage these customers' enthusiasm to improve TOU response in its wider customer base.

Overall, Navigant Consulting's findings may be summarised in the following manner:

- TOU rates are accomplishing what they have been designed to do. Although average changes in consumption during the on-peak and mid-peak periods may appear small, they are significant and correspond directionally to what the rate design intends.
- What public concern there is regarding increased electricity costs under TOU rates fades rapidly as customers adapt to the new rate design and perceive that TOU rates have a neutral or slightly favourable impact on their electricity bill.

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INTRODUCTION

Newmarket Tay Power Distribution retained Navigant Consulting Inc. (Navigant Consulting) to estimate the effect that switching from the Ontario Energy Board's (OEB) Regulated Price Plan (RPP) tiered price structure to the time-of-use (TOU) price structure had on the consumption of electricity by a group of Newmarket Tay Power Distribution's (NTP) residential customers and explore the opportunities presented to NTP for improving that response.

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3. Use survey data obtained from NTP customers whose consumption data had been used to achieve the first two objectives to identify opportunities for improving residential TOU response; shifting away from on-peak and mid-peak periods toward off-peak periods.

Econometric Analysis

The macro effect of TOU prices on the electricity consumption of the three experimental groups ("cycles") for which NTP provided data was estimated using an econometric estimation technique known as "fixed effects". This technique for analysing panel (also known as longitudinal) data allows the analyst to control for unobserved heterogeneity between different individuals and, if two fixed effects are used, between different time periods. This method has been used twice before in Ontario for estimating the effect that TOU prices have had on residential electricity consumption. For context, the results of both the *Ontario Energy Board Smart Price Pilot* and the *Hydro One Networks Time-of-Use Pilot Project*, as well as brief description of the methods and data for these studies are presented below.

It should be noted that the results presented below must be regarded as point estimates of behaviour that has occurred (and is likely evolving), and caution should be exercised in extrapolating these results to other jurisdictions or to the future. Without truly dynamic prices (which change frequently throughout the day in response to changes in the wholesale price of electricity) communicated to consumers in real time (or with a relatively short lag) it is virtually impossible to estimate a consumer demand function for electricity.

Without a consumer demand function, and given the fact that the price of all the available "goods" (on-peak, mid-peak and off-peak consumption) change simultaneously, it is impossible to decompose to what degree the change in consumption of one good (e.g. on-peak electricity) is due to the change in its own price and to what degree the change in consumption of that good is due to the change in price of its substitutes (mid-peak and off-peak electricity).

The up-shot of this is that it is not possible (without a consumer demand function) to estimate the *relationship* between, for example, on-peak demand and the on-peak price (the own-price elasticity of demand for on-peak electricity). Only the *reaction* of consumers (in terms of their on-peak consumption) to an overall change in the menu of electricity prices may be estimated.

In summary, the results presented below must be understood to be an assessment of the effect that switching from RPP to TOU prices has had on the residential consumption of electricity in various TOU time-periods. The results presented below should not be thought of as a forecast of the effect a change in the price of electricity in one TOU period will have on the residential consumption of electricity in that same period.

Survey Analysis

In addition to the econometric analysis of NTP customer consumption data, a third-party market research firm, Northstar Research Partners, was engaged to survey customers whose data had been used in the econometric analysis.

Altogether survey responses were obtained from 10% of the customers whose data was used in estimating the fixed-effects models, distributed evenly across the three experimental and the single control cycle.

This data was used in several different ways. Firstly it enabled Navigant Consulting to isolate the best informed customers (BICs) – those that could perfectly identify the beginning and ending of all the on-peak periods, winter and summer – and re-estimate the fixed effect. This has enabled Navigant Consulting to quantify the degree to which BICs out-perform the average in terms of consumption reductions during the on-peak and mid-peak periods. Data from the survey further allowed Navigant Consulting to attempt to identify the salient characteristics of these customers which might allow NTP to improve general customer response to TOU rates.

Additionally, the survey data allowed Navigant Consulting to explore the attitudes that NTP customers have about TOU rates, and, in particular, how these attitudes change over time for the better.

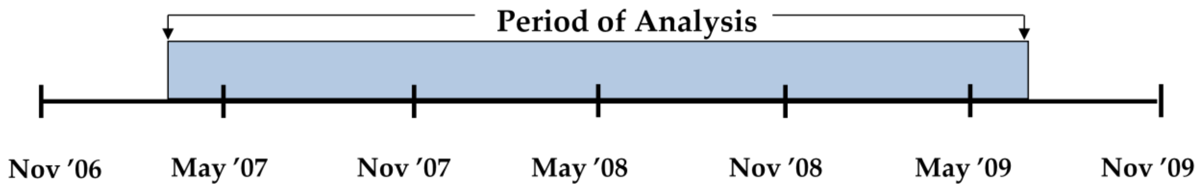
Standard and TOU Rate Structure

Under amendments to the Ontario Energy Board Act, 1998 (the Act) contained in the Electricity Restructuring Act, 2004, the Ontario Energy Board was mandated to develop a Regulated Price Plan (RPP) for electricity prices to be charged to consumers that have been designated by regulation. The first prices were implemented under the RPP effective on April 1, 2005, as set out in regulation by the Ontario Government.

The principles that have guided the Ontario Energy Board in developing the RPP were established by the Ontario Government. In accordance with legislation, the prices paid for electricity by RPP consumers are based on forecasts of the cost of supplying them and must be set to recover those forecast costs. RPP prices are currently reviewed and adjusted if necessary by the OEB every six months.

During the period of analysis for this study (April 1, 2007 to July 12, 2009), control group customers were exposed to five separate sets of tiered electricity prices and experimental group customers were exposed to three separate sets of tiered electricity prices before they switched over to TOU rates. The OEB reset tiered prices on November 1st, 2006, 2007, 2008 and May 1st, 2007, 2008, 2009. Figure 1 illustrates the different RPP periods experienced by the control group and the experimental groups during the period of analysis.

Figure 1 - RPP Price Resetting During the Period of Analysis



Standard Regulated Price Plan Prices

The conventional meter RPP has a two-tiered pricing structure, one price for monthly consumption under a tier threshold and a higher price for consumption over the tier threshold. From November 1, 2005, the tier threshold for residential consumers has changed twice a year on a seasonal basis: to 600 kWh per month during the summer season (May 1 to October 31) and to 1000 kWh per month during the winter season (November 1 to April 30).

Subsequent to April 2006, the RPP prices were reviewed by the Board every six months and adjusted, if necessary. The RPP prices in effect during this study reflect this resetting frequency and are shown in Table 2.

Table 2 - Conventional RPP Prices During the Period of Analysis

Cents per kWh	Nov '06 - April '07	May '07 - Oct '07	Nov '07 - April '08	May '08 - Oct '08	Nov '08 - April '09	May '09 - Nov '09
Tier 1	5.5	5.3	5	5	5.6	5.7
Tier 2	6.4	6.2	5.9	5.9	6.5	6.6

TOU Regulated Price Plan Prices

Consumers with eligible time-of-use (or "smart") meters that can measure and record electricity consumption for hourly (or shorter) intervals will pay under a time-of-use (TOU) price structure. The prices under this plan are based on three time-of-use periods. These periods are referred to as Off-Peak, Mid-Peak and On-Peak. The lowest (Off-Peak) price is below the tier prices, while the other two are above them. The three prices are related to each other in approximately a 1:2:3 ratio.

The RPP TOU prices are also reviewed and adjusted if necessary every six months. Table 3 below outlines the TOU prices in effect during the period of analysis.

Table 3 - RPP TOU Prices During the Period of Analysis

Cents per kWh	Nov '06 - April '07	May '07 - Oct '07	Nov '07 - April '08	May '08 - Oct '08	Nov '08 - April '09	May '09 - Nov '09
On-peak	9.7	9.2	8.7	9.3	8.8	9.1
Mid-peak	7.1	7.2	7	7.3	7.2	7.6
Off-peak	3.4	3.2	3	2.7	4	4.2

The hours of these three TOU periods are set out in Table 4 below. It should be noted that on occasion within this report comparisons are made between the consumption during on-peak weekday hours, and during the same hours of the day on weekends. References to, for example, the consumption during the on-peak hours of the weekend should be understood by the reader to be convenient short-hand for comparing the same hours of the day, and not that there is some part of weekend electricity consumption that is subject to on-peak TOU prices.

Table 4 – RPP TOU Hours in Summer and Winter

Time	Summer Period (May 1 – Oct 31)	Winter Period (Nov 1 – April 30)
Off-Peak	10pm – 7am* weekdays and all day on weekends and holidays	10pm – 7am* weekdays and all day on weekends and holidays
Mid-Peak	7am – 11am and 5pm – 10pm* weekdays	11am – 5pm and 8pm – 10pm* weekdays
On-Peak	11am – 5pm weekdays	7am – 11am and 5pm – 8pm* weekdays

* Note that in the time since the end of the period of analysis the TOU periods have changed. The periods above, however correspond with those to which customers in the sample would have been subject to over the period of analysis.

Figure 2 graphically displays the summer TOU prices based on the May 2008 – October 2008 price setting, while Figure 3 shows winter TOU prices based on the Board's price setting effective November 2008 through April 2009.

Figure 2 - Summer RPP TOU Prices, May 2008 - October 2008

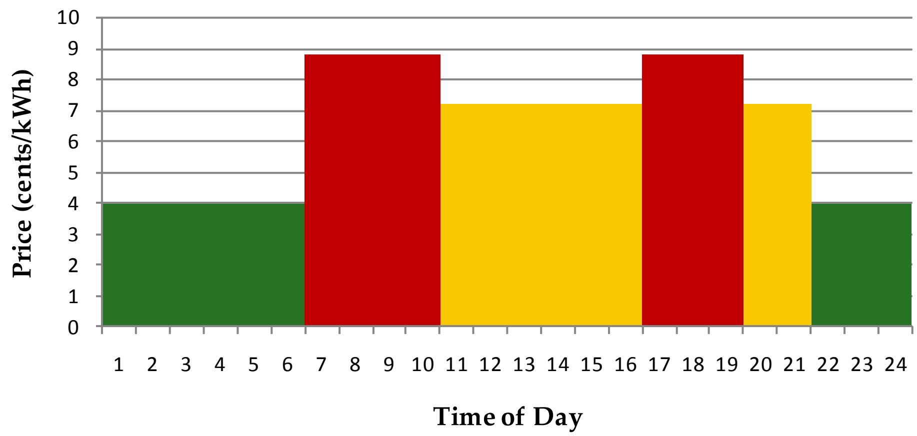
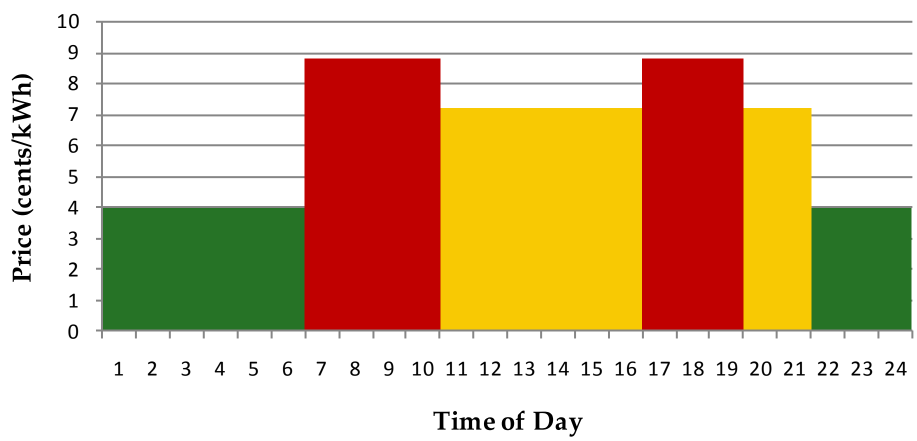


Figure 3 - Winter RPP TOU Prices, November 2008 - April 2009



DATA USED – ECONOMETRIC ANALYSIS

NTP provided Navigant Consulting with hourly consumption data from four groups (cycles) of residential customers; one control group, which has not yet been switched to TOU rates, and three experimental groups all of which were switched from tiered RPP rates to TOU RPP rates at some time during the period of analysis.

It was necessary to drop some individuals from within each group due to a number of factors that rendered them unsuitable for the analysis. For example: individual accounts were dropped when the time series for that account began less than six months before that account was switched over to TOU rates.

After all unsuitable accounts were dropped the data which remained, and from which the results presented in this report, are summarized in Table 5 below.

Table 5 - Household Account Data Used in Analysis

	Cycle 26	Cycle 27	Cycle 28	Cycle 29
Number of Accounts	883	690	840	762
Date of switch to TOU	Never - Control Group	1-Dec-07	1-Apr-08	1-May-08
Date of earliest data point	5-Apr-07	4-Apr-07	1-Apr-07	1-Apr-07
Date of latest data point	12-Jul-09	12-Jul-09	12-Jul-09	12-Jul-09
Period of analysis: 833 days				

Data For Shifting Analysis

Each account's hourly time series was then aggregated into three parallel daily time series: daily consumption during the on-peak, off-peak and mid-peak hours for every day of the week, including weekends and holidays, when only the off-peak rate applies. This aggregation took into account the effect of daylight savings time and the manner in which the TOU periods shift from winter to summer. Greater detail of how this data was used for the estimation may be found in Appendix A – Model Details.

Data For Conservation Effect Analysis

For studying the conservation effect, the hourly data was, for each account, aggregated even further to provide a weekly series of consumption quantities for each account.

Data From Previous TOU Studies

For additional context the data used in both the OEBSPP and the Hydro One pilot are presented in Table 6 below. It should be noted that both studies had fewer participants (all of whom were self-selected) who were observed over a shorter period of time. It should also be noted that neither of these studies had access to consumption data for the experimental group(s) from any period preceding the introduction of TOU pricing.

Table 6 - Data Used in Similar Studies

	OEBSPP		Hydro One		
	Experimental	Control	TOU only	TOU with RTM	Control
Number of Accounts	124	125	177	153	75
Date of earliest data point	1-Aug-06		1-May-07		
Date of latest data point	28-Feb-07		1-Oct-07		
Period of analysis (days)	211		153		

Method and Models Used for Econometric Estimation

The demand response impact and conservation effect analysis were both estimated using an econometric panel data technique known as "fixed effects". The use of fixed effects allows the analyst to control for the individual characteristics of each household that are constant through time (e.g. square footage, type of furnace, etc.) without explicitly modeling the relationship between these characteristics and the variable of interest (electricity consumption). In essence, each individual household is assigned its own dummy variable.

It is also possible to use a second fixed effect – for the day of the sample – to control for the individual characteristics of each day that remain constant across individuals. As with individual level fixed effects, this is equivalent to assigning a dummy variable to each day of the sample. This is the technique employed by the two previous studies of the effect of TOU pricing in Ontario cited earlier.

In this case, however, it was felt that using only one-way (individual) fixed effects would allow for a more accurate estimate of the true effect of TOU prices. One of the disadvantages of including a fixed effect is that such an estimator is not consistent in the probability limit. Put another way, when using day-of-sample fixed effects our estimate of the time-dependent impacts on the dependent variable do not incrementally improve as observations accrue over time.

If we accept the assumption that the two principal drivers of daily electricity demand are the weather and whether or not a day is a holiday or weekend, and we further accept the assumption that, on average, residential consumers tend to adjust their consumption in a relatively consistent way to these drivers, then using individual fixed effects and explicitly controlling for both of these drivers by including them as independent variables will provide a more accurate estimate of their effect on consumption. This, in turn, will mean we will obtain a more accurate estimate of the effect of TOU prices on consumption. Using only an individual fixed effect and explicitly controlling for time-variant factors allows us to take advantage of the great length of the time series and the attendant accumulation of information in the data in a way that simply assigning a dummy variable to each individual time period does not.

To allow for consistency and comparability across studies, however, NCI has, in addition to a series of one-way fixed effects models, also used the data to estimate two-way fixed effects models of both the demand response impact and the conservation effect. The details of all the models used are presented in the attached Appendix.

For easy reference and to aid the reader in keeping track of the various models Table 7 and Table 8 below summarize the purpose of each model in the overall analysis.

Table 7 - Model Key - Individual Fixed Effects

Individual Fixed Effects	
Model	**Purpose**
A1	Estimate the demand response effect of TOU prices on consumption during weekday on-peak, mid-peak and off-peak hours for each experimental group.
A2	Estimate the demand response effect of TOU prices on consumption during weekend off-peak hours for each experimental group.
A3	Estimate the demand response effect of TOU prices on consumption during weekday on-peak, mid-peak and off-peak hours for the aggregated sample of all three experimental groups.
A4	Estimate the demand response effect of TOU prices on consumption during weekend off-peak hours for the aggregated sample of all three experimental groups.
B1	Estimate the conservation effect of TOU prices for each experimental group.
B2	Estimate the conservation effect of TOU prices for the aggregated sample of all three experimental groups.

Table 8 - Model Key - Two-way Fixed Effects

Two-way Fixed Effects	
Model	**Purpose**
C1	Estimate the demand response effect of TOU prices on consumption during weekday on-peak, mid-peak and off-peak hours for each experimental group.
C2	Estimate the demand response effect of TOU prices on consumption during weekend off-peak hours for each experimental group.
C3	Estimate the demand response effect of TOU prices on consumption during weekday on-peak, mid-peak and off-peak hours for the aggregated sample of all three experimental groups.
C4	Estimate the demand response effect of TOU prices on consumption during weekend off-peak hours for the aggregated sample of all three experimental groups.
D1	Estimate the conservation effect of TOU prices for each experimental group.
D2	Estimate the conservation effect of TOU prices for the aggregated sample of all three experimental groups.

Econometric Analysis

Overall Demand Response Impact and Conservation Effect – Individual Fixed Effects

The overall effect of TOU prices on all Newmarket households that became subject to such prices during the period of analysis appears to be that, on average, customers have reduced on-peak (-2.8%) and mid-peak (-1.39%) consumption and somewhat increased consumption on weekends and holidays (+2.21%). The estimate of the conservation effect of TOU prices on all Newmarket households that became subject to such prices during the period of analysis was found to not be statistically significantly different from zero. We cannot, at any conventional level of confidence, be sure that TOU rates affected overall electricity consumption in any way. Parameter estimates and standard errors are presented in Table 9 below.

Red cells indicate parameter estimates that are not statistically significantly different from zero when tested at a 95% confidence level.

All other parameter estimates for this model were statistically significant. It is worth noting that that the parameter estimates for the effect of holidays and weekends were quite large, relative to TOU effects. It appears that, on average, households consume 11.93% more electricity during the on-peak hours of weekends and holidays than they do on weekdays, and 8.56% more electricity during the mid-peak hours.

Table 9 - Overall Demand Response Impact and Conservation Effect - Individual Fixed Effects

	Parameter Estimate	Standard Error
On-peak	-2.80%	0.0046959
Mid-peak	-1.39%	0.0043356
Off-peak Weekdays	0.16%	0.0041979
Off-peak Weekends	2.21%	0.0038561
Conservation effect	0.66%	0.0043197

Group Specific Demand Response Impact and Conservation Effect – Individual Fixed Effects

Of the three experimental groups examined, households in Cycle 27 (on TOU rates from Dec. 1, 2007) proved to have the most consistent response to the introduction of TOU rates, reducing, on average, both on-peak (-4.31%) and mid-peak consumption (-5.42%) and increasing off-peak weekend consumption (+3.74%) . The fact that the estimate of the conservation effect for this cycle is not statistically significantly different from zero suggests that TOU rates in this case provoked only shifting, rather than conservation, behaviour. All parameter estimates and standard errors are presented in Table 10 below.

The results for Cycle 28 (on TOU rates from April 1, 2009) initially appear counter-intuitive; the introduction of TOU rates appears to have had the effect of, on average increasing off-peak weekend consumption (+1.88%) without any corresponding decrease in the consumption of either on-peak or mid-peak electricity. This Cycle also has the only statistically significant estimate for the conservation effect – an overall *increase* in consumption of nearly 2%. What is likely occurring is simply that, on average, households within this cycle have not responded to TOU prices at all, and the positive estimates for the two parameters discussed are simply capturing some average exogenous growth in consumption that occurred within this Cycle over the course of the period of analysis.

In the case of Cycle 29, although we can be reasonably confident that on average households reduced on-peak consumption (-3.42%) in response to TOU rates, we cannot confidently state which period this consumption has, on average, been shifted to or whether, on average it has been conserved. A plausible explanation, given the fact that none of the other parameters estimated for this Cycle are significant is simply that although households, on average, reduced their on-peak consumption, they redistributed it either inconsistently (within households) or idiosyncratically (across households), or both. An example of inconsistent redistribution might be a family which is careful not to use major household appliances during the on-peak period, but during all other periods uses them whenever it is most convenient – quasi-randomly. An example of idiosyncratic redistribution might be two households which both reduce on-peak demand but, perhaps because of differing schedules, redistribute it to different periods[1]. Likely some combination of both effects is at work.

As above, all parameters other than those highlighted in red in Table 10 below are statistically significantly different from zero at all conventional confidence levels.

Table 10 - Group Specific Demand Response Impact and Conservation Effect – Individual Fixed Effects

	Cycle 27		Cycle 28		Cycle 29	
	Parameter Estimate	Standard Error	Parameter Estimate	Standard Error	Parameter Estimate	Standard Error
On-peak	-4.31%	0.007306	-0.97%	0.007766	-3.42%	0.007555
Mid-peak	-5.42%	0.006716	0.16%	0.007075	0.90%	0.006612
Off-peak Weekdays	-0.82%	0.005916	1.03%	0.006445	0.13%	0.006095
Off-peak Weekends	3.74%	0.005383	1.88%	0.006185	0.82%	0.005908
Conservation effect	-0.99%	0.007808	1.97%	0.007664	0.54%	0.007256

[1] Note that while the individual level fixed effect will capture the effect of a constant, unchanging household schedule, it will not be able to capture the effect of that schedule changing, due to an addition to the family, for instance.

Overall and Group Specific Demand Response Impact and Conservation Effect – Two-ways Fixed Effects

To be consistent with the previous two assessments of TOU impacts estimated using fixed effects, and to allow a greater degree of comparability between studies, the results of the estimation of the conservation and demand response using two-way fixed effects are presented in Table 12 and Table 11 below.

The reader is cautioned not to assume that these results are a more accurate determination of the effect of TOU prices on demand response and conservation simply because there is a higher proportion of statistically significant results.

If we accept the assumption that the two principal drivers of daily electricity demand are the weather and whether or not a day is a holiday or weekend, and we further accept the assumption that, on average, residential consumers tend to adjust their consumption in a relatively consistent way to these drivers, then using individual fixed effects and explicitly controlling for both of these drivers by including them as variables will provide a more accurate estimate. Doing so allows us to take advantage of the great length of the time series and the attendant accumulation of information in the data in a way that simply assigning a dummy variable to each individual time period does not.

Table 11 - Overall Demand Response Impact and Conservation Effect - Two-way Fixed Effects

	Parameter Estimate	Standard Error
On-peak	-2.53%	0.0012856
Mid-peak	-1.87%	0.0010404
Off-peak Weekdays	0.34%	0.0009344
Off-peak Weekends	2%	0.0012745
Conservation effect	-0.23%	0.0020407

Table 12 - Group Specific Demand Response Impact and Conservation Effect - Two-way Fixed Effects

	Cycle 27		Cycle 28		Cycle 29	
	Parameter Estimate	Standard Error	Parameter Estimate	Standard Error	Parameter Estimate	Standard Error
On-peak	-5.57%	0.001585	-0.28%	0.001601	-1.28%	0.002002
Mid-peak	-4.50%	0.001428	0.16%	0.001866	-0.89%	0.001714
Off-peak Weekdays	-1.37%	0.001109	2.01%	0.001435	0.55%	0.001639
Off-peak Weekends	2.73%	0.001317	1.81%	0.001405	0.60%	0.001922
Conservation effect	-2.39%	0.002779	1.43%	0.002521	-0.15%	0.002179

To allow the reader to compare these results with those of the OEBSPP and the Hydro One TOU Pilot, the results from both of these studies are reproduced in **Table 13**, below. Neither study reports the demand response impact of TOU prices only for any TOU period other than the on-peak. The on-peak response was estimated for three different groups in the OEBSPP, only one of which was statistically significant and, counter-intuitively indicated that on-peak consumption had risen. The non-statistically significant results are not reported below.

Table 13 - Demand Response Impact and Conservation Effect Reported by Other Studies

	OEBSPP	Hydro One TOU Pilot
On-peak	10.80%	-3.70%
Conservation Effect	-6.00%	-3.30%

Additional Exploratory Analysis

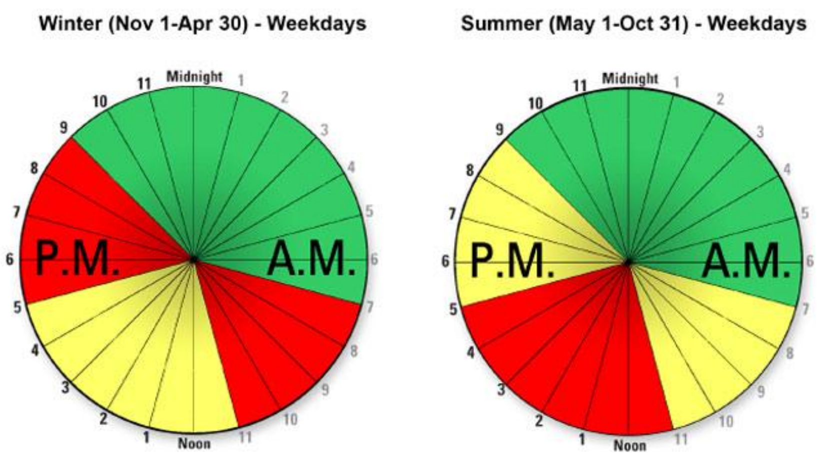
As an exploratory analysis, Navigant Consulting attempted to determine if the reduction in on-peak and mid-peak consumption estimated to be a result of TOU rates varied to any degree by season. To accomplish this, all of the one-way fixed effects models were re-estimated including two new independent variables. These new variables are what are sometimes referred to in econometric jargon as slope dummies or interaction terms. These new variables are the product of the TOU dummy and the number of cooling degree hours and the product of the TOU dummy and the number of heating degree hours.

As the name suggests, estimates of the parameters attached to these variables are estimates of the degree to which the dummy variable and the other independent variable of interest interact. This interaction proved to show an interesting result. Given the average number of cooling and heating degree hours in the winter and summer, the estimates obtained imply that during the summer there is almost no reduction in consumption during the mid-peak hours but considerable reduction during the on-peak hours and that in the winter there is almost no reduction in consumption during the on-peak hours but considerable reduction during the mid-peak hours.

The reader may observe in Figure 4 below[2] that under the current TOU rates, winter on-peak hours coincide exactly with summer mid-peak hours and that the summer on-peak hours coincide exactly with the winter mid-peak hours. The TOU schedule over the analysis period was slightly different as shown in Figure 4 on page 15, but the following discussion is based on the current TOU periods for simplicity and ease of understanding.

[2] From the OEB web-site, http://www.oeb.gov.on.ca/OEB/Consumers/Electricity/Electricity+Prices

Figure 4 – Current OEB TOU periods



By re-formatting the figure above so that it is linear and super-imposing the estimated reduction in winter and summer on-peak and mid-peak period consumption given the average number of heating or cooling degree hours per period the implications of these findings are clear; the majority of the reduction in consumption is occurring, in all seasons, in the hours between 11am and 5pm, regardless of whether on-peak or mid-peak rates apply..

Figure 5 – Seasonal Reductions in Consumption

	7am–11am	11am–5pm	5pm–9pm
Winter	0.0%	- 2.6%	0.0%
Summer	- 0.4%	- 5.4%	- 0.4%

On-peak period

Mid-peak period

Comparability with Results of 2007 NTP TOU Pilot

The results of this study generally accord with those found previously in the evaluation of NTP's TOU pilot; a modest decrease in the consumption of on-peak electricity and an increase in the consumption of off-peak electricity. The evaluation of the pilot program found a 1.7% drop in the total consumption during the on-peak period and a 1.1% drop in total consumption during the mid-peak period across all groups. The pilot evaluation also noted a slight increase in total off-peak consumption, although unlike the current study found that it was mostly concentrated during the weekday off-peak periods rather than the weekend. The pilot evaluation also noted a 1.1% *increase* in the average total energy consumption for all groups. This number was not tested for its statistical significance, but given the small sample size available for the pilot evaluation and the proximity of the estimate to zero, it is likely that this number is, as with the conservation effect (or lack thereof) noted above, statistically no different than zero. This study has shown results that are broadly consistent with the findings of the pilot evaluation but considerably more robust due to much greater sample size and quality of data available.

Survey Analysis

Concurrent with the econometric analysis undertaken above, NCI sub-contracted a market-research firm to conduct a telephone survey of the NTP customers whose consumption data were used to estimate the effect of TOU prices.

The survey was conducted by Northstar Research Partners between November 17th and December 4th, 2009. In total, surveys were completed by 10% of the customers in the original sample – detail by cycle is presented in Table 14 below. This response rate is exceptional. In past work of this kind Navigant Consulting has found many call-backs are necessary to achieve a response rates of even 5% among residential customers in a random survey.

Table 14 - Survey Completions

Cycle	Number of Respondents	Number of accounts in Billing Analysis	Response Rate	Date on TOU
26	99	883	11%	September 1, 2009
27	75	690	11%	December 1, 2007
28	71	840	8%	April 1, 2008
29	65	762	9%	May 1, 2008
TOTAL	**310**	**3175**	**10%**	N/A

Note that while for the duration of the period of analysis Cycle 26 customers were not billed on TOU rates by the time the survey was conducted, these customers had been moved over to TOU rates but had not yet received their first bill. As such they provide an almost ideal testing ground for how attitudes to TOU rates change over time.

The analysis of the data acquired from the survey is divided into two sub-sections. The first, directly below, explores the degree to which BICs – customers with perfect knowledge of the beginning and ending of all of the on-peak periods[3] – exceed the average response to TOU rates and identifies some of the other surveyed traits of this group. This is followed by a brief discussion of the possibilities such a group offers to NTP and indeed any party interested in encouraging a positive customer response to TOU rates.

The second sub-section presents more general findings of the survey and potential implications for NTP's efforts to improve TOU response among its customer base.

BICs and TOU response

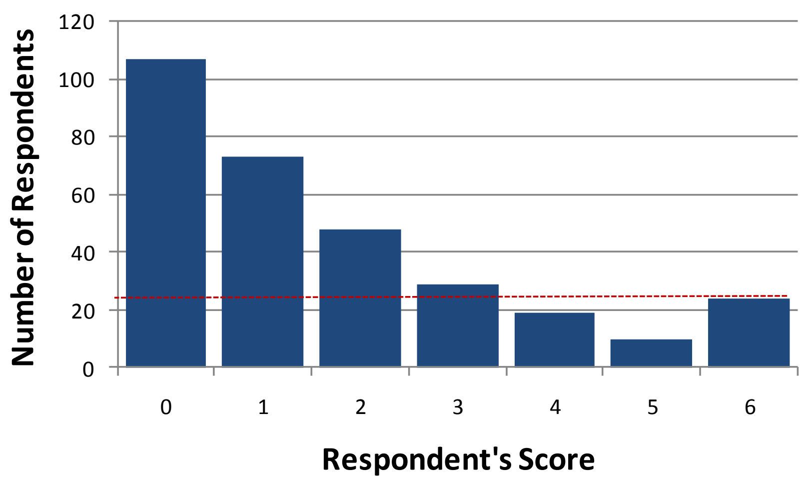
To test customer knowledge of TOU rates, all survey respondents were asked to identify the various times at which – in both summer and winter – the TOU rate changes. In analysing the survey data, each correct response was given a "mark" of one. Applied to the respondents' ability to identify the

[3] Two periods in winter, one in summer.

beginning and ending of each TOU period this means that each respondent will get a total score of between zero and six. A score of zero means that that respondent could not correctly identify the beginning or end of any on-peak TOU period, summer, winter, morning or afternoon.

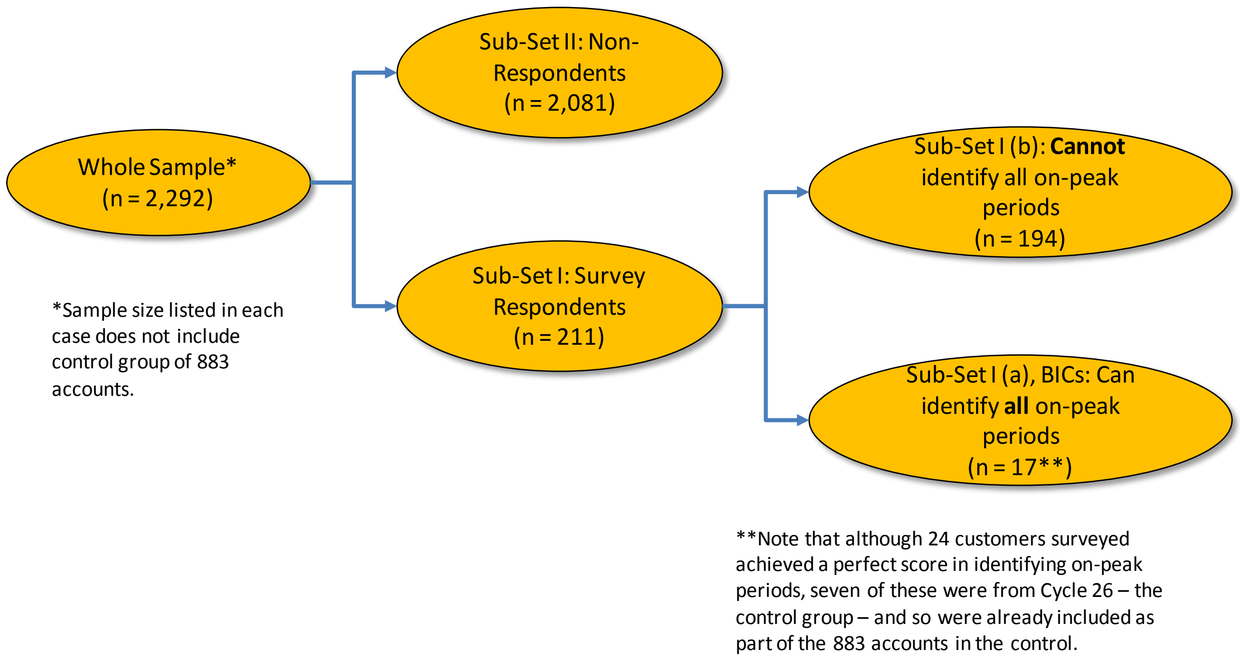
When plotted as a frequency diagram (Figure 6, below) this shows a striking result; up to a score of six (the best possible result) the results are what one would expect – that is that the number of people in each bin appears to be a declining function of that bin's score. What stands out, however, is the fact that the number of respondents in the highest scoring bin – those who could identify the beginning and ending of all on-peak periods – is not only higher than that of next bin down, but also than that of the bin below that.

Figure 6 - Ability to Identify On-Peak Period (6 = Perfect Score)



While this could simply be a statistical anomaly resulting from the sample of respondents surveyed, it does suggest that there is a group of consumers who are particularly well-informed regarding the TOU periods. That is, it suggests that there is a group amongst those surveyed that pays particular attention to when the on-peak period begins and ends. To attempt to quantify the degree to which these better-informed respondents were better able to respond to TOU rates, the estimation of the one-way fixed effects models was repeated for a number of different sub-sets of the entire sample. These sub-sets are described and shown in relation to one another in Figure 7 below.

Figure 7 - Sub-Sets of Whole Sample



BIC TOU Response

The econometric analysis outlined in the sections above was repeated for each of the subsets defined in Figure 7, above using only one-way fixed effects. The dummy parameter estimates for the change in on-peak, mid-peak, off-peak weekday and off-peak weekend, as well as for the conservation effect are shown below in Table 15. As previously, cells that are shaded in red indicate estimates that are not significant at the 95% confidence level.

Table 15 – Parameter Estimates Using Survey-Filtered Sub-Sets

Sub-Sample Name	Sub-Sample Description*	Sample Size**	On-peak	Mid-peak	Off-peak (Weekdays)	Off-peak (Weekends)	Conservation Effect
Whole Sample	Whole Sample	2292	-2.80%	-1.39%	0.16%	2.21%	0.66%
Sub-Set I	All Sample Customers Surveyed	211	-5.19%	-3.80%	1.97%	5.27%	1.55%
Sub-Set II	All Sample Customers Not Surveyed	2081	-2.55%	-1.17%	0.05%	2.01%	0.71%
Sub-Set I (a)	Best Informed Customers (BICs)	17	-15.60%	-13.68%	0.98%	8.13%	-5.16%
Sub-Set I (b)	All Non-BIC Customers Surveyed	194	-4.25%	-2.95%	2.07%	5.09%	2.17%

*All sub-sets include the control group ** Not including control group of 883 accounts

Note that the sample size cited for each sub-set in the table above does not include the 883 accounts of the control group, thus even Sub-Set I (a), the BIC group, is actually made up of 900 accounts, a very robust sample size for this estimation.

Two things are clear from this exercise:

1. The NTP customers that agreed to answer the telephone survey have a better response to TOU rates than the average. This could be pure chance, or it could indicate that those better disposed to TOU rates (and thus more likely to have a positive behavioural response to the rate change) are more ready to discuss such rates on the telephone with a stranger for twenty minutes than customers that are indifferent. This self-selection bias should be borne in mind when considering all other survey responses cited in this study and when comparing these results across other study surveys relying on self-selected recruitment.
2. BICs appear on average to have a considerably stronger response to TOU rates than the rest of the customer population.

It is clear then that there is a strong correlation between a customer's knowledge of when the peak periods are and his or her ability to shift demand away from them. It is unclear, however in which direction the causation flows – is it that better informed customers are better at shifting, or is it that customers more interested in shifting are better informed? Likely it is some combination of both – knowledge of the TOU periods is clearly a pre-condition to efficient shifting, and a desire to shift or conserve energy is likely a sufficient – though not necessary – condition for the acquisition of knowledge of the TOU periods.

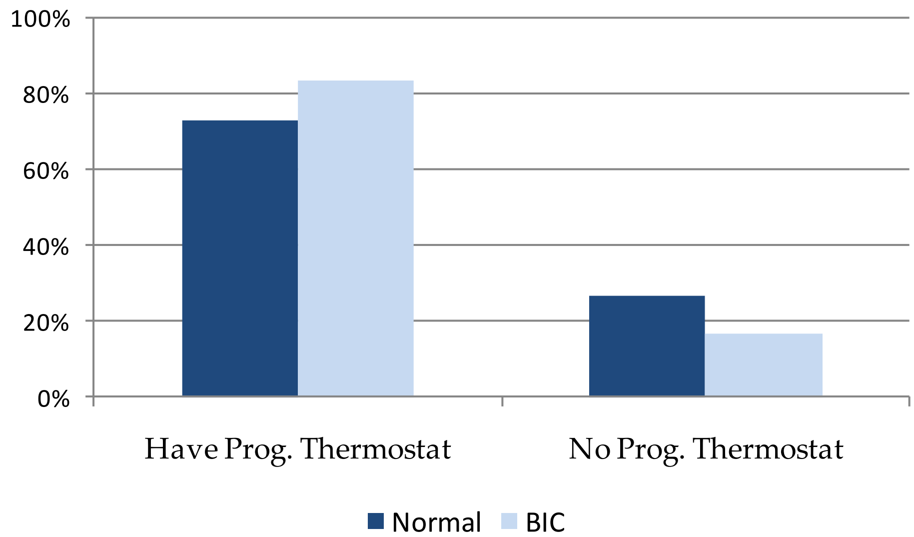
Other BIC Household Characteristics

Having identified that a sub-set of customers exist that tend to have an above average response to TOU rates, Navigant Consulting explored what, if any, other characteristics covered by the survey are common to this group. Caution must be exercised, however, in applying any of the following results to other jurisdictions or programs.

Surprisingly, none of the BICs in the sample have either electric space or water heating, although given the very high natural gas fuel share in NTP's territory this should not be too surprising, it does indicate that natural gas space heating does not preclude significant demand shifting.

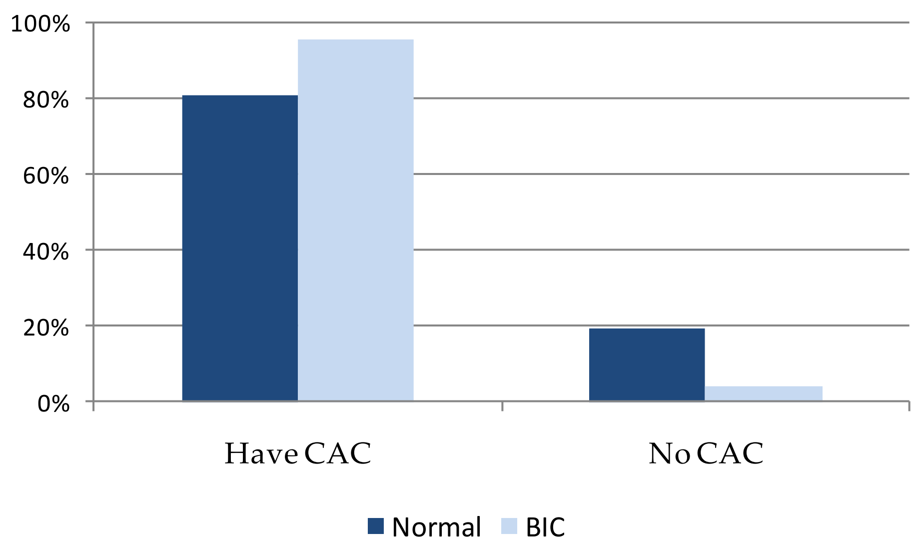
Equally surprisingly, BICs appear to be about as likely to have participated in some kind of energy conservation program as the rest of the population, and they tend to be only a little more likely to have programmable thermostats than the rest of the population (see Figure 8, below).

Figure 8 - Incidence of Programmable Thermostat Ownership



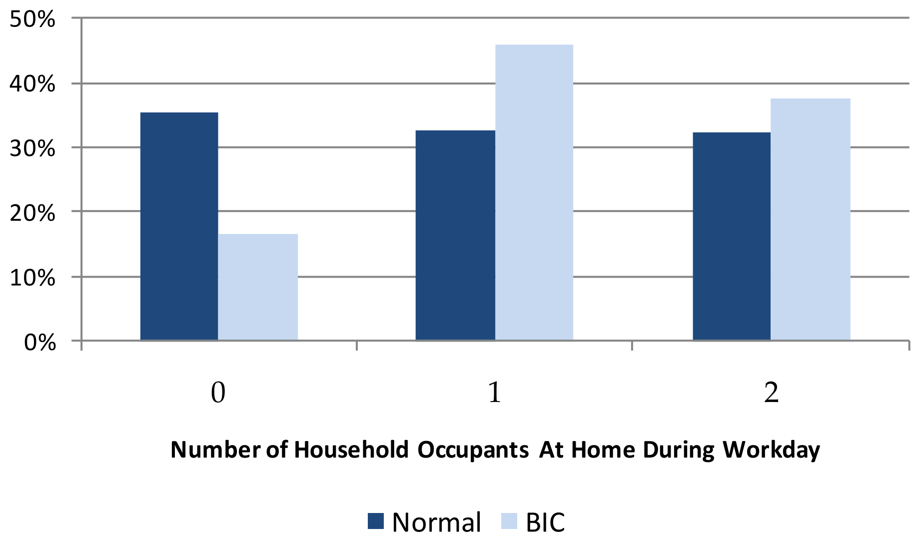
Likewise, although BICs appear to have a higher incidence of central air-conditioner ownership than the rest of the sample, the difference may simply be due to random sample variation (see Figure 9, below).

Figure 9 - Incidence of CAC Ownership



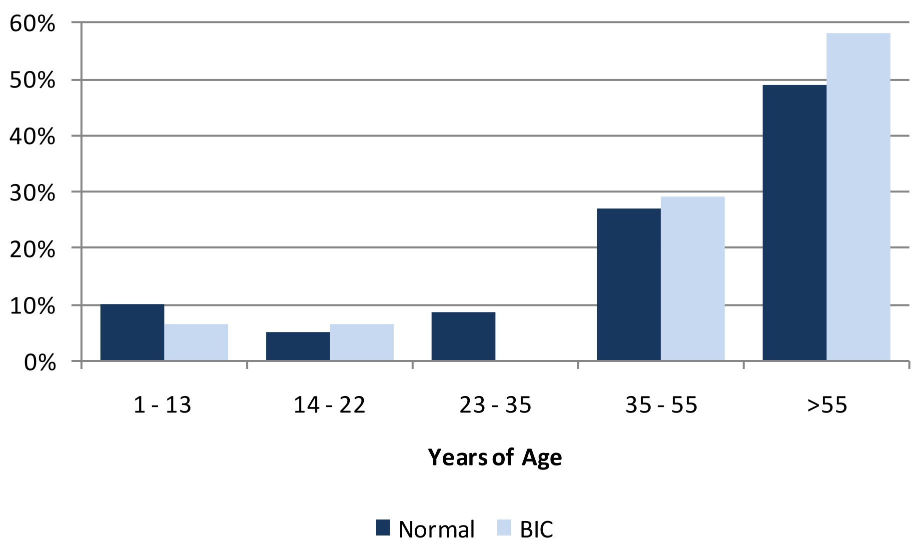
The survey also reveals that BIC households are more likely to have one or more residents that spend at least three days during the work week (i.e. during the on-peak or mid-peak hours) at home (see Figure 10, below).

Figure 10 - Incidence of Workweek Occupancy



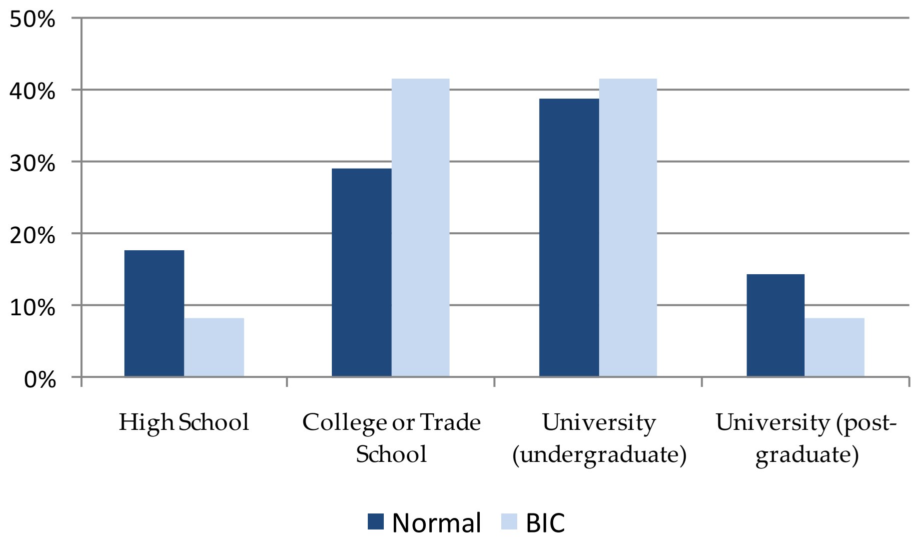
Although no data regarding the ages of respondents was collected, the ages of those occupants who spent at least three days of the workweek at home during workdays was. This distribution is presented in below. From this it may be inferred that the age of BIC respondents was relatively representative of the age distribution with the surveyed sample as a whole, although there does appear to a slight skew among BIC respondents towards older workweek occupants.

Figure 11 – Age Distribution of Workday Occupants



BICs do not appear to differ very much in the degree of educational attainment by household either, although they appear to tend to have fewer occupants for whom high school is the highest degree of educational attainment (see Figure 12).

Figure 12 - Level of Educational Attainment



The BIC Opportunity

The econometric analysis of the sub-sets presented above appears to indicate the possibility of two opportunities for NTP to increase TOU response amongst its customer base:

1. **Make more of the customer base like the survey sample.**

Since the survey sample has been shown to be composed of customers who, on average, exceeded the reduction in consumption of the majority of the sample, bringing the rest of the customer population up to this level could significantly reduce on-peak and mid-peak consumption. The problem however is that the characteristics (other than consumption profiles) of the rest of the sample are, by definition unknown making this opportunity impossible to pursue.

2. **Make more of the customer base like the BIC respondents.**

BICs have been identified as customers with a perfect knowledge of when on-peak periods begin and end and have been shown to have reduced their consumption on-peak and mid-peak considerably more than the average. Unfortunately, given the small sample size, these are the only two characteristics of these customers of which we can be reasonably certain. Nonetheless, what is known about these customers suggest that they represent a significant opportunity for NTP and policy-makers interested in increasing customer response to TOU rates. Clearly, the aggregate customer response to TOU rates can be improved by increasing the ratio of BICs to the rest of the population. Two approaches suggest themselves.

The motivation for BICs must be either pecuniary or "green". It is generally recognized that consumers will be more willing to adopt "green" behaviours when those behaviours, or the results thereof, may be observed by their peers. Although the cost differential between paying 5 cents for a single disposable grocery bag or two dollars for a canvas one are (over time, at least) negligible, the canvas bags advertise the carrier's environmental virtue.

Although TOU response may be generally regarded as a "green" behaviour there is not currently any way for customers to advertise the fact that they are any "greener" (i.e. shift or conserve more) than their neighbours. A well-thought out publicity campaign to publicly recognize cooperative BICs, perhaps in conjunction with some on-going competition for "most reduced on-peak consumption of the month" could take advantage of these social pressures.

The second opportunity is in some ways less direct. These BICs represent potentially valuable allies to NTP in encouraging the wider customer base to adopt BIC strategies and behaviours. Studies of consumer choice tend to agree that it is the opinions of a consumer's peers rather than advertising or even third-party review that most influence a consumer's choice of a product or service. If BICs can be publicly acknowledged as discussed above, there is an opportunity for NTP to co-opt these BICs as "TOU Ambassadors" to encourage greater TOU response amongst their peer group, ideally selecting one or more from each of the most significant demographic groups in the Newmarket service area.

Although it is regrettable that the small sample size and the limits on the scope of this study preclude any very robust exploration of the possibilities and characteristics of this BIC demographic, there appears to be sufficient evidence to warrant greater investigation of this potential in future research.

Other Survey Findings

The BICs identified above are remarkable in that they could identify both the beginning and ending times of all on-peak periods (summer and winter), however these BICs make up only 8% of the customers who responded to the survey. Fortunately, it appears that despite the general inability of survey respondents to correctly identify the time-span of *all* on-peak periods, the beginning or ending of each on-peak period could be identified correctly by between 20% and 40% of respondents.

While there is clearly work to be done to improve individuals' recall of the on-peak periods, customers as a whole appear to have a reasonable level of recall of when on-peak periods begin and end. Table 16, below shows the percent of survey respondents who correctly identified each beginning or ending time of the on-peak period as well as the percent of survey respondents that identified an incorrect beginning or ending time that was within one hour or within two hours of the correct time.

Table 16 - Survey Respondent Recall of On-Peak Periods

		Correct	Within 1 hour	Within 2 hours	More than 2 hours off/didn't know
		% are cumulative			
Summer	Start of On-Peak	**19%**	27%	32%	68%
	End of On-Peak	**26%**	33%	41%	59%
Winter	Start of AM On-Peak	**40%**	57%	64%	36%
	End of AM On-Peak	**31%**	43%	46%	54%
	Start of PM On-Peak	**34%**	50%	55%	45%
	End of PM On-Peak	**21%**	33%	42%	58%
	Average	**28%**	**40%**	**46%**	**54%**
	Summer Average	**22%**	30%	36%	64%
	Winter Average	**31%**	46%	51%	49%

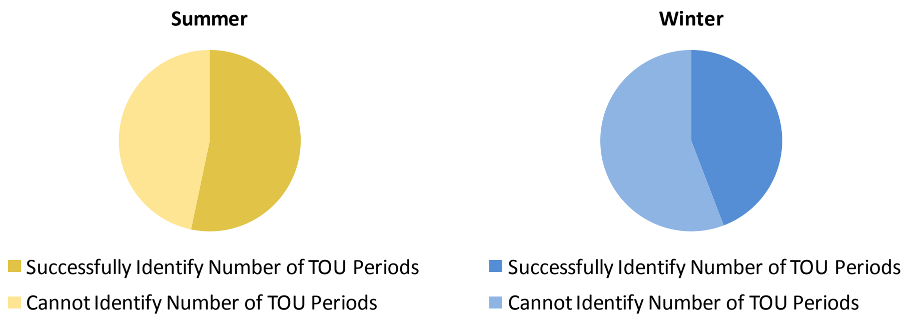
If it is understood that the *sine qua non* of demand shifting and TOU response is knowing when the TOU periods – in particular the on-peak period – occur, Table 16 allows to estimate an upper bound for the percent of customers that are knowingly responding to TOU rates. On average, 36% of survey respondents could come within two hours of identifying the beginning or end time of the summer on-peak period and 51% could come within two hours of identifying the beginning or ending of either the morning or afternoon winter on-peak periods.

It is interesting to note that the period which survey respondents consistently had the greatest difficulty identifying was the start of the summer on-peak period. For all other periods, incorrect answers were relatively evenly distributed throughout the day, however for the start of the summer on-peak period, 14% of respondents said that it occurred at 7am rather than 11am. No other incorrect answer for any of the other on-peak periods occurred with similar consistency.

It is unclear why customers so frequently identified 7am as the start of the on-peak period in the summer, although two possibilities suggest themselves. First, it could be the result of previous provincial and utility efforts at TOU awareness which split the day into only two periods, on-peak and off. The second, more likely, possibility is that respondents were confusing winter on-peak times with summer (recall that the morning winter on-peak period begins at 7am).

Encouragingly, however, nearly half of the survey respondents could identify how many TOU periods there are during the winter months, and more than half of survey respondents could identify how many TOU periods there are during the summer months (see Figure 13, below).

Figure 13 - Survey Respondents Ability to Identify Number of TOU Periods



Survey respondents were asked a number of questions regarding the materials provided to them by NTP to help them identify and respond to the TOU periods. In particular respondents were asked both what materials they recalled receiving and, of the materials they recalled receiving, which was most useful to them in understanding TOU rates.

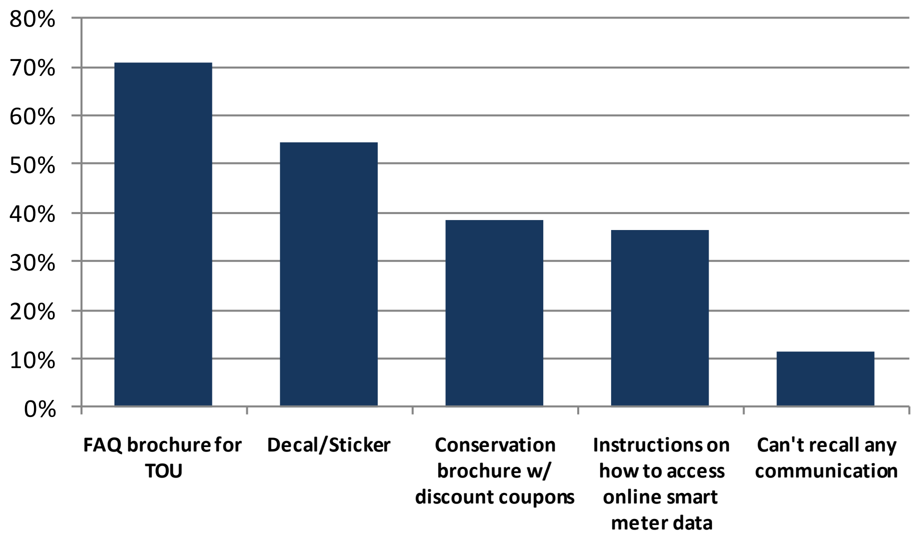
Cross-tabulating the responses of those surveyed who correctly identified the beginning or ending of the on-peak period in either summer or winter with the information that respondents had identified as being most helpful in understanding TOU rates shows unequivocally that the better-informed customers found the decal provided by NTP to be the most useful piece of information. As may be observed below, on average 63% of those who correctly identified the beginning or ending of the on-peak periods in summer or winter most preferred the decal.

Figure 14 - Information Most Helpful in Understanding TOU Rates Provided to Respondents

		Sticker/Decal Showing TOU Periods	FAQ Brochure	All Other Communications/ Don't Know
		% below indicate the distribution of answers within the sub-group that correctly identified start/end time of the on-peak period shown at left		
Summer	Start of On-Peak	68%	22%	10%
	End of On-Peak	56%	31%	13%
Winter	Start of AM On-Peak	54%	36%	11%
	End of AM On-Peak	66%	26%	8%
	Start of PM On-Peak	65%	26%	9%
	End of PM On-Peak	69%	22%	8%
Average		63%	27%	10%

The result above suggests that the TOU decal is likely the most successful communication tool used by NTP in terms of informing customers about the times of TOU periods. It is striking therefore that nearly half of the respondents could not remember receiving it (see Figure 15, below).

Figure 15 - Communication Tools That Respondents Recall Receiving

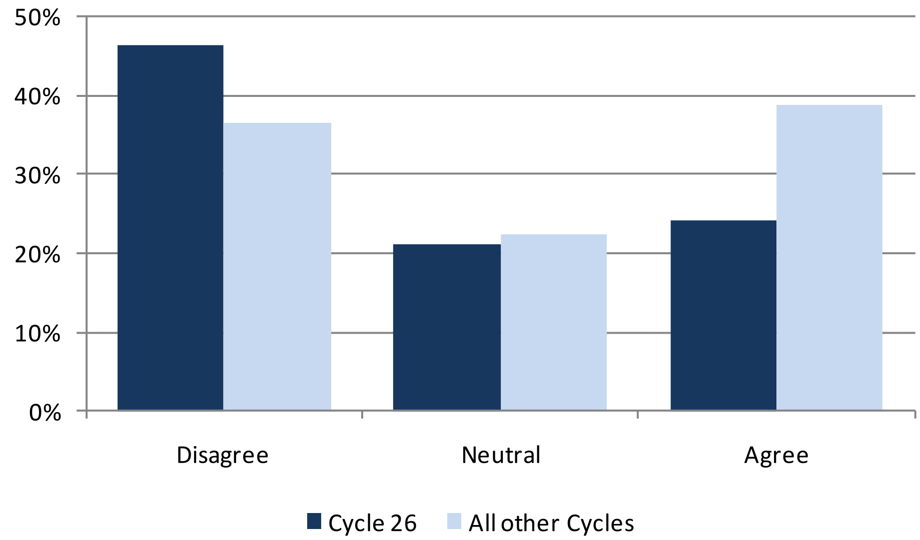


This lack of recall of receiving the decal within the general sample, the indication that the better-informed customers most prefer this communication tool and the observation above that there appears to be considerable confusion amongst the respondents between the beginning of on-peak in summer and winter all suggest that providing customers with a new decal at the beginning of each season (winter and summer) could improve overall customer knowledge of on-peak periods. While such improved knowledge would not guarantee an overall improved customer response to TOU rates, it is necessary prerequisite to improved customer response.

Survey respondents were also asked to provide input on how they felt about TOU rates in general. Respondents were asked whether they agreed that TOU rates are an appropriate way to incent customers to shift demand or conserve energy and whether they felt that they were paying more, less or the same as they had been before the implementation of TOU rates. In this case, dividing the responses into two groups allows for an exploration of how such attitudes change over time. Cycle 26, used as the control group in the econometric analysis, only became subject to TOU rates on September 1st, whereas the respondents from the other three cycles would have become subject to TOU rates much earlier – May of 2008 at the very latest.

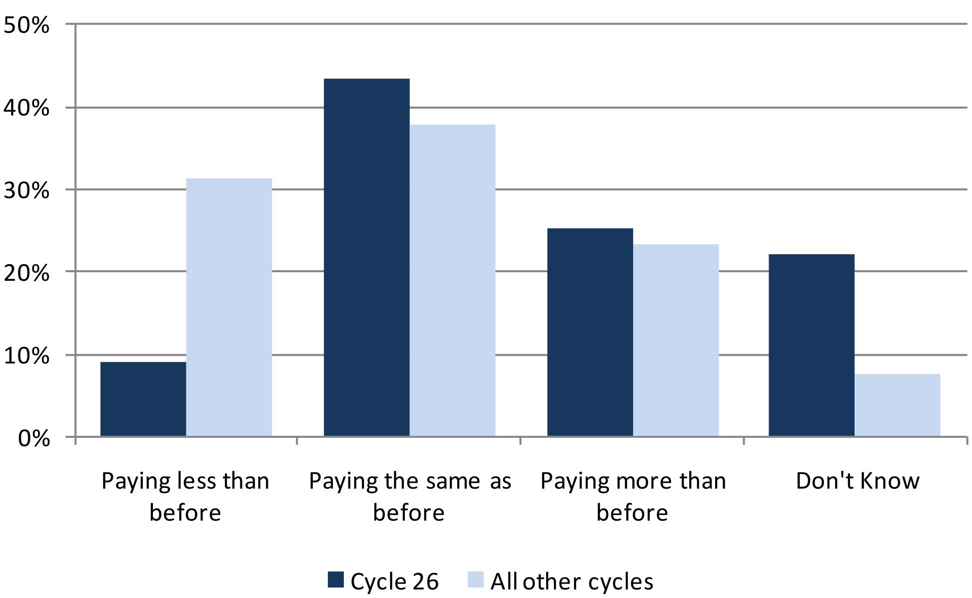
It seems likely then, given the manner in which the responses of Cycle 26 respondents differed from those of respondents from all other cycles, that over time, as customers become more accustomed to TOU rates, they also come to agree with the statement that TOU prices are an appropriate way to encourage customers to shift their demand and conserve energy (see below).

Figure 16 – Survey Response to Appropriateness of TOU Rates to Encourage Shifting and Conservation



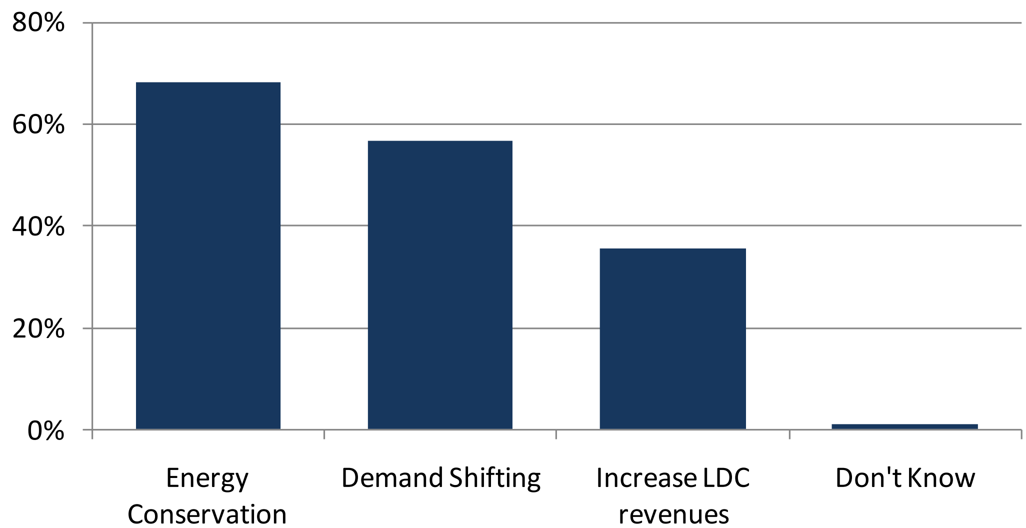
Likewise, survey responses from Cycle 26 indicate that very few (less than 10%) believed that they were paying less for their electricity than they had previous to the implementation of TOU rates, and over 20% weren't sure, whereas for the other cycles with more experience, the situation was the reverse with approximately a third of respondents indicating that they believe that they are paying less than before and fewer than 10% who didn't know (see below).

Figure 17 – Respondent Belief Regarding Change in Electricity Bill Since Becoming Subject to TOU Rates



While these results are encouraging from the perspective of evolving public acceptance of TOU rates there are indications that TOU rates are regarded with some cynicism by the public. Over a third of respondents indicated (see below) that they believed that TOU rates were, at least in part, being implemented as a way to increase the revenues of local distribution companies (LDCs). It is impossible to know how virulent such cynicism is and how much it might affect a customer's willingness to shift demand or conserve energy – but the fact that a clear majority understand that TOU rates are a tool to encourage conservation and shifting[4] would seem to indicate that it is an idle rather than an active cynicism. Given the monopolistic position of LDCs, it is likely analogous to cynicism popularly felt regarding gasoline prices. While not an immediate concern for NTP, correcting this public misunderstanding of the purpose of TOU rates will likely pay long-term dividends in terms of public participation in TOU response and acceptance of TOU rates.

Figure 18 – Respondents' Opinions Regarding the Purpose of TOU Rates



Other Quantitative Survey Analysis Attempted.

In designing the survey for this study, Navigant Consulting included a battery of questions to isolate household changes occurring in the period of analysis which would have a significant impact on household consumption. These included questions regarding the number of members of the house (whether any had joined or left in the period of observation), fuel switching (from electric to natural gas for space and water heating and vice versa) as well as questions regarding major changes in respondents' daily routines – for example, had anyone retired or changed working shift.

It was hoped that the answers to these questions would allow Navigant Consulting to control for exogenous changes in consumption on an individual level and thus estimate the TOU effect on individual time series of consumption data, net of household consumption changes unrelated to TOU pricing. It was hoped that if the TOU effect could reliably be estimated on an individual level, this (cross-sectional) series of parameter estimates of the TOU effect could then be used as the dependent variable, regressed on a variety of household characteristics. That is, it was hoped that a more

[4] Note that these opinions are not mutually exclusive. Some respondents believe both that TOU rates are designed to encourage conservation and shifting *and* are meant to increase LDC revenues.

quantitative approach to identifying the characteristics of customers with a strong TOU response could be used. For example, it was thought that it might be possible to test the relationship between those customers who favoured the decal and their change in consumption.

Unfortunately even after controlling for the exogenous changes in consumption discussed above, there remained too much random variation within the data to produce credible or statistically significant results. It was concluded the approach above, a two-step regression, would only yield strong results if data were available on daily participant behaviours – that is if respondents were to keep daily diaries which could be translated into useable regressors.

Although no very robust results were obtained from this analysis, it was felt that it would be valuable to discuss what had been attempted in case future researchers wish to explore this method of analysis.

CONCLUSIONS

The three principal objectives of this study were to:

1. Estimate the degree to which the introduction of TOU rates had encouraged residential consumers to shift their consumption away from the on-peak period.
2. Estimate the degree to which the introduction of TOU rates had encouraged residential consumers to reduce their consumption of all electricity – the conservation effect.
3. Use survey data obtained from NTP customers whose consumption data had been used to achieve the first two objectives to identify opportunities for improving residential TOU response; shifting away from on-peak and mid-peak periods toward off-peak periods.

Objective 1: Demand Shifting

The overall impact that TOU prices have had on three groups of NTP customers are modest, but significant; households appear to have, overall, shifted their consumption away from the on-peak and mid-peak periods to off-peak weekends. Just as significant, it appears that they are not, overall, shifting their consumption toward off-peak weekdays as a result of TOU prices.

Objective 2: Conservation Effect

Navigant Consulting detected no statistically significant conservation impact as a result of the introduction of TOU rates. This result is not surprising. The entire purpose of TOU rates is to encourage consumers to shift demand rather than reduce their overall consumption. Conservation comes about as a result of households acquiring more efficient electricity-consuming devices, acquiring other measures which reduce their need for those devices or from pure behavioural change. The incremental financial impact of TOU over tiered rates alone is too small to (for most energy efficiency measures) make the first two options any more attractive than they would otherwise have been in terms of payback. Experience has shown that for behavioural changes to have a significant impact on energy conservation (or, indeed, any other activity) they require a considerable amount of time to acquire societal inertia. It is possible that as TOU rates become more common-place (i.e. affect a considerable proportion of the population) behavioural changes as a result of TOU rates could lead to a net conservation effect, but, for the Newmarket sample over the study period at least, this is not yet the case.

Objective 3: Opportunities to Improve TOU Response and Customer Attitudes to TOU

The principal quantitative result of the survey analysis was to confirm that the impact of TOU rates on the consumption patterns of BICs is significantly stronger than on the population in general. Although, due to the small sample size of the BICs, it is difficult to conclusively identify any characteristics that define this group other than their exceptional response to TOU rates, it is clear that the existence of this group offers significant opportunities for NTP to improve overall customer response to TOU rates.

By actively engaging with BICs and perhaps offering them public recognition as “green” citizens NTP could conceivably increase the willingness of the rest of its customer base to engage in TOU response as positive “green” action.

Additionally, it is clear that customers will, other things equal, reduce consumption more on-peak and mid-peak when they are aware of when those periods are and that the best tool currently employed to communicate this information is also in many ways the simplest – the decal or sticker indicating the TOU periods. Given the confusion between the beginning of the on-peak period in winter and summer that was observed, and the fact that overall only half of the respondents could remember receiving the decal, it would be advisable for NTP to provide its customers with a new decal on a seasonal basis.

Finally, a strong correlation was observed between the length of time customers were subject to TOU rates and the degree to which they felt positive about them. Far fewer customers who had recently become subject to TOU rates felt that they were paying less under the TOU regime than customers that had been subject to them for more than a year. More customers who had been subject to TOU rates for longer felt that they are an appropriate way to encourage consumer energy conservation and demand shifting.

Appendix A – Model Details

Demand Response Impact – Individual fixed effects

All individual fixed effects models were estimated using STATA 10, and tested using a robust "sandwich" estimator to obtain standard errors.

Model A1:

To estimate the demand response impact of TOU prices in all non-holiday weekday TOU periods, the following model was estimated:

$$y_{i,t} = \propto_i + Dum27_{i,t} * \beta_1 + Dum28_{i,t} * \beta_2 + Dum29_{i,t} * \beta_3 + CDH_t * \gamma_1 + HDH_t * \gamma_2 + NonWorkDay_t * \gamma_3 + \varepsilon_{i,t}$$

Where:

$y_{i,t}$ is the natural logarithm of consumption for customer i during the on-peak/mid-peak/off-peak hours of day t[5].

$\propto_i$ is the individual household level fixed effect.

$\varepsilon_{i,t}$ is the error for household i, in day of sample t

β_1, β_2 and β_3 are the percentage change in *weekday* consumption during on-peak/mid-peak/off-peak hours due to TOU rates for the three experimental groups

CDH_t is the number of cooling degree hours during the on-peak/mid-peak/off-peak period of day t

HDH_t is the number of heating degree hours during the on-peak/mid-peak/off-peak period of day t

$NonWorkDay_t$ is a dummy equal to one if day t is a public holiday or a weekend and zero otherwise

γ_1 is the percentage change in consumption during on-peak/mid-peak/off-peak hours due to an additional cooling degree hour in the weekday on-peak/mid-peak/off-peak period

γ_1 is the percentage change in consumption during on-peak/mid-peak/off-peak hours due to an additional heating degree hour in the weekday on-peak/mid-peak/off-peak period

γ_1 is the percentage change in consumption during on-peak/mid-peak/off-peak hours due to a day being a holiday or weekend

$Dum27_{i,t}$, $Dum28_{i,t}$ and $Dum29_{i,t}$ are all dummy variables. These dummies all calculated in the following manner (example for $Dum27_{i,t}$ only):

$$Dum27_{i,t} = Cycle27_i * TOU_t * WorkDay_t$$

Where:

[5] Note that this includes weekends. Although all hours during the weekend or holiday are considered "off-peak" for billing purposes, for estimation of this model all hours during weekends and holidays were also divided into the three periods.

$Cycle27_i$ is a dummy equal to one if household i is in Cycle 27 and zero otherwise

TOU_t is a dummy equal to one if by day t that experimental group or cycle has been switched from tiered to TOU rates and zero otherwise

$WorkDay_t$ is a dummy equal to one if day t is a non-holiday weekday.

Model A2:

To estimate the demand response impact of TOU prices on weekend and holiday off-peak consumption, the following model was estimated:

$$y_{i,t} = \propto_i + Dum27_{i,t} * \beta_1 + Dum28_{i,t} * \beta_2 + Dum29_{i,t} * \beta_3 + CDH_t * \gamma_1 + HDH_t * \gamma_2 + NonWorkDay_t * \gamma_3 + \varepsilon_{i,t}$$

Where:

$y_{i,t}$ is the natural logarithm of total consumption for customer i on day t.

$\propto_i$ is the individual household level fixed effect.

$\varepsilon_{i,t}$ is the error for household i, in day of sample t

β_1, β_2 and β_3 are the percentage change in *weekend and holiday* consumption due to TOU rates for the three experimental groups

CDH_t is the total number of cooling degree hours on day t

HDH_t is the total number of heating degree hours on day t

$NonWorkDay_t$ is a dummy equal to one if day t is a public holiday or a weekend and zero otherwise

γ_1 is the percentage change in daily consumption due to an additional cooling degree hour.

γ_1 is the percentage change in daily consumption due to an additional heating degree hour.

γ_1 is the percentage change in daily consumption due to a day being a holiday or weekend

$Dum27_{i,t}$, $Dum28_{i,t}$ and $Dum29_{i,t}$ are all dummy variables. These dummies all calculated in the following manner (example for $Dum27_{i,t}$ only):

$$Dum27_{i,t} = Cycle27_i * TOU_t * NonWorkDay_t$$

Where:

$Cycle27_i$ is a dummy equal to one if household i is in Cycle 27 and zero otherwise

TOU_t is a dummy equal to one if by day t that experimental group or cycle has been switched from tiered to TOU rates and zero otherwise

$NonWorkDay_t$ is a dummy equal to one if day t is a holiday or weekend.

Model A3

In addition to estimating the impact of TOU rates on the three experimental groups individually, NCI estimated the weekday demand response impact of TOU rates on the aggregate sample of customers affected. To estimate the overall demand response impact of TOU rates on all the weekday on-peak/mid-peak/off-peak consumption of all customers, the following model was estimated:

$$y_{i,t} = \propto_i + DumAll_{i,t} * \beta_1 + CDH_t * \gamma_1 + HDH_t * \gamma_2 + NonWorkDay_t * \gamma_3 + \varepsilon_{i,t}$$

Where:

β_1 is the percentage change in *weekday* consumption during on-peak/mid-peak/off-peak hours due to TOU rates for all three experimental groups

$DumAll_{i,t}$ is a dummy variable calculated in the following manner:

$$DumAll_{i,t} = TOU_{i,t} * WorkDay_t$$

Where:

$TOU_{i,t}$ is a dummy equal to one if by day t household i has switched from tiered to TOU rates and zero otherwise.

$WorkDay_t$ is a dummy equal to one if day t is a non-holiday weekday.

All of the rest of the variables for model A3 are defined the same way as they are for model A1.

Model A4

This model follows the same exercise as model A3; it is used to estimate the weekend demand response impact of TOU rates on the aggregate sample of customers affected. The following model was estimated:

$$y_{i,t} = \propto_i + DumAll_{i,t} * \beta_1 + CDH_t * \gamma_1 + HDH_t * \gamma_2 + NonWorkDay_t * \gamma_3 + \varepsilon_{i,t}$$

Where:

β_1 is the percentage change in *weekend and holiday* consumption due to TOU rates

$DumAll_{i,t}$ is a dummy variable calculated in the following manner:

$$DumAll_{i,t} = TOU_{i,t} * NonWorkDay_t$$

Where:

$TOU_{i,t}$ is a dummy equal to one if by day t household i has switched from tiered to TOU rates and zero otherwise.

$NonWorkDay_t$ is a dummy equal to one if day t is holiday or weekend and zero otherwise

All of the rest of the variables for model A4 are defined the same way as they are for model A2.

Conservation Effect – Individual fixed effects

Model B1

To estimate the conservation effect of TOU prices, the following model was estimated:

$$y_{i,t} = \propto_i + Dum27_{i,t} * \beta_1 + Dum28_{i,t} * \beta_2 + Dum29_{i,t} * \beta_3 + CDH_t * \gamma_1 + HDH_t * \gamma_2 + Holiday_t * \gamma_3 + \varepsilon_{i,t}$$

Where:

$y_{i,t}$ is the natural logarithm of total consumption for customer i during week t

$\propto_i$ is the individual household level fixed effect.

$\varepsilon_{i,t}$ is the error for household *i,* in week of sample t

β_1, β_2 and β_3 are the percentage change in weekly consumption due to TOU rates for the three experimental groups

CDH_t is the number of cooling degree hours in week t

HDH_t is the number of heating degree hours in week t

$Holiday_t$ is the number of non-weekend holidays that occur in week t

γ_1 is the percentage change in total weekly consumption due to an additional weekly cooling degree hour

γ_1 is the percentage change in total weekly consumption due to an additional weekly heating degree hour

γ_1 is the percentage change in weekly consumption due to an additional holiday occurring during the week

$Dum27_{i,t}$, $Dum28_{i,t}$ and $Dum29_{i,t}$ are all dummy variables. These dummies all calculated in the following manner (example for $Dum27_{i,t}$ only):

$$Dum27_{i,t} = Cycle27_i * TOU_t$$

Where:

$Cycle27_i$ is a dummy equal to one if household *i* is in Cycle 27 and zero otherwise

TOU_t is a dummy equal to one if by week *t* that experimental group or cycle has been switched from tiered to TOU rates and zero otherwise

Model B2

As with the demand response impact, in addition to estimating the magnitude of the conservation effect on each individual experimental group, NCI estimated the magnitude of the conservation effect for the aggregate sample of all those on TOU rates. The following model was estimated:

$$y_{i,t} = \propto_i + DumAll_{i,t} * \beta_1 + CDH_t * \gamma_1 + HDH_t * \gamma_2 + Holiday_t * \gamma_3 + \varepsilon_{i,t}$$

Where:

β_1 is the percentage change in weekly consumption due to TOU rates

$DumAll_{i,t}$ is a dummy equal to one if by week *t* household *i* has been switched from tiered to TOU rates and zero otherwise

All the rest of the variables for model B2 are defined in the same way as for model B1.

Demand Response Impact – Two-way fixed effects

Although NCI is confident that the individual fixed effects used to estimate models A1 – 4 and B1 and B2 provide a more accurate estimate of the true impact of TOU prices on demand response and energy conservation by explicitly controlling for the time-variant drivers - particularly holidays and weekends – of electricity demand, NCI has, to allow a greater degree of direct comparison between studies also estimated demand response and conservation impacts using two-way fixed effects. The models used are presented below.

All two-way fixed effects models were estimated using the **a2reg** STATA module[6] and standard errors were computed by bootstrapping.

Model C1

To estimate the demand response impact of TOU prices in all non-holiday weekday TOU periods using two-way fixed effects, the following model was estimated:

$$y_{i,t} = \propto_i + \tau_t + Dum27_{i,t} * \beta_1 + Dum28_{i,t} * \beta_2 + Dum29_{i,t} * \beta_3 + \varepsilon_{i,t}$$

Where:

$y_{i,t}$ is the natural logarithm of consumption for customer *i* during the on-peak/mid-peak/off-peak hours of day t.

$\propto_i$ is the individual household level fixed effect.

τ_t is the day of sample level fixed effect

$\varepsilon_{i,t}$ is the error for household *i,* in day of sample *t*

β_1, β_2 and β_3 are the percentage change in *weekday* consumption during on-peak/mid-peak/off-peak hours due to TOU rates for the three experimental groups

$Dum27_{i,t}$, $Dum28_{i,t}$ and $Dum29_{i,t}$ are all dummy variables. These dummies all calculated in the following manner (example for $Dum27_{i,t}$ only):

$$Dum27_{i,t} = Cycle27_i * TOU_t * WorkDay_t$$

Where:

$Cycle27_i$ is a dummy equal to one if household *i* is in Cycle 27 and zero otherwise

TOU_t is a dummy equal to one if by day *t* that experimental group or cycle has been switched from tiered to TOU rates and zero otherwise

$WorkDay_t$ is a dummy equal to one if day *t* is a non-holiday weekday.

Model C2

To estimate the demand response impact of TOU prices on weekend and holiday off-peak consumption using two-way fixed effects, the following model was estimated:

$$y_{i,t} = \propto_i + \tau_t + Dum27_{i,t} * \beta_1 + Dum28_{i,t} * \beta_2 + Dum29_{i,t} * \beta_3 + \varepsilon_{i,t}$$

Where:

$y_{i,t}$ is the natural logarithm of total consumption for customer *i* on day t.

[6] Ouazad, Amine, (2008), *A2REG: Stata module to estimate models with two fixed effects*, Statistical Software Components, Boston College Department of Economics

$\propto_i$ is the individual household level fixed effect.

τ_t is the day of sample level fixed effect.

$\varepsilon_{i,t}$ is the error for household *i,* in day of sample *t.*

β_1, β_2 and β_3 are the percentage change in *weekend and holiday* consumption due to TOU rates for the three experimental groups.

$Dum27_{i,t}$, $Dum28_{i,t}$ and $Dum29_{i,t}$ are all dummy variables. These dummies all calculated in the following manner (example for $Dum27_{i,t}$ only):

$$Dum27_{i,t} = Cycle27_i * TOU_t * NonWorkDay_t$$

Where:

$Cycle27_i$ is a dummy equal to one if household *i* is in Cycle 27 and zero otherwise

TOU_t is a dummy equal to one if by day *t* that experimental group or cycle has been switched from tiered to TOU rates and zero otherwise

$NonWorkDay_t$ is a dummy equal to one if day *t* is a holiday or weekend.

Model C3

In addition to estimating the impact of TOU rates on the three experimental groups individually, NCI estimated the weekday demand response impact of TOU rates on the aggregate sample of customers affected using two-way fixed effects. To estimate the overall demand response impact of TOU rates on the weekday on-peak/mid-peak/off-peak consumption of all customers, the following model was estimated:

$$y_{i,t} = \propto_i + \tau_t + DumAll_{i,t} * \beta_1 + \varepsilon_{i,t}$$

Where:

β_1 is the percentage change in *weekday* consumption during on-peak/mid-peak/off-peak hours due to TOU rates for all three experimental groups

$DumAll_{i,t}$ is a dummy variable calculated in the following manner:

$$DumAll_{i,t} = TOU_{i,t} * WorkDay_t$$

Where:

$TOU_{i,t}$ is a dummy equal to one if by day *t* household *i* has switched from tiered to TOU rates and zero otherwise.

$WorkDay_t$ is a dummy equal to one if day *t* is a non-holiday weekday.

All of the rest of the variables for model C3 are defined the same way as they are for model C1.

Model C4

This model follows the same exercise as model C3; it is used to estimate the weekend demand response impact of TOU rates on the aggregate sample of customers affected with two-way fixed effects. The following model was estimated:

$$y_{i,t} = \propto_i + \tau_t + DumAll_{i,t} * \beta_1 + \varepsilon_{i,t}$$

Where:

β_1 is the percentage change in *weekend and holiday* consumption due to TOU rates

$DumAll_{i,t}$ is a dummy variable calculated in the following manner:

$$DumAll_{i,t} = TOU_{i,t} * NonWorkDay_t$$

Where:

$TOU_{i,t}$ is a dummy equal to one if by day *t* household *i* has switched from tiered to TOU rates and zero otherwise.

$NonWorkDay_t$ is a dummy equal to one if day *t* is holiday or weekend and zero otherwise

All of the rest of the variables for model C4 are defined the same way as they are for model C2.

Conservation Effect – Two-way fixed effects

Model D1

To estimate the conservation effect of TOU prices using two-way fixed effects, the following model was estimated:

$$y_{i,t} = \propto_i + \tau_t + Dum27_{i,t} * \beta_1 + Dum28_{i,t} * \beta_2 + Dum29_{i,t} * \beta_3 + \varepsilon_{i,t}$$

Where:

$y_{i,t}$ is the natural logarithm of total consumption for customer *i* during week *t*

$\propto_i$ is the individual household level fixed effect.

τ_t is the day of sample level fixed effect.

$\varepsilon_{i,t}$ is the error for household *i,* in week of sample *t*

β_1, β_2 and β_3 are the percentage change in weekly consumption due to TOU rates for the three experimental groups

$Dum27_{i,t}$, $Dum28_{i,t}$ and $Dum29_{i,t}$ are all dummy variables. These dummies all calculated in the following manner (example for $Dum27_{i,t}$ only):

$$Dum27_{i,t} = Cycle27_i * TOU_t$$

Where:

$Cycle27_i$ is a dummy equal to one if household *i* is in Cycle 27 and zero otherwise

TOU_t is a dummy equal to one if by week *t* that experimental group or cycle has been switched from tiered to TOU rates and zero otherwise

Model D2

As with the demand response impact, in addition to estimating the magnitude of the conservation effect on each individual experimental group, NCI estimated the magnitude of the conservation effect for the aggregate sample of all those on TOU rates. The following model was estimated:

$$y_{i,t} = \propto_i + \tau_t + DumAll_{i,t} * \beta_1 + \varepsilon_{i,t}$$

Where:

β_1 is the percentage change in weekly consumption due to TOU rates

$DumAll_{i,t}$ is a dummy equal to one if by week t household i has been switched from tiered to TOU rates and zero otherwise

All the rest of the variables for model B2 are defined in the same way as for model D1.

Appendix B – Customer Survey

NORTHSTAR
research partners

P09-204

Draft

November 5, 2009

INTRODUCTION

Good morning /afternoon / evening. Could I please speak to **[INSERT CONTACT NAME]**? My name is **[INSERT INTERVIEWER NAME]**, calling from ___________, a national survey and opinion research firm. We are conducting a short survey on behalf of Newmarket Hydro to ask some questions about your electricity use.

[READ ONLY FOR "EXPERIMENTAL" SAMPLE] As a Newmarket Hydro customer subject to (Time-of-use) TOU prices we are interested in your opinions and views on your experiences with the TOU prices to date. Can you spare some time to answer some questions? Thank you.

If respondent asks, you can tell respondents [The survey will take about 18 minutes to complete] otherwise, go ahead with the survey.

Where the acronym TOU appears, read out the full meaning - (Time-of-Use)

SCREENER

S1. Are you the person partially or fully responsible for paying the electricity bill in your household? [**READ. CHECK ONE**]. [NEW]

Yes	☐	
No	☐	**ASK TO SPEAK TO THE PERSON WHO IS RESPONSIBLE FOR PAYING ELECTRICITY BILL [INTRODUCE TO SURVEY FROM BEGINNING). IF NOT AVAILABLE, THANK & ASK FOR AN OPPORTUNE TIME TO REACH THE PERSON RESPONSIBLE.**

AWARENESS OF TIME-OF-USE [TOU] PRICES

1. **[EXPERIMENT SAMPLE]** To begin, does the price of electricity vary depending on the time of day it is used, or do you pay a fixed price regardless of the time of day? [Q4]

   [CONTROL SAMPLE] Up until September of this year, did the price of electricity vary depending on the time of day it was used, or did you pay a fixed price regardless of the time of day? [Q4]

Price varies	❑	
Price is fixed	❑	**[SKIP TO Q10]**
Don't know / not sure	❑	**[SKIP TO Q10]**

As you may already know, time-of-use price is a term used to describe how your electricity prices vary by time of day. This is tracked by smart meters recently installed by Newmarket Hydro that calculate how much electricity you use and when you use it. For the following questions, we would like to focus on your experience with the time-of-use prices.

2. In the order of month then year, can you tell me approximately when you first began paying your electricity bill by time-of-use (TOU) instead of paying the same price all the time? [Q5]

   Month ____________ Year ____________

3. What, if any, information do you recall receiving from Newmarket Hydro about the time-of-use prices? **[READ LIST & SELECT ALL THAT APPLY]** [Q6]

4. Which of those pieces of information was **most** useful to you in understanding time-of-use prices? Please rank them in order of usefulness with "1" being the most useful piece of information, "2" being the second most useful, etc **[READ LIST & RANK]** [Q7]

[RANDOMIZE]

A decal / sticker showing the time-of-use periods	☐		______
A brochure with the answers to frequently asked questions about time-of-use prices and smart meters	☐		______
A conservation brochure with discount coupons for energy saving tools/devices	☐		______
Instructions on how to access smart meter data online	☐		______
Other (please specify): **[PROMPT]** ____________________	☐		______
[DO NOT READ] Don't know	☐	**SKIP TO Q5**	______

[FOR Q5 & Q7 LOOKING AT CHANGES IN PRICE DURING THE DAY, NOT THE PERIODS THAT DETERMINE PRICE CHANGE – SO LOOKING FOR NUMERIC RESPONSES]

5. Thinking about the time-of-use prices, how many times does the price change during a summer weekday (May 1-Oct 31)? **[Please clarify to the respondents that …we want to know how many times the price *changes*, rather than how many price periods there are]** [Q8]

Number of times	________
[DO NOT READ] Don't know	☐

6. What do you recall to be the approximate time for each of the following time periods in the summer (May 1st to October 31st)? **……[READ EACH PERIOD AND CLARIFY WHETHER ITS AM OR PM, INSERT TIME WHERE THERE IS A LINE].** [Q10]

	AM	**PM**
Mid peak period starts (am)	_______	
On-peak period starts	________	________
Mid peak period starts (pm)		________
Off-peak period starts	________	________
Can't remember any times	☐	☐

7. Still thinking about the time-of-use prices, how many times does the price change during a winter weekday (Nov 1-April 30)? **[Please clarify to the respondents that …we want to know how many times the price *changes*, rather than how many price periods there are]** [Q9]

Number of times	________
[DO NOT READ] Don't know	☐

8. What do you recall to be the approximate time for each of the following time periods in the winter (November 1st to April 30th)? **……[READ EACH PERIOD AND CLARIFY WHETHER ITS AM OR PM, INSERT TIME WHERE THERE IS A LINE].** [Q11]

AM **PM**

On-peak period starts (am)	________	
Mid peak period starts (am)	________	
On-peak period starts (pm)	________	________
Mid peak period starts (pm)		________
Off peak period starts	________	________
Can't remember any times	☐	☐

9. Which of the following things have you noticed about the price you pay on your bill since you began paying time-of-use (TOU) prices? **[READ LIST & SELECT ONE ONLY]** [Q12]

You are paying more	☐
You are paying less	☐
You are paying about the same as before	☐
Don't know **[DO NOT READ]**	☐

EVALUATING IMPORTANCE OF TOU PRICES & HOW TO ADAPT TO THEM SUCCESSFULLY

I am going to read you a list of statements about the time-of-use prices initiative in Ontario…

10. Which of the following statements do you think accurately describes why Ontarians are being switched to time-of-use prices? **[SELECT ALL THAT APPLY]** [Q13]

11. Which of the following statements do you think accurately describes **the main reason** why Ontarians are being switched to time-of-use prices? **[SELECT ONE ONLY]** [Q14]

[RANDOMIZE]	**Q10**	**Q11**
To encourage Ontarians to conserve energy	☐	☐
To encourage Ontarians to change the time in which they use electricity	☐	☐
To increase revenue for utilities	☐	☐
Other (please specify): ____________________	☐	☐
None of the above **[DO NOT READ]**	☐	☐
Don't know **[DO NOT READ]**	☐	☐

12. Why do you think Ontarians are being encouraged to conserve energy and / or change when they consume electricity? Is it…**[SELECT ALL THAT APPLY]** [Q15]

[RANDOMIZE]	**YES**	**NO**
To reduce the utilities' costs	☐	☐
To reduce the government's costs	☐	☐
To reduce your electricity costs	☐	☐
To reduce greenhouse gas emissions	☐	☐
To avoid having to build more power plants	☐	☐
Other (please specify): ___________________	☐	☐
None of the above **[DO NOT READ]**	☐	☐
Don't know **[DO NOT READ]**	☐	☐

EVALUATING STRUCTURAL DRIVERS

Next, I am interested in your opinions about energy consumption…

13. Have you heard of the term "conservation culture"? [Q33]

Yes	☐
No	☐

14. On a scale of 1-10 where 1 means 'strongly disagree' and 10 means 'strongly agree' please rate how well the following statements align with your thinking.... [Q34, 35, 36]

[RANDOMIZE]	**Strongly disagree**									**Strongly agree**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
I feel that I have a personal responsibility to help those worse off than me	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
I have enough trouble taking care of myself without worrying about the needs of the worse off	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
I think that I can make an important contribution to reducing the overall use of electricity in the province	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
I feel a moral responsibility to improve the environment for future generations	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑

I feel that my generation has done an unacceptable amount of damage to the environment	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
I believe that climate change is a huge issue that the world must not ignore	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
I'm continuously looking for more ways to lessen my impact on the environment	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑

EVALUATING CUSTOMER ADOPTION TO TOU PRICES

Next, I would like to know your views on some actions that you can take to manage the cost of electricity.

15. How would you rank each of the following actions in terms of the amount of savings that you believe each would provide you? [Q16]

Please rank each action from 1 to 5, where 1 is the action that you feel would provide the highest savings and 5 is the action that you feel would provide the least savings. **[READ LIST, THEN READ AGAIN AND ASSIGN NUMBER]**

[RANDOMIZE]	**[Please insert a number from 1 to 5]**
Vacuuming on a weekend instead of in the late afternoon of a weekday	_____
Using your clothes dryer in the winter after 8 pm (instead of between 5 pm and 8 pm)	_____
Running the dishwasher after 10 pm (instead of between 8 pm and 10 pm	_____
Turning up the temperature on your A/C during the middle of the day. That may mean a slight increase in the temperature of your home.	_____
Ironing clothes on the weekend instead of in the late afternoon on a weekday	_____

16. Next, I would like to understand some of the actions that you would take to help decrease the amount of energy used thereby lowering your electricity bill. How would you rank each of the following actions in terms of savings you believe each would provide you?

Please rank each action from 1 to 5, where 1 is the action that you feel would provide you the highest savings and 5 is the action that you feel would provide you the least savings. **[READ LIST, THEN READ AGAIN AND ASSIGN NUMBER]** [Q17]

[RANDOMIZE]	[Please insert a number from 1 to 5]
Turning your A/C up by two degrees Celsius. **[PLEASE CLARIFY]** That may mean a slight increase in the temperature of your home.	_____
Unplugging consumer electronics when not in use	_____
Using a clothesline to dry your clothing	_____
Replacing your incandescent light bulbs with compact fluorescent light bulbs.	_____
Reducing the number of times per day that you open or close your fridge/freezer	_____

ACCEPTANCE OF IMPORTANCE OF TOU PRICES, SATISFACTION WITH THE INCENTIVES

I am going to read you a list of statements about the time-of-use (TOU) prices and the incentives to redeem your energy use. How strongly do you agree or disagree with each of the following statements. Please use a 10-point scale where 1 means you 'strongly disagree' and 10 means you 'strongly agree'. [Q18, 19, 20]

[RANDOMIZE]	Strongly disagree									Strongly agree
	1	2	3	4	5	6	7	8	9	10
The time-of-use prices are an appropriate way to encourage you to conserve energy and shift demand of electricity	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Being subjected to TOU prices changed the way in which you consume electricity on a day-to-day basis	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
The bill savings you obtained (or could obtain) from changing your electricity consumption habits adequately compensates you for any change in your lifestyle	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑

17. Which of the following household appliances do you have in your home? [NEW + 52]

	YES	NO	
Dishwasher	☐	☐	IF NO TO ALL, SKIP TO Q24
Clothes washer	☐	☐	

Central air-conditioner	☐	☐
Window mounted / room air conditioner	☐	☐
Dehumidifier	☐	☐
Programmable thermostat for your space heat/cooling?	☐	☐

18. **[IF YES TO DISH WASHER AND / OR CLOTHES WASHER AT Q18]** In the **winter** on weekdays, do you regularly (say more than once a week) do any of the following activities between 5 pm and 8 pm? [Q21]

	YES	NO
[IF YES TO DISH WASHER AT Q18] Run your dishwasher	☐	☐
[IF YES TO CLOTHES WASHER AT Q18] Run your clothes washer	☐	☐

19. **[ASK THOSE SAYING YES FOR DISHWASHER AND / OR CLOTHES WASHER AT Q19]** Thinking about the household appliances that you mainly use during winter, if you were offered…[Q22, 24]

	YES	NO	DON'T KNOW [DON'T READ]
[ASK THOSE SAYING YES FOR DISHWASHER AT Q19] \$0.5 per month to use your dishwasher after 8 pm instead of between 5 pm and 8 pm, in the winter, would you do it?	☐	☐	☐
[ASK THOSE SAYING YES FOR CLOTHES WASHER AT Q19] \$1 per month to use your clothes washer after 8 pm instead of between 5 pm and 8 pm in the winter, would you do it?	☐	☐	☐

20. **[IF NO / DON'T KNOW TO DISH WASHER AND / OR CLOTHES WASHER AT Q20]** How much money would you have to be offered per month in order to …[Q23, 25]

[ASK THOSE SAYING NO / DON'T KNOW FOR DISHWASHER AT Q20] Run your dishwasher after 8 pm instead of between 5 pm and 8 pm in the winter	________
ASK THOSE SAYING NO / DON'T KNOW FOR CLOTHES WASHER AT Q20] Use your clothes washer after 8 pm instead of between 5 pm and 8 pm in the winter	________

21. In the **summer** on weekdays, do you regularly (more than once a week) do any of the following between 11 am and 5 pm? [Q26]

	YES	NO
[IF YES TO CENTRAL AIR-CONDITIONER AT Q18] Run central air-conditioner	☐	☐
[IF YES TO WINDOW MOUNTED OR ROOM AIR-CONDITIONER AT Q18] Run a window mounted or room air-conditioner	☐	☐
[IF YES TO DE-HUMIDIFIER AT Q18] Run a de-humidifier	☐	☐

22. **[ASK THOSE SAYING YES FOR AIR-CONDITIONER AND / OR WINDOW MOUNTED OR ROOM AIR-CONDITIONER AND / OR DE-HUMIDIFIER AT Q22]** Thinking about the household appliances that you use mainly during summer time, if you were offered….[Q27, 29, 31]

	YES	NO	DON'T KNOW [DON'T READ]
[ASK THOSE SAYING YES FOR AIR-CONDITIONER AT Q22] $2.75 per year to turn up your central air-conditioner 2 degrees between 11 am to 5 pm in the summer months, **[PLEASE CLARIFY]** That may mean a slight increase in the temperature of your home. Would you do it?	☐	☐	☐
[ASK THOSE SAYING YES FOR WINDOW MOUNTED OR ROOM AIR-CONDITIONER AT Q22] **$**4 per month to run your window air-conditioner from 2 pm to 5 pm instead of from 11 am to 5 pm, would you do it?	☐	☐	☐
[ASK THOSE SAYING YES FOR DE-HUMIDIFIER AT Q22] $2 per month to run your dehumidifier from 2 pm to 5 pm instead of from 11 am to 5 pm, would you do it?	☐	☐	☐

23. **[IF NO / DON'T KNOW TO AIR-CONDITIONER AND / OR WINDOW MOUNTED OR ROOM AIR-CONDITIONER AND / OR DE-HUMIDIFIER AT Q23]**How much money would you have to be offered per month in order to….?[Q28, 30, 32]

Insert an

	amount
[ASK THOSE SAYING NO / DON'T KNOW FOR AIR-CONDITIONER AT Q23] Turn up your central air-conditioner 2 degrees between 11 am to 5 pm? **[PLEASE CLARIFY]** That may mean a slight increase in the temperature of your home.	________
[ASK THOSE SAYING NO / DON'T KNOW FOR WINDOW MOUNTED OR ROOM AIR-CONDITIONER AT Q23] Run your window air-conditioner from 2 pm to 5 pm instead of from 11 am to 5 pm?	________
[ASK THOSE SAYING NO / DON'T KNOW FOR DE-HUMIDIFIER AT Q23] Run your de-humidifier from 2 pm to 5 pm instead of from 11 am to 5 pm?	________

24. **[ASK THOSE WITH A PROGRAMMABLE THERMOSTAT AT Q18]** Thinking about your programmable thermostat…[Q53, 54, 55, 56]

In the summer do you use your programmable thermostat to allow the temperature to rise (i.e. turn up the A/C) when you're not home?	☐	☐
In the summer, do you use your programmable thermostat to allow the temperature to rise (i.e. turn up the A/C) when you're sleeping?	☐	☐
In the winter do you use your programmable thermostat to allow the temperature to fall (i.e. turn down the heat) when you're not home?	☐	☐
In the winter do you use your programmable thermostat to allow the temperature to fall (i.e. turn down the heat) when you're sleeping?	☐	☐

EVALUATING HOUSEHOLD CHANGES

Next, I would like to know about any household changes that may have taken place between December 2007 and July 2009. This will just help us understand how those changes affect electricity consumption since the inception of TOU prices.

25. Has anyone joined (e.g. new roommate / housemate) your household between December 2007 and July 2009? [Q37]

Yes	☐	
No	☐	[SKIP TO 29]

26. **[IF YES AT Q26]** How many people have joined your household since December 2007 and July 2009? _____________ **[INSERT NUMBER]** [Q38]

27. On approximately what month and year did they join your household? [Q38]

NUMBER JOINED	MONTH	YEAR
______________	______________	______________
______________	______________	______________
______________	______________	______________
______________	______________	______________
______________	______________	______________

28. Has anyone left your household (e.g. left for university) between December 2007 and July 2009? [Q39]

Yes	☐	
No	☐	[SKIP TO 32]

29. **[IF YES AT Q29]** How many people have left your household since December 2007 and July 2009? _____________ **[INSERT NUMBER]** [Q40]

30. On approximately what month and year did they leave your household? [Q40]

NUMBER JOINED	MONTH	YEAR
______________	______________	______________
______________	______________	______________

________	________	________
________	________	________
________	________	________

31. **[IF YES AT Q32]** Have any of those that have lived continuously in your household since April, 2007 had their typical daily schedule change significantly between December 2007 and July, 2009 (e.g. finished university and began working, took maternity leave, changed from day to night shift, retired)? [Q41]

Yes	☐	
No	☐	**[SKIP TO Q34]**

32. When (approximately) did these changes occur? [Q42]

NUMBER JOINED	MONTH	YEAR
________	________	________
________	________	________
________	________	________
________	________	________
________	________	________

EVALUATING IN-HOME EQUIPMENT

We are almost done with the survey; I am interested in the kind of fuel you use in your home for some of your household appliances.

33. What type of fuel does your home's **[INSERT EACH PRODUCT LIST BELOW, ONE AT A TIME]** use? [Q47, 48, 49, 50]

		Electric	Other	[DON'T READ] Don't know	N/A
Space heating	☐	☐		☐	☐
Water heater	☐	☐	___________	☐	☐
Stove / Oven	☐	☐	___________	☐	☐
Clothes dryer	☐	☐	___________	☐	☐

34. Do you have an air-conditioner in your home? [NEW]

Yes	☐	
No	☐	[SKIP TO Q37]

35. **[IF YES AT Q35]** What type of air-conditioner if any, do you have? [Q51]

[RANDOMIZE]

Central A/C	☐
Ductless A/C	☐
Window unit	☐
Other	☐
[Don't read] Don't' know	☐
No A/C in home	☐

36. Since December 2007 have you installed or added any major appliances or equipment to your home? [Q54]

Yes	☐	
No	☐	**[SKIP TO Q40]**

37. **[IF YES AT Q37]** Which of the following have you added or replaced since December 2007? [Q55]

Refrigerator	☐	☐
Freezer	☐	☐
Clothes washer	☐	☐
Clothes dryer (electric)	☐	☐
Dishwasher	☐	☐
Ceiling /attic /wall /basement insulation	☐	☐
Replaced windows	☐	☐
Weatherproofed home	☐	☐
Air-conditioner	☐	☐
Programmable thermostat	☐	☐

38. How much did being on TOU prices help you decide on one **[INSERT EACH PRODUCT AT Q 34]** model over another? For example paying a little more for a dishwasher with a delay switch, or an appliance with Energy Star

certification. Please use a scale of 1 to 10 where 1 means didn't influence my decision at all and 10 means entirely directed my decision. [Q55]

[ASK FOR EACH PRODUCT SELECTED AT Q 38]	Didn't influence my decision at all								Entirely directed my decision
	1	2	3	4	5	6	7	8	9	10
Refrigerator	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Freezer	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Clothes washer	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Clothes dryer (electric)	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Dishwasher	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Ceiling /attic /wall /basement insulation	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Replaced windows	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Weatherproofed home	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Air-conditioner	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Programmable thermostat	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑

39. Between December 2007 and July 2009 did you dispose of *and not replace* any major appliances or electronic equipment (e.g. a big-screen TV, chest freezer, second fridge)? [Q43]

Yes	☐	
No	☐	**[SKIP TO Q42]**

40. **[IF YES AT Q40]** Approximately, what month and year did you dispose each item that you didn't replace? [Q43]

	MONTH	YEAR
____________	____________	____________
____________	____________	____________
____________	____________	____________
____________	____________	____________

41. Between December 2007 and July 2009 did you acquire any major appliances or electronic equipment that *did not replace* a similar item you already owned / operated in your home (e.g. a pooler, chest freezer, air conditioner)? [Q44]

Yes	☐	
No	☐	**[SKIP TO Q44]**

42. **[IF YES AT Q42]** Approximately, what month and year did you acquire each item that you didn't replace? [Q44]

	MONTH	YEAR
________	________	________
________	________	________
________	________	________
________	________	________
________	________	________

43. Between December 2007 and July 2009 did you replace….? Q45, 46]

	YES	NO	NOT APPLICABLE	
Your electric water heater with a natural-gas water heater	☐	☐	☐	**IF NO AND/ OR NOT APPLICABLE FOR BOTH ITEMS SKIP TO Q46**
Your electric furnace with a natural gas furnace	☐	☐	☐	

44. **[ASK FOR EACH PRODUCT SAID "YES" AT Q44]** Approximately, what month and year did you make this change? Q45, 46]

	MONTH	YEAR
Replace electric water heater with natural gas water heater	________	________
Replace electric Furnace with natural gas furnace	________	________

45. Between December 2007 and July 2009 did you replace your natural gas water heater or furnace with an electric water heater or furnace? Q45, 46]

	YES	NO	NOT APPLICABLE	
Your natural-gas water heater with an electric water heater	☐	☐	☐	**IF NO AND/ OR NOT APPLICABLE FOR BOTH ITEMS SKIP TO Q48**
Your natural-gas furnace with an electric furnace	☐	☐	☐	

46. **[ASK FOR EACH PRODUCT SAID "YES" AT Q46]** Approximately, what month and year did you make this change Q45, 46]

	MONTH	YEAR
Replace natural-gas water heater with electric water heater	________	________
Replace natural-gas furnace with electric furnace	________	________

47. Since December 2007, have you begun to practice any of the following general energy saving actions? Q56]

Turned up thermostat setting in summer (turned up A/C)	☐	☐
Turned down thermostat setting in winter (turned down heat)	☐	☐
Closed drapes during the day to block the sun	☐	☐
Used air conditioning less frequently and for less time	☐	☐

Washed clothing in cold water	☐	☐
Dried clothes on hanger/line not in dryer	☐	☐
Reduced clothes washing during peak periods	☐	☐
Turned off/reduced use of lights in peak periods	☐	☐
Turned down heat (electric) during peak hours	☐	☐
Other (please specify) ___________________________	☐	☐

48. How likely were you to take any of the following actions if you had not been on TOU prices? Please use a scale from 1 to 10 where 1 means not at all likely and 10 means extremely likely. Q56]

[ASK FOR EACH STATEMENT WITH A YES AT Q48]	**Not at all likely**									**Extremely likely**
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Turned up thermostat setting in summer (turned up A/C)	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Turned down thermostat setting in winter (turned down heat)	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Closed drapes during the day to block the sun	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Used air conditioning less frequently and for less time	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Washed clothing in cold water	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Dried clothes on hanger/line not in dryer	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Reduced clothes washing during peak periods	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Turned off/reduced use of lights in peak periods	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Turned down heat (electric) during peak hours	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
Other (please specify) ___________________________	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑

49. Which of the following energy-conservation or demand reduction programs are you participating in…? Q57]

[RANDOMIZE]

Every Kilowatt Counts coupon program. This program offers customers coupons for compact fluorescent	☐	☐

lights, outdoor solar lights, LED Christmas lights and other energy saving products		
Summer Savings or Summer Sweepstakes programs. This program offers customers a 10% bill credit for reducing their summer electricity consumption by 10%.	☐	☐
Great Refrigerator Round-Up/fridge pick-up and recycling program. This program offers free pickup (disposal) of fridges and freezers 15 years or older and window air-conditioners and dehumidifiers 10 years or older.	☐	☐
Hot/Cool Savings Program. This program offers a rebate when customers replace old thermostats, furnaces or CAC units.	☐	☐
EcoEnergy Retrofit Program. This federal program offers grants for homeowners who wish to retrofit their homes to improve energy efficiency.	☐	☐
Peaksaver program. This program offers a $25 honorarium to customers who allow their utility to remotely reduce the amount of power that the customer's air conditioner is using.	☐	☐
[PROMPT] Other (please specify) ___________________________	☐	☐

DEMOGRAPHICS

And finally, a few questions for data classification. This information is strictly confidential.

51. Do you rent or own your home? Q57]

Own	☐
Rent	☐

52. Do you receive a bill from Newmarket Hydro? [Q58]

Yes	☐
No	☐

53. How many people in your household are regularly (three or more days) at home during working hours on weekdays? Q59]

____

54. What are their ages? **[INSERT AGE FOR EACH PERSON]** Q60]

____

____

____

55. What is the highest level of education completed by any member of your household? Q61]

Public or elementary school	❑

High school ❑

College / technical or trade school ❑

University ❑

Post-graduate (Master's, PhD) ❑

56. What type of building do you live in? Q62]

Fully-detached house ❑

Semi-detached house ❑

Townhouse (attached on two sides) ❑

Apartment building less than 5 stories ❑

Apartment building over 5 stories ❑

57. In approximately what year was your home built? Q63]

2000 or later ❑

1980 - 1999 ❑

1960 – 1979 ❑

Before 1960 ❑

[Don't read] Don't know ❑

(s)

Thank you very much for sharing your feedback. Your answers and opinions will be very helpful.

PASS-THROUGH CHARGES

	US of A	2006	2007	2008 Actual	2009 Actual	2010 Test
Cost of Power						
Power Purchased	4705	42,645,650	43,047,462	42,780,154	43,453,995	44,394,543
Charges - WMS	4708	3,823,944	3,798,160	4,344,774	4,335,340	4,643,033
One Time	4712	32,335	142,697	(13,476)	19,547	0
Charges - NW	4714	4,299,419	4,207,506	3,716,799	3,552,823	4,525,660
Charges - CN	4716	3,558,373	3,553,518	3,207,201	3,175,485	3,368,696
Total COP		**54,359,722**	**54,749,344**	**54,035,453**	**54,537,190**	**56,931,933**

Cost of Power Details

The Cost of Power has been calculated by multiplying the retail kWh sales by the historical average load factor to get wholesale kWh's and then applying supplied wholesale rates.

Retail kWh

Retail kWh are described in detail in Exhibit 3.

Wholesale kWh

Calculated by applying the average loss factor of 1.0356 (Exhibit 8 – Rate Design) to the projected Retail kWh sales.

Energy Component (Commodity)

The April 1, 2009 RPP rate of $62.15/mWh as provided by the Ontario Energy Board was applied to the retail mWh sales.

One-Time Charges

These debits/credits are difficult to predict and relatively small by comparison to the other components. Therefore the estimate is assumed to be $0..

Wholesale Market Services (WMS) & Rural Rate Assistance (RRA)

This estimate assumes that the retail rates for these charges to our customers are a proxy for the wholesale costs. Therefore the estimate is based on $.0052 for WMS + $.0013 for RRA = $.0065/ kWh x Wholesale kWh’s.

Transmission – Network and Connection

The 2010 estimates were based on the Wholesale Rates being billed by the IESO. 2008 was billed at a single rate for the year and therefore provides a good basis for estimating future costs. Therefore the 2008 actual costs were adjusted by the percentage change in kWh for both 2009 and 2010 and then adjusted by the percentage change in rates for both years.

The following table provides the details for the calculations:

Detailed Cost of Power Calculations

	2008 Actual	2009 Actual	2010 Estimate
Wholesale kWh			
Retail kWh Sales (from Rate Model)	742,274,340	700,600,681	689,773,632
Loss Factor (from Rate Model)		1.0356	1.0356
Total	754,258,226	725,525,075	714,312,845
Commodity			
Wholesale Rate (OEB RPP Apr 1/09)		0.06072	0.06215
Wholesale Commodity Cost	42,780,154	43,453,995	44,394,543
Wholesale Market Services			
WMS Rate			0.0052
Rural Rate Protection/kWh			0.0013

Combined Rate			0.0065
WMS Cost	4,344,774	4,335,340	4,643,033
One Time Costs	(13,476)	19,547	0
Wholesale Transmission Network			
Rate/kW	2.31		2.97
Rate change factor - 2008 to 2010			1.2857
kWh change factor - 2008 to 2010			0.9470
Transmission Network Cost	3,716,799	3,552,823	4,525,660
Wholesale Transmission Connection			
Rate/kW	2.20		2.44
Rate change factor - 2008 to 2010			1.1091
kWh change factor - 2008 to 2010			0.9470
Transmission Connection Cost	3,207,201	3,175,485	3,368,696
Total Cost of Power	**54,035,453**	**54,537,190**	**56,931,933**

1

Exhibit 3: Revenue

Tab 2 (of 3): Distribution Revenue

OVERVIEW OF DISTRIBUTION REVENUE

This exhibit provides detailed calculations and variance analysis of the Distribution Revenue components by rate class. The Applicant has presented its actual results for 2007, 2008, 2009 and estimated amounts for 2010 in a summary table shown below. As noted in the overview to this chapter the 2010 projected distribution revenues are based upon the consumption forecasts as determined by Elenchus with no adjustment for TOU pricing in the residential class. The distribution revenue is presented on a consolidated basis. The Applicant has complied distribution revenue by service area and consolidated these results to provide a total revenue from all customers. Distribution Revenues do not include commodity revenues or rate rider/adders. All customer counts are based on the average for the year. Consumption (kWh) and Demand (kW) values are weather normalized as determined in the Elenchus report “Weather Normalized Distribution System Load Forecast – 2010 Test Year”

	2007	2008	2009 Bridge (12 mons @ 2009 rates)	2010 Test (12 mons @ 2009 Rates)	2010 Test (12 mons @ 2010 Rates)
Residential	7,996,556	8,104,474	8,315,769	8,415,172	9,926,666
GS<50	2,348,127	2,361,827	2,361,373	2,373,704	2,792,019
USL	29,702	29,951	25,033	25,033	29,445
GS>50	4,164,664	4,214,383	3,844,240	3,730,931	4,388,428
Street Lights	60,346	61,738	288,727	292,715	315,800
Sentinel Lights	12,035	12,035	14,597	14,038	16,508
Total	$14,611,430	$14,784,408	$ 14,849,739	$14,851,593	$ 17,468,866

REVENUE ANALYSIS BY CLASS

Residential

The table below provides the derivation of the fixed and variable revenue recovered through authorized distribution rates from the Residential customer class for 2007, 2008, 2009 and 2010TY.

	2007	2008	2009	2010 Test (12 mons @ 2009 rates)	2010 Test (12 mons @ 2010 rates)
Residential					
Average Customers (ERA rpt pg 13)	27,595	28,147	28,852	29,370	29,370
Fixed Charge Revenue ($)	4,473,225	4,561,990	4,705,994	4,789,786	5,991,480
kWh/Customer (ERA rpt pg 14)	9,751	9,616	9,485	9,358	9,358
Total kWh (ERA rpt pg 13)	269,084,727	270,664,123	273,677,263	274,854,374	274,854,374
Variable Charge Revenue ($)	3,523,330	3,542,483	3,609,775	3,625,386	3,935,186
Total ($)	7,996,556	8,104,474	8,315,769	8,415,172	9,926,666
Fixed Charge Component	56%	56%	57%	57%	60%

Customer Trend Table

The following table provides a six year trend of customers and connections served by The Applicant. It shows that, on average, The Applicant connects 560 new residential customers per year. Note that these values are based on year end counts in order to provide actual and projected customer additions for that particular year.

Residential						
	Newmarket		Tay		NT Power	
Year	**Year End Count**	**Additions**	**Year End Count**	**Additions**	**Year End Count**	**Additions**
2005	23,118	433	3,700	46	26,818	479
2006	23,647	529	3,758	58	27,405	587
2007	24,069	422	3,793	35	27,862	457
2008	24,667	598	3,817	24	28,484	622
2009	25,311	644	3,827	10	29,138	654
Average		**525.2**		**34.6**		**559.8**
2010	25,749	438	3,853	26	29,602	464

Elenchus forecasts that the increase in customers in the residential class will be 464 in 2010. This is 190 less than the number connected during the 2009, but only 96 less than the five year average. The decrease in connections can be attributed to:

- the continuation of the economic downturn that began in 2008;
- accelerated developer sales in 2009 and reduction in sales activity in 2010.

The Applicant’s data shows that in a typical year, it connects approximately 560 new residential customers. This is reflected by the average annual number of residential customer connections in the 2005-2009 period. The Applicant notes that residential customer connections in 2008 and 2009 are somewhat higher than average and attributes this to developers accelerated sales activity and the completion of developments already underway prior to the downturn.

The Applicant examined its Offers to Connect made to developers. This examination shows that developers are requesting fewer Offers to Connect and that the requested Offers to Connect are lagging behind in the number of connections being made vs. the numbers forecast in the offer. There are currently less than 1,000 outstanding connections within the existing Offers to Connect. The Applicant has only had one new Offer to Connect since December 2008 and that Offer is for only 13 homes.

Analysis of Changes in Consumption and Variable Revenues

The Applicant's average residential customer is forecast to consume fewer kWh in the 2010TY versus the 2008HY. This reduction reflects the impact of a) CDM achievements

a) customer's changing responses to the environment and current economic conditions,

b) longer term and ongoing changes in the types of housing stock built and appliances used. The Applicant has observed that, when comparing homes constructed 40-50 years ago, newly constructed homes are typically:

- more energy efficient structures due to changes in construction standards and building code requirements; and
- exclusively natural gas fueled space and water heating appliances.

Each of these factors contributes to reduced electricity consumption in the residential customer class.

The Applicant's residential customer class on average has exhibited a decrease average consumption over the 2006-2010 periods. The information presented is the weather normalized average consumption as presented by Elenchus in their load forecast report.

	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Residential kWh/Year	9,770	9,751	9,616	9,485	9,358

General Service <50 kW

The table below provides the derivation of the fixed and variable revenue recovered through authorized distribution rates from the GS<50 customer class for 2007, 2008, 2009 and 2010.

	2007	2008	2009 Bridge (12 mons @ 2009 rates)	2010 Test (12 mons @ 2009 rates)	2010 Test (12 mons @ 2010 rates)
General Service Less Than 50 kW					
Average Customers (ERA rpt pg 13)	2,791	2,843	2,881	2,901	2,901
Fixed Charge Revenue ($)	685,644	698,492	842,606	848,324	1,148,796
kWh/Customer (ERA rpt pg 14)	34,825	34,208	33,096	33,012	33,012
Total kWh (ERA rpt pg 13)	97,191,291	97,259,917	95,338,741	95,754,008	95,754,008
Variable Charge Revenue ($)	1,662,484	1,663,336	1,518,767	1,525,380	1,643,223
Total ($)	2,348,127	2,361,827	2,361,373	2,373,704	2,792,019
Fixed Charge Component	29%	30%	36%	36%	41%

<u>Analysis of Variances in Number of Customers and Fixed Rate Revenues</u>

The following table provides a five-year trend of actual customers and connections and a one-year forecast for 2010. It shows that, on average, The Applicant connects 21 new small commercial customers a year.

GS<50 kW						
	Newmarket		Tay		NT Power	
Year	**Year End Count**	**Additions**	**Year End Count**	**Additions**	**Year End Count**	**Additions**
2005	2,548	-27	214	2	2,762	-25
2006	2,557	9	212	-2	2,769	7
2007	2,599	42	216	4	2,815	46
2008	2,653	54	217	1	2,870	55
2009	2,671	18	222	5	2,893	23
Average		**19.2**		**2**		**21.2**
2010	2,681	10	228	6	2,909	16

The GS<50 kW customer class includes retailers and light industrial customers. The Applicant expects to connect 16 new GS<50 kW customers in 2010. This is down from the 23 customers that were attached in the 2009, but this lower increase correlates with the computed reduction in the number of newly connected residential customers. The Applicant expects new commercial development will continue to lag behind the recovery of the large general service class and residential development due to the current economic downturn.

The high number of new GS<50 kW customers connected in 2007 and 2008 is due to the commissioning of two non-bulk metered large scale strip malls, one in 2007 and the other in 2008. The Applicant has not had any larger strip malls connected since then nor has it received any notification of large strip malls being planned. The decrease of customers in 2005 is the result of the reclassification of customers from the GS<50 kW class to GS>50 kW class.

Analysis of Changes in Consumption and Variable Revenues

The Applicant's GS<50 kW customer class on average has exhibited stable average consumption over the 2006-2010 period. The majority of these customers use electricity as base load (e.g. for lighting and appliances) and for light manufacturing processes.

NT Power	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
GS<50 kWh / Year	33,874	34,825	34,208	33,096	33,012

The Applicant has participated in the OPA programs designed for this customer class which have been targeted to lighting retrofits. The associated CDM achievements in The Applicant's service areas are documented in the CDM reports previously filed the board. The quantified savings amount to approximately 200,000 kWh, or about 0.2% of total energy delivered to these customers.

General Service >50 kW

The table below provides the derivation of the fixed and variable revenues recovered through authorized distribution rates from the GS >50 kW customer class for 2007, 2008 and 2009 and forecast for the 2010TY.

	2007	2008	2009 Bridge (12 mons @ 2009 rates)	2010 Test (12 mons @ 2009 rates)	2010 Test (12 mons @ 2010 rates)
General Service 50 to 4,999 kW					
Average Customers (ERA rpt pg 13)	385	395	398	401	401
Fixed Charge Revenue ($)	1,708,184	1,749,307	759,873	765,526	721,800
kWh/Customer (ERA rpt pg 14)	941,242	932,825	818,072	780,829	780,829
Total kWh (ERA rpt pg 13)	362,378,335	368,466,063	325,592,529	313,112,560	313,112,560
kW/Customer	2,273	2,219	2,060	1,966	1,966
Total kW (ERA rpt pg 13)	875,286	876,623	819,940	788,495	788,495
kW Transformer Allowance	690,854	680,227	625,544	601,285	601,285
Variable Charge Revenue ($)	2,802,176	2,805,571	3,521,842	3,385,897	4,087,527
Variable Charge Revenue Trans Allowance($)	(345,696)	(340,495)	(437,475)	(420,492)	(420,900)
Total ($)	4,164,664	4,214,383	3,844,240	3,730,931	4,388,428
Fixed Charge Component	41%	42%	20%	21%	16%

The Applicant forecasts that it will add three incremental GS>50 kW customers in 2010. The GS>50 kW customer class includes industrial manufacturers – many of whom are engaged in automobile parts assembly and or fabrication – as well as large retail and institutional customers. In 2008 the billed demand for GS>50 kW customer class amounted to 876,623 kW of which over 15% was billed to end users engaged in auto parts fabrication or assembly. For the 2010 forecast the number of GS>50 kW customers is subject to greater risk because of the continuing restructuring of the automotive sector.

Analysis of Variances in Number of Customers and Fixed Rate Revenues

The following table provides a five-year trend of customers and connections served by the Applicant. It shows that, on average that The Applicant connects 6 new GS>50customers per year using the period 2006 to 2008 as a guide. As mentioned above, 2005 is misleading due to customer reclassifications from the GS<50 kW class.

GS>50 kW						
	Newmarket		Tay		NT Power	
Year	Year End Count	Additions	Year End Count	Additions	Year End Count	Additions
2005	365	49	11	2	376	51
2006	368	3	14	3	382	6
2007	374	6	17	3	391	9
2008	377	3	17	0	394	3
2009	383	6	15	-2	398	4
Average		**13.40**		**1.20**		**14.60**
2010	387	4	17	2	404	6

There is a considerable decrease in the Fixed Charge Revenue between 2008 and 2009 and then a lesser one 2009 to 2010. This is a result of the cost of service rates used for both of these periods.

In 2009 The Applicant lost one Magna plant (RimPly), its largest customer and three other large-use customers. RimPly and 2 others were engaged in auto parts manufacturing and fabricating. Only one of these sites is currently operational and under reduced load. The other plants are currently dormant and neither The Applicant nor the Town of Newmarket economic development office is aware of any activity planned for them. There has been no sale of these properties/facilities and no formal plans announced to use these properties for alternative purposes. Until any plans for these properties are confirmed, The Applicant will continue to provide distribution service to these sites and to classify the sites as GS>50 customers but at much reduced loads.

The loss of these customers has reduced The Applicant's distribution revenue by $380,000 per year.

Analysis of Changes in Consumption and Variable Rate Revenues

The following table shows that The Applicant's GS>50 kW customers have experienced and will continue to experience a significant reduction in average demand. Demand has decreased from 2,346 kW in 2006 to a projected 1,966 kW in the 2010TY or a 16.2% reduction. This average decline reflects the loss of a total of about 89,000 kW in the same period, and is primarily due to the loss of the Applicant's automotive customers.

NT Power	**2006 Actual**	**2007 Actual**	**2008 Actual**	**2009 Bridge**	**2010 Test**
GS>50 kW / Year	2,346	2,273	2,219	2,060	1,966

Other Rate Classes

Street Lighting Class

The table below provides the derivation of the fixed and variable revenue recovered through authorized distribution rates from the Street Lighting class for 2007, 2008 and2009 and the forecast for 2010TY.

	2007	2008	2009 Bridge (12 mons @ 2009 rates)	2010 Test (12 mons @ 2009 rates)	2010 Test (12 mons @ 2010 rates)
Street Lighting					
Connections	8,023	8,208	8,463	8,574	8,574
Fixed Charge Revenue ($)	33,269	33,961	169,596	171,941	205,776
Metered KWh	4,944,311	5,167,674	5,286,191	5,355,339	5,355,339
Metered KW	13,652	14,040	14,394	14,582	14,582
Variable Charge Revenue ($)	27,078	27,777	119,131	120,774	110,024
Total ($)	60,346	61,738	288,727	292,715	315,800
Fixed Charge Component	55%	55%	59%	59%	65%

Analysis of changes in Fixed and Variable Rate Revenues

Forecast new connections closely follow the rate of new connections within the Residential Class. The most significant change is the result of the cost of service rates that were approved for the Newmarket service territory for 2009. The Tay service territory has not had a rate change based on cost of service before this application.

Sentinel Lighting

The table below provides the derivation of the fixed and variable revenue recovered through authorized distribution rates from the Sentinel Lighting class for 2007, 2008 and 2009 and the forecast for 2010TY.

	2007	2008	2009 Bridge (12 mons @ 2009 rates)	2010 Test (12 mons @ 2009 rates)	2010 Test (12 mons @ 2010 rates)
Sentinel Lighting					
Connections	444	444	426	407	407
Fixed Charge Revenue ($)	9,077	9,077	8,822	8,421	9,768
Metered KWh	319,360	318,972	314,839	306,233	306,233
Metered KW	969	969	874	850	850
Variable Charge Revenue ($)	2,958	2,958	5,775	5,617	6,740
Total ($)	12,035	12,035	14,597	14,038	16,508
Fixed Charge Component	75%	75%	60%	60%	59%

Analysis of changes in Fixed and Variable Rate Revenues

The most significant change is the result of the cost of service rates that were approved for the Newmarket service territory for 2009. The Tay service territory has not had a rate change based on cost of service before this application.

Unmetered Scattered Load

The table below provides the derivation of the fixed and variable revenue recovered through authorized distribution rates from the Unmetered Scattered Load class for 2007, 2008 and 2009 and the forecast for 2010TY.

	2007	2008	2009 Bridge (12 mons @ 2009 rates)	2010 Test (12 mons @ 2009 rates)	2010 Test (12 mons @ 2010 rates)
Unmetered Scattered Load					
Customers	129	125	125	125	125
Fixed Charge Revenue ($)	23,617	23,265	19,161	19,161	18,000
Metered KWh	360,984	397,591	391,118	391,118	391,118
Variable Charge Revenue ($)	6,084	6,686	5,872	5,872	11,445
Total ($)	29,702	29,951	25,033	25,033	29,445
Fixed Charge Component	80%	78%	77%	77%	61%

Analysis of changes in Fixed and Variable Rate Revenues

There is little impact on this class due to The Applicant's policy to meter as many connections as possible. Therefore consumption and connection levels will remain the same in 2010 TY as the 2009 actual values.

Exhibit 3: Revenue

Tab 3 (of 3): Other Revenue

OVERVIEW OF OTHER REVENUE

The Applicant proposes to recover $846,361 in other revenues for the 2010 test year. At The Applicant's current rates for specific service charges and forecasted 2010 quantities, the Applicant would collect only $798,781. In the Newmarket service area The Applicant is still charging its original specific service charges. The reason for this is that the Newmarket service area was not part of the 2006 EDR. In this proceeding, The Applicant is seeking to implement the rates established by the 2006 EDR with three exceptions:

1) Account Set up Charge

2) Collection of Account Charges with no disconnection

3) Disconnect Reconnect at Meter during regular hours

These are shown in the following "Other Revenues" chart along with the details of The Applicant's forecasted Other Distribution Revenues on a consolidated basis. The consolidated basis amounts were derived by applying requested rates by projected quantities in each service territory and adding them together.

The Applicant's consolidated other revenue has decreased from $1,366,716 in 2006 to $1,003,479 in 2008 to a projected $798,781 (using current specific service charges) in 2010.

The majority of the decrease in other revenues can be attributed to the decrease in interest revenue which was recorded at $541,549 in 2006 and is projected to be zero in 2010. This decrease is due to the following reasons:

- A significant amount of cash flow has been spent on capital programs. In the four year period from 2006 to 2009 The Applicant has increased net fixed assets by over $9 million (including over $5 million on smart meters and TOU billing the majority of which The Applicant funded from its own cash flows).

- Interest rates are at historical low. The Applicant achieves an interest rate of Canadian Business prime less 1.75 (0.5%) on outstanding cash balances (it pays Canadian Business Prime on customer deposits).

When comparing total 2009 other revenues to the 2010 forecast there is a $131,121 decrease. The difference is principally due to decreases in interest earnings of $88,647 and late payment charges of $20,034. Exhibit 03, Table 04, Schedule 01, Attachment 01 below summarizes the other revenues since 2006 and the projected 2010TY revenues.

REVENUE OFFSETS

Account Name	US of A	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Test (Current Rates)	2010 Test (Proposed Rates)
SSS Administration Charge	4080	103,982	103,280	106,178	107,998	111,441	111,441
Retail Service Revenues	4082	36,369	41,037	47,714	47,085	46,950	46,950
STR Revenues	4084	1,957	8,940	1,511	4,249	1,565	1,565
Revenue-Rentals	4210	131,876	114,523	120,510	124,227	120,510	120,510
Revenue-Late Payment Charges	4225	181,944	190,666	181,345	214,538	194,504	194,504
Specific Service Charges	4235	302,730	280,849	325,108	319,007	319,016	366,596
Revenue-Sale of Scrap Metals	4325	20,464	17,115	10,795	11,490	4,795	4,795
Gain on Disposition of Utility and Other Properties	4355	49,898	8,372	750	0	0	0
Loss on Disposition of Utility and Other Properties	4360	(133)	0	0	(995)	0	0
Revenue-Miscellaneous	4390	(3,921)	45,230	26,784	13,656	0	0
Interest Earned	4405	541,549	461,056	182,785	88,647	0	0
Grand Total Other Revenue		**1,366,716**	**1,271,067**	**1,003,479**	**929,902**	**798,781**	**846,361**

<u>SSS Administration Charge</u> - Consolidated forecasted amount of $111,441

In accordance with the Retail Settlement Code, The Applicant must provide standard supply service to any customer connected to its distribution system, unless the person has enrolled with a retailer. The Applicant is allowed to charge an administrative charge of $0.25 per customer/connection per month to these standard supply customers.

Retail Service Revenue - Consolidated forecasted amount $46,950.

The Applicant is requesting approval to collect $46,950 in retail service charges from electricity retailers to cover the cost of managing and billing retailer customers. All charges are in accordance with the Retail Settlement Code. The charges are as follows:

i. A monthly fixed charge of $20 per month, per retailer

15 retailers at $20 per month = $3,600

plus

ii. The monthly variable charge of $0.50, per month, per customer and a retailer distributor consolidated billing charge of $.30per customer per month

Revenue – Rentals - Consolidated forecasted amount of $120,510

“Revenue-Rentals” consists solely of pole rentals. The Applicant is party to several joint-use agreements with Hydro One Networks Inc. (HONI), Bell Canada, and other various local cable companies. The Applicant’s shareholder has no attachments on the poles.

Late Payment Charges - Consolidated forecasted amount of $194,504

The Applicant expects the revenue generated from late payment charges to increase from $181,345 in 2008 to $194,504 in 2010. This is a decrease from the level in 2009 level of $214,538 which The Applicant believes was abnormally high due to the severe economic conditions. The overall increase between2008 and 2010 is due equally to customer growth; the current economic climate and potentially higher bills as the result of the increased cost of power and the introduction of the HST. In 2009, The Applicant has observed a significant increase in delinquent payments which have resulted in higher late payment penalties. Thus for 2010 The Applicant is encouraging customers to enroll in the Pre Authorized Payment Program to help them avoid being charged late payment penalties on a regular basis.

SPECIFIC SERVICE CHARGES

The Applicant has harmonized its revenue recovered through SSC's by applying the currently authorized rates in each service area to the forecasted quantities for each service area and summing the results.

The following tables show the SSC revenues at existing rates:

Specific Service Charges

Description	2006 Actual		2007 Actual		2008 Actual		2009 Actual		2010 Test at existing rates	
	#	$	#	$	#	$	#	$	#	$
Arrears certificate	55	468	53	451	228	2,290	242	2,409	184	1,833
Statement of account	39	332	42	357	254	2,523	259	2,567	197	1,953
Duplicate invoices for previous billing	33	107	21	68	47	282	48	284	37	216
Request for other billing information	23	0	18	0	6	90	6	90	6	91
Easement letter	31	264	35	298	255	2,530	260	2,575	264	2,613
Account history	31	264	25	213	0	0	0	0	0	0
Credit reference/credit check (plus credit agency costs)	804	8,040	603	6,030	965	10,670	959	10,487	951	10,501
Returned cheque charge (plus bank charges)	825	13,613	850	14,025	1,020	16,496	1,035	16,754	1,052	17,033
Legal letter charge	45	0	38	0	0	0	0	0	0	0
Change of Occupancy - Final Bill	3,703	46,288	3,463	43,288	3,451	43,138	3,362	42,025	3,252	40,649
Account set up charge (plus credit agency costs if applicable)	3,702	46,275	3,170	39,625	4,565	63,765	4,457	59,440	4,339	58,339
Special meter reads	6	0	6	0	0	0	0	0	0	0
Collection of account charge - no disconnection	8,183	146,338	7,094	125,755	7,676	149,750	7,591	148,214	7,737	151,061
Disconnect/Reconnect at meter - during regular hours	186	6,117	238	8,229	558	29,365	568	29,857	578	30,369
Disconnect/Reconnect at meter - after regular hours	14	1,680	10	1,200	34	4,210	35	4,303	35	4,358
Disconnect/Reconnect at pole - during regular hours	0	160	0	0	0	0	0	0	0	0
Disconnect/Reconnect at pole - after regular hours	0	315	0	0	0	0	0	0	0	0
Meter dispute test self contained plus Measurement Canada fees (if meter found correct)	0	250	0	0	0	0	0	0	0	0
Service call - customer-owned equipment	0	0	0	0	0	0	0	0	0	0
Service call - after regular hours	0	0	0	0	0	0	0	0	0	0
Total SSC's		**270,509**		**239,537**		**325,107**		**319,007**		**319,016**

For 2006-2009 quantities listed in the table above are based on actual amounts incurred. In 2010 for the following categories:

- Collection of account charge - no disconnection
- Disconnect/Reconnect at meter - during regular hours
- Disconnect/Reconnect at meter - after regular hours
- Returned cheque charge (plus bank charges)
- Easement letter

The projected quantities were derived by the Applicant taking the 2009 actual quantities incurred and adjusted those quantities by the growth in new residential connections as indicated by the Elenchus Load forecast of 1.8 %.

In 2010 for the following categories:

- Arrears certificate
- Statement of account
- Duplicate invoices for previous billing

The projected quantities were derived by the Applicant taking the 2009 actual quantities incurred and adjusted the quantities by the growth in new residential connections as indicated by the Elenchus Load forecast of 1.8 %. Then the Applicant discounted this amount by 25%. The Applicant assumed that since residential customers are currently paying less than ½ of the proposed amounts and these statements are available on-line, that there would be a significant reduction in usage.

In 2010 for the following categories:

- Credit reference/credit check (plus credit agency costs)
- Change of Occupancy - Final Bill
- Account set up charge (plus credit agency costs if applicable)

The projected quantities were derived by the Applicant taking the 2009 actual quantities incurred and adjusted the quantities by the growth in new residential connections as indicated by the Elenchus Load forecast of 1.8 %. Then the Applicant discounted this amount by 5%. The Applicant assumed that since housing prices had decreased, there would be a small reduction in people moving houses, thus a reduction in change in occupancy charges and reference checks.

Specific Service Charges – Non-Standard Rates

In Exhibit 3, Tab 3, Schedule 4, The Applicant's existing Specific Service Charges ("SSC") rates will yield $319,016 of revenue in the 2010TY. The Applicant is requesting a change in the SSC's on two bases:

1) The Applicant is currently charging two different sets of SSC's. In the Tay service area, the rates are based on the standard rates that were approved with the 2006 EDR. In the Newmarket service area The Applicant declined to participate in the 2006 EDR process and therefore its SSC rates have remained unchanged since its original1999 levels.

2) The Applicant is requesting that both service areas charge the OEB SSC's as outlined in the 2006 EDR process with the exception of three service charges (listed below)

- Account Setup Charge (Plus Credit Agency Costs if Applicable)
- Collection of Account Charge – No Disconnection
- Disconnect Reconnect at Meter During Regular Hours

With each of the above three services, The Applicant contracts the field visit through third party providers at reduced costs. The Applicant used the model developed for the 2006 EDR to calculate rates that include the contract cost rather than the LDC Labour cost of the field visit. The following tables show these calculations:

1

Non-Standard Rates

Generic Rates and Model for Deriving LDC Specific Rates				
LDC Name:	***Newmarket-Tay Power Distribution Ltd. - Newmarket***			
Fill in only the blue ranges that are appropriate for the Specific Service Charge Described.				
SSC Description:	**Account set up charge (plus credit agency costs if applicable)**			
		Rate	**Hours or Units**	**Calculated Cost**
Labour	Direct Labour (inside staff) Straight Time	27.10	0.6	$16.26
	Payroll Burden %	30%		$4.88
	Total Labour Cost			$21.14
Other	Contract	2.94		$2.94
	Other	2		$2.00
	Total Other			$4.94
Total Cost				$26.08
Specific Service Charge Value Requested				**$26.00**

The standard rate for this service is $30.00 and includes labour costs of $25.48 and vehicle costs of $3.00. The total actual savings for customers is $4.00.

Generic Rates and Model for Deriving LDC Specific Rates				
LDC Name:	***Newmarket-Tay Power Distribution Ltd.***			
Fill in only the blue ranges that are appropriate for the Specific Service Charge Described.				
SSC Description	**Collection of account charge - no disconnection**			
		Rate	**Hours or Units**	**Calculated Cost**
Labour	Direct Labour (inside staff) Straight Time	27.10	0.5	$13.55
	Payroll Burden %	30%		$4.07
	Total Labour Cost			$17.62
Other	Contract	3.30		$3.30
	Other	2.00		$2.00
	Total Other			$5.30
Total Cost				$22.92
Specific Service Charge Value Requested				**$23.00**

The standard rate for this service is $30.00 and includes labour costs of $25.48 and vehicle costs of $3.00. The total actual savings for customers is $7.00.

2

Generic Rates and Model for Deriving LDC Specific Rates

LDC Name:	***Newmarket-Tay Power Distribution Ltd.***			
Fill in only the blue ranges that are appropriate for the Specific Service Charge Described.				
SSC Description	**Disconnect/Reconnect at meter - regular hours**			
		Rate	**Hours or Units**	**Calculated Cost**
Labour	Direct Labour (inside staff) Straight Time	27.10	0.5	$13.55
	Payroll Burden %	30%		$4.07
	Total Labour Cost			$17.62
Other	Contract	27.81		$27.81
	Other	3		$3.00
	Total Other			$30.81
Total Cost				$48.43
Specific Service Charge Value Requested				**$50.00**

If the Standard rates were to be used for the above charges, The Applicant would receive an additional $80,182 in other revenues. However, as shown above, the requested rates are based on actual costs using the model provided with the 2006 EDR rate process. If the standard rates were adopted, The Applicant would be over-charging for this service, resulting in a subsidy of other rates.

Rate Description	**Standard Rate**	**Requested Rate**	**2010 Activity**	**Revenue at Standard Rate**	**Revenue at Requested Rate**	**Difference**
Account set up charge (plus credit agency costs if applicable)	30	26	4,339	130,177	112,820	(17,357)
Collection of account charge - no disconnection	30	23	7,737	232,119	177,958	(54,161)
Disconnect/Reconnect at meter - during regular hours	65	50	578	37,545	28,881	(8,664)
				399,841	**319,659**	**(80,182)**

Proposed Service Rates

Exhibit 3 Tab 4 Schedule 5 Attachment 1 provides the existing rates and for each service area along with the proposed rates and also the impacts of applying the proposed rates.

Within the Newmarket Service Area, The Applicant currently charges the vacating customer a Final Bill fee of $12.50 and the new customer moving in a setup fee of $12.50 for a total of $25 for an account set up fee. Therefore, the total cost of the "Move In/Move Out" was calculated and split between the two customers at $12.50 each. The 2006 EDR rates were developed using "all in" costs with the idea of charging either the new customer or the vacating customer, but not both. The Tay service area charges the new customer only in accordance with 2006 EDR. The Applicant proposes to adopt the Tay approach for the harmonized rates.

Summary of Rates and Impacts

Description	Current Rate - Newmarket	Current Rate - Tay	Requested Rate - THE APPLICANT	2010 Test at Existing Rates		2010 @ Proposed Rates	
		$	$	#	$	#	$
Arrears certificate	8.50	15.00	15.00	184	1,833	184	2,766
Statement of account	8.50	15.00	15.00	197	1,953	197	2,961
Duplicate invoices for previous billing	3.25	15.00	15.00	37	216	37	556
Request for other billing information		15.00	15.00	6	91	6	91
Easement letter	8.50	15.00	15.00	264	2,613	264	3,964
Account history	8.50	15.00	15.00	0	0	0	0
Credit reference/credit check (plus credit agency costs)	10.00	15.00	15.00	951	10,501	951	14,267
Returned cheque charge (plus bank charges)	16.50	15.00	15.00	1,052	17,033	1,052	15,784
Legal letter charge		15.00	15.00	0	0	0	0
Change of Occupancy - Final Bill	12.50	30.00	0.00	3,252	40,649	3,252	0
Account set up charge (plus credit agency costs if applicable)	12.50	30.00	26.00	4,339	58,339	4,339	112,820
Special meter reads		30.00	30.00	0	0	0	0
Collection of account charge - no disconnection	18.00	30.00	23.00	7,737	151,061	7,737	177,958
Disconnect/Reconnect at meter - during regular hours	50.00	65.00	50.00	578	30,369	578	28,878
Disconnect/Reconnect at meter - after regular hours	120.00	185.00	185.00	35	4,358	35	6,551
Disconnect/Reconnect at pole - during regular hours	160.00	185.00	185.00	0	0	0	0
Disconnect/Reconnect at pole - after regular hours	315.00	415.00	415.00	0	0	0	0
Meter dispute test self contained plus Measurement Canada fees (if meter found correct)	25.00	30.00	30.00	0	0	0	0
Service call - customer-owned equipment		30.00	30.00	0	0	0	0
Service call - after regular hours		165.00	165.00	0	0	0	0
Total SSC's					319,016		366,596

OTHER REVENUE VARIANCE ANALYSIS & TABLE

Exhibit 3, Tab 4, Schedule 4, Attachment 1 shows that the only account exceeding the materiality limit of $87,344 is Interest Revenue. This decrease is due to the following reasons:

1) A significant amount of cash flow has been spent on capital programs. In the four year period from f 2006 to 2009 The Applicant has increased net fixed assets by over 9 million (including over 5 million on smart meters and TOU billing which The Applicant funding from its own cash flows.

2) Interest rates are at historical low. The Applicant achieves an interest rate of Canadian Business prime less 1.75 (which is currently 0.5%) on outstanding cash balances.

3) The impacts of “Government Projects” as described in Exhibit 2 – Rate Base are having a major negative affect on available funds. As described, these three projects alone will have cost over $12 M from 2007 to 2010 when completed.

Exhibit 3, Tab 4, Schedule 4, Attachment 1 that follows shows the impacts of these three factors and the associated year-over-year variances.

Other Revenue Variances Table

Account Name	US of A	2007 vs. 2006	2008 vs. 2007	2009 vs. 2008	2010 Test (Current Rates) vs. 2009
SSS Administration Charge	4080	(702)	2,898	1,821	3,443
Retail Service Revenues	4082	4,668	6,677	(628)	(135)
STR Revenues	4084	6,983	(7,429)	2,738	(2,684)
Revenue-Rentals	4210	(17,354)	5,987	3,717	(3,717)
Revenue-Late Payment Charges	4225	8,722	(9,321)	33,193	(20,034)
Specific Service Charges	4235	(21,880)	44,258	(6,101)	10
Revenue-Sale of Scrap Metals	4325	(3,349)	(6,320)	695	(6,695)
Gain on Sale of Assets	4355	(41,526)	(7,622)	3,811	(4,561)
Loss on Sale of Assets	4360	133	0	(995)	995
Revenue-Miscellaneous	4390	49,150	(18,445)	(17,689)	(9,095)
Interest Earned	4405	(80,494)	(278,271)	(94,138)	(88,647)
Grand Total Variances Other Revenue		(95,649)	(267,588)	(73,577)	(131,121)

Exhibit 4:

OPERATING COSTS

Exhibit 4: Operating Costs

Tab 1 (of 8): Manager's Summary

MANAGER'S SUMMARY OF OPERATING COSTS

The operating costs presented in this section represent the annual expenditures required to maintain and operate a safe and reliable distribution system, provide customer billing, communications and support and all other requirements to meet government, financial and environmental regulations, and to comply with all OEB System Codes. These costs are determined in accordance with Canadian Generally Accepted Accounting Principles and organized into two groupings. The first is direct controllable OM&A costs which are: Operation & Maintenance, Billing and Collecting, Community Service, and Administration. The second grouping includes: Interest, Amortization, Capital and Property Taxes and PILS Interest which are outside the control of the Applicant.

OM&A Trend Table and Test Year Levels

OM&A Trend Table

Newmarket Tay Power Distribution Ltd.					
	2006 Actual	**2007 Actual**	**2008 Actual**	**2009 Actual**	**2010 Test**
Operation & Maintenance	1,860,955	1,894,991	1,831,140	2,208,026	2,560,224
Billing & Collecting	1,507,749	1,653,517	1,750,464	1,852,686	2,331,264
Community Relations & Advertising	107,754	79,476	72,007	63,202	76,332
Administration Labour & Exp	2,068,003	2,263,092	2,374,534	2,442,373	2,798,398
Total OM&A	**5,544,461**	**5,891,076**	**6,028,145**	**6,566,288**	**7,766,218**
Interest	1,947,982	1,633,624	1,503,931	1,567,359	2,164,584
Amortization	3,541,888	4,253,215	4,082,048	4,270,472	4,525,690
Capital and Property Taxes	267,475	271,857	260,277	246,309	173,946
Income Taxes (PILS)	2,447,048	1,962,288	1,607,996	1,728,792	1,154,088
Grand Total	**13,748,854**	**13,856,054**	**13,482,397**	**14,379,219**	**15,784,526**

The main points to note when assessing the operating costs are:

1) The 2006, 2007, 2008, and 2009 costs are presented on an actual basis, with only the 2010 costs presented on a forecasted basis.

2) Costs from 2006 to 2010 were accumulated by service area for Tay and Newmarket and then added together to present the applicant's total operating costs on a consolidated basis.

3) There are no sales or corresponding expenses charged between service areas. Costs are allocated to the service area to which they apply. Cost incurred on behalf of both service areas are split by the number of customers; 86% for Newmarket and 14% for Tay.

4) The 2010 forecasted amounts include only half of annual amount paid on OMA for PST. Since the PST was replaced and combined with the HST as of July 1, 2010, the applicant deemed it appropriate to include only one half of the amount of PST that it would otherwise pay. The HST will be applied similar to the GST as a flow through cost. The actual amount of PST paid on OMA expenses in 2008 was approximately $60,000. In compiling the 2010 forecasted amounts the Applicant removed $30,000 from the OMA accounts.

5) The OM&A accounts do not include any non-distribution related expenditures for any CDM or OPA programs, smart grid costs or any other costs that should be recorded in a deferral account unless noted.

6) The Applicant has made the following assumptions when forecasting the 2010 amounts:

- Wage rates were increased by 3%
- Customer Growth was forecast at 2%
- Inflation was set at 2%.

7) The Applicant proposes to recover $7,766,218 of direct controllable OM&A costs through rates in 2010.

8) The rate filing guidelines indicate that “a written explanation is required for variances in operating costs between years of .5% of the overall distribution revenue requirement". The Applicant's proposed Distribution Revenue Requirement is approximately $17,500,000 million, and the associated materiality threshold is $87,500.

9) For 2008; in order to present amounts on a comparable basis to 2009 and 2010, $333,056 of amortization costs has been reallocated from 2008 Operations accounts to the amortization line item.

OM&A Variances

Variances in controllable OM&A from 2008 to 2009 and from 2009 to 2010 are summarized in the following table:

	2008	2009	Change 2008-09		2009	2010	**Change 2009-10**	
	Actual	Actual	$	%	Actual	Test	**$**	**%**
Operation & Maintenance	1,831,140	2,208,026	376,887	20.38%	2,208,026	2,560,224	**352,197**	**15.95%**
Billing & Collecting	1,750,464	1,852,686	102,223	5.84%	1,852,686	2,331,264	**478,578**	**25.83%**
Administration Labour & Exp	2,374,534	2,442,373	67,839	2.86%	2,442,373	2,798,398	**356,025**	**14.58%**
Community Relations & Advertising	72,007	63,202	(8,805)	-12.23%	63,202	76,332	**13,130**	**20.77%**
Total OMA	6,028,144	6,566,288	538,144	8.87%	6,566,288	7,766,218	**1,199,930**	**18.27%**

Each of the OM&A categories set out in the table above is described below:

Operations & Maintenance

Operation and Maintenance in 2010 is forecasted to increase by $726,084 over the 2008 level or a 40% increase.

One of the main drivers of this increase is that the Applicant has changed from a capital intensive focus during the period of 2006 to 2008 to a more balanced approach between capital and maintenance expenditures for 2009 and onward. From 2006 to 2008, the Applicant was involved in intensive capital projects; for example smart meters, and Holland TS. In 2009 the Applicant started to refocus its crews back on maintenance projects and to contract out capital projects to third parties, such as: capital project 193 - Bayview Avenue Feeders to Powerstream, and capital project 214 - Leadbeater DS rebuild. The total amount time reallocated to maintenance projects from capital projects represents approximately the time of less than two linemen on an annual basis.

Another factor in this increase is that the Applicant is replacing two line staff that had left early in 2007; one lineman was replaced January 1, 2009 and the other lineman on January 1, 2010. The Applicant is also forecasting in the 2010 test year the need for a new engineer, primarily to deal with electrical safety standards and asset maintenance management.

From the operation and maintenance expenditures originally occurred in 2002 and 2003; the average annual increase from 2003 to 2009 is 5%.

Billing and Collecting

Billing and collecting expenditures in 2010 are forecasted to increase by $580,800 from the 2008 level or a 33.5 % increase over two years.

The majority of the increase will be incurred in 2010 and the cost increase will be driven by the increased need to develop new systems and processes to manage the time-of-use ("TOU") rates and the significant increases in billing data. The costs that relate to

Smart Meters and TOU billing are forecasted to be approximately $372,000 in the 2010 test year and this represents 64% of the increase. Without the TOU costs, the percentage increase would be 5.9 % annually.

Administration

Administration expenditures in 2010 are forecasted to increase by $423,864 from the 2008 level or a 17.85 % increase over two years. The majority of this increase will be incurred in the 2010 test year. The increase is driven by increased regulatory costs to develop and submit this cost of service application and a significant increase in the Applicants insurance cost. These two factors combined are forecasted to be $210,000 in the 2010 test year and represent 50% of the increase. Without these costs, the percentage increase would be 4.5% annually.

The OM&A Expense tables required by the filing requirements are set out in the attachment to this schedule. The Applicant has also included data to illustrate the variances in the absence of the unique cost drivers described above.

Attachment 1 (of 1):

OM&A Expense Tables

OM&A Expense Table

	Last Rebasing Actuals 2008	Bridge Year Actuals 2009	% Change	$ Change	Test Year Forecasted 2010	% Change	$ Change
Operations and maintenance	$ 1,831,140	$ 2,208,026	21%	$ 376,886	$ 2,560,224	16%	$ 352,198
Billing and Collecting	$ 1,750,464	$ 1,852,686	6%	$ 102,222	$ 2,331,264	26%	$ 478,578
Administrative	$ 2,374,534	$ 2,442,373	3%	$ 67,839	$ 2,798,398	15%	$ 356,025
Community Relations	$ 72,007	$ 63,202	-12%	$ (8,805)	$ 76,332	21%	$ 13,130
Total	$ 6,028,145	$ 6,566,287	9%	$ 538,142	$ 7,766,218	18%	$ 1,199,931

Percent ChangeTest year vs. Most Current Actuals	18.27%
Percent ChangeTest year vs. Last Board Approved Rebasing Year	28.83%
Average for Y1, Y2, Y3	14.42%
Compound Annual Growth Rate (for Y1, Y2, Y3)	13.5

Adjustment

smart meter costs	$372,000.00
Regulatory rate filing costs	$150,000.00
Increase in Insurance costs	$60,000.00
New Engineering staff	$135,000.00

Normalized OM&A Expense Table

	Last Rebasing Actuals 2008	Bridge Year Actuals 2009	% Change	$ Change	Test Year Forecasted 2010	% Change	$ Change
Operations and maintenance	$ 1,831,140	$ 2,208,026	21%	$ 376,886	$ 2,425,224	10%	$ 217,198
Billing and Collecting	$ 1,750,464	$ 1,852,686	6%	$ 102,222	$ 1,959,264	6%	$ 106,578
Administrative	$ 2,374,534	$ 2,442,373	3%	$ 67,839	$ 2,588,398	6%	$ 146,025
Community Relations	$ 72,007	$ 63,202	-12%	$ (8,805)	$ 76,332	21%	$ 13,130
Total	$ 6,028,145	$ 6,566,287	9%	$ 538,142	$ 7,049,218	7%	$ 482,931

Percent ChangeTest year vs. Most Current Actuals	7.35%
Percent ChangeTest year vs. Last Board Approved Rebasing Year	16.94%
Average for Y1, Y2, Y3	8.47%
Compound Annual Growth Rate (for Y1, Y2, Y3)	8.14%

DETAILED ANALYSIS OF OM&A COST DRIVERS

The following table quantifies the significant OM&A cost drivers:

Cost Drivers			
	Account	**2009 Actual**	**2010 Test**
Overall Increase		538,144	1,199,930
Billing Collecting			
Increase in bad debts	5335	15,000	
Net Smart Meter TOU incremental costs	5310/5315		373,000
Postage	5315	12,000	16,000
Wage Increase	5305/5310/5315	26,000	30,000
All other Changes		49,222	59,578
Total Billing and Collecting		**102,222**	**478,578**
Administration			
Increase in Regulatory Filing expenses	5630		150,000
Increase in Mearie Insurance costs	5635		60,000
Wage Increase	5610/5615/5675	44,000	46,000
Cleaning contract	5675		10,000
Increased Phone costs for IVR in Tay	5620		10,000
Security	5620		5,000
HVAC	5620		4,000
All other changes		23,839	71,025
Total Administration		**67,839**	**356,025**
Operations and Maintenance			
Increase in direct wages charged to OMA		133,000	
Increase in staff compliment of one engineer			135,000
Increase in Tree Trimming	5315		54,000
Increase in wages		60,000	60,000

increase in wages to replacing lineman		30,000	30,000
All other changes		153,887	73,198
Total Operations and Maintenance		**376,887**	**352,198**
Community Relations			
All other Changes		(8,805)	13,130

The Applicant is responsible for maintaining distribution and infrastructure assets deployed over 47 square kilometers (including 342 kilometers of overhead lines and 14 kilometers of underground lines) within the Tay service area; and 41 square kilometers (including 243 kilometers of overhead lines and 416 kilometers of underground lines) within the Newmarket service area.

Since 2008, total direct OM&A has increased by 14.38% per annum with the highest increases occurring in the Operation and Maintenance expenditures.

Operations and Maintenance

In 2009 the operations and maintenance expenditures increased by 20.58% over 2008 or $376,887. For 2010 the forecasted expenditures are to increase by 15.95% over 2009 or $352,197.

2010 Operations and Maintenance Cost Drivers

There were no individual accounts that exceeded the majority threshold between 2009 and 2010. The majority of Cost drivers between 2009 and 2010 are wages and thus allocated over a number of maintenance accounts.

On a global level for 2010, the Cost Drivers are:

1. A new engineering position.	$135,000
2. Increase for tree trimming within the Tay service area	$ 54,000
3. Increase in operating wages attributed to a apprentice	$ 30,000
4. 3% increase in wages	$ 60,000
5. All other changes	$ 73,197

Additional Engineer $135,000

Due to growth within in the distribution system, to ensure continued safety and reliability, and to satisfy the increased regulatory requirements (e.g. Electrical Safety Authority "ESA" bulletins, asset management programs and documentation) the applicant requires an additional engineering position.

Since 2002 and through the amalgamation with Tay, (which doubled the applicant's service territory) the Applicant has employed only one professional engineer, one engineering manager, and two engineering technicians to provide all engineering required responsibilities. These positions are currently experiencing significant amount of overtime and competing priorities.

To satisfy the need for a more integrated and focused approach to asset management, to maintain and enhance the existing distribution system and to implement all of the ESA bulletins; the Applicant's current staff complement is finding that all aspects of these responsibilities cannot be adequately addressed. Therefore the Applicant has determined that another engineer is needed. The current positions will continue to be fully deployed in the 2010 test year until an additional engineer can be retained.

This position will be fully dedicated to monitoring, assessing, and evaluating the Applicant's overall distribution system, on a regular basis and implement a formal plan for asset maintenance. This will result in optimal utilization of the system, prioritization of maintenance dollars and resources to maximize asset utilization, increase system reliability, and lower system losses.

In addition to asset management this position will be responsible for ensuring that the distribution system and materials of the Applicant are compliant with all current ESA bulletins and good utility practices. Over the last few years the amount of documentation necessary to remain compliant with the ESA standards has been ever increasing. While the applicant has not previously increased its staff complement to deal with these new ESA issues, it has increased its service territory and is responsible for another 47 square kilometers in Tay. This ESA monitoring and compliance is currently divided among two management and two staff positions. This new position will be responsible for centralizing ESA activities, analyzing the requirements and ensuring the Applicant is compliant with all appropriate regulations.

With this new position there will be some opportunity to reduce current overtime costs among the four individuals managing ESA and asset management activities. The two management positions do not qualify for overtime pay. The Applicant reviewed the overtime timesheets of the two staff operations technicians; in 2009 they worked 600 hours of overtime. Assuming the management staff works at a similar level of at least 15% overtime, this group incurs over 1,200 hours of overtime on an annual basis. When the Applicant fills this new position it expects overtime hours to decrease concurrent with the implementation of the asset management plan and centralization of ESA compliance.

Tree Trimming $54,000

The Applicant has an annual tree trimming program to ensure the safety and reliability of its distribution system. The Applicant maintains 47 square kilometers with 342 kilometers of overhead lines in the Tay service area; and 41 square kilometers with 243 kilometers of overhead lines in the Newmarket service area. The Applicant proposes to increase the tree trimming budget in 2010 to $177,236 which is consistent with the 2008 expense; as the Applicant expects a comparable level of work to be performed in the test year. The Applicant expects that level will increase over the IRM period due to the rapid growth of young trees planted within the past twenty years that are encroaching on the safe proximity from the Applicant's lines as recommended by ESA. The Applicant contracts the majority of the annual tree trimming program to a third-party. The Applicant inspects one third of the Newmarket service area annually and schedules the third-party to remove vegetation that is in close proximity to the lines.

In the Tay service area, tree trimming prior to amalgamation was performed on an ad-hoc basis. The Applicant started a routine maintenance program in 2008 and incurred an $85,000 cost in that year. However due to competing priorities, the applicant had to scale back tree trimming expenditures in 2009. Tay has a greater number of overhead kilometers (342 in Tay compared to 243 in Newmarket) with more, older and bigger trees. The Applicant is establishing a tree trimming schedule in Tay under the same parameters as the Newmarket service area. The tree trimming forecast in Tay is increasing to annual forecasted amount of $80,000, bringing the consolidated total to $177,236.

Apprentice $30,000

The Applicant has returned to a normal staff complement of 20 FTE of line staff in the Newmarket service area. This rectifies an understaffing situation that has existed since 2007 when one line staff retired and another resigned. They were not immediately replaced. The Applicant instead relied upon contract line men, several Cambrian powerline technician co-op students on short rotations, along with increased overtime and postponement of discretionary overhead line maintenance projects through this period. These arrangements were not sustainable.

The Applicant has hired two graduates of the Cambrian College powerline technician program: one in January 2009 and the other in January 2010. Both of these new hires performed their Co-op placement with the Applicant. The applicant prefers to hire graduates from an accredited college program such as Cambrian College as the apprentice period is shorter and the Applicant’s apprentice training costs are reduced. The applicant forecasted that 40% of the apprentice’s time would go to capital projects.

Wage increase and Inflation

Wage increases are set at 3% annually based upon a collective agreement which expires in 2013. For the allocation of wages the Applicant assumes a historical split whereby 50%-60% of the total wage cost is allocate to operating accounts and 40%-50% to capital projects. Based upon this historical split an additional $60,000 operating wage costs has been forecasted to be incurred in the test year. Inflation and customer growth are both forecasted at two percent during the 2010 test year.

2009 Operations and Maintenance Cost Drivers

The majority of Cost Drivers between 2008 and 2009 are wages and thus allocated over a number of maintenance accounts.

On a global level for 2009, the Cost Drivers are:

1.	An increase in wages being charged to OM&A.	$133,000
2.	Increase in wages due to union contract	$ 60,000
3.	increase in wages for replacing a lineman to a apprentice	$ 30,000
4.	All other changes	$153,887
	Total	$376,887

Increase in wages being allocated to OM& A operational accounts - $133,000

In 2009 the applicant has returned to its historical allocation of spending 55% to 60% of its available labour time on maintenance related projects. This represents a reallocation of the time of 1.5 linemen from capital projects back to maintenance of the plant on an annual basis.

In the Newmarket service area, using 2002 and 2003 costs as a base; the 2010 forecasted costs represent an annual increase of 5% since 2002 and 2003. A 5% per annum is consistent with the Applicant's customer growth and the negotiated wage increases over the same period.

The Applicant has spent the last few years on capital intensive projects which have decreased its labour hours available for its annual maintenance program. The Applicant reviews one third of its distribution system annually and identifies and prioritizes ongoing maintenance projects to ensure system reliability, safety, and efficiency. This is an ongoing process. The Applicant prioritizes projects in a similar manner as capital projects. Please see Exhibit 2 for a description of this process. The Applicant routinely performs preventative maintenance to avoid a more costly full capital replacement. However, due to certain large mandated capital projects, the Applicant fallen behind on its maintenance schedule.

The Applicant is now experiencing ever greater time constraints in the field. With increased standards required for safety on work sites and the decreased time available to work on regional roads due to legislative changes. The Applicant has experienced an increase in the amount of time allocated for jobs. This has forced the Applicant to make changes to certain operational practices. In 2009 the Applicant had to schedule outages after hours and on weekends to accommodate these changes.

Those above-mentioned factors combined with employee vacations and sick time have put significant constraints on the Applicants ability to complete its required maintenance and capital projects. Therefore the Applicant has found it prudent to contract out large capital jobs; such as Bayview pole rebuild egress from Holland TS, Eagle Hills underground rehabilitation and the Leadbeater DS. By prudently outsourcing large capital projects, the Applicant now has the flexibility to continue its annual preventive maintenance program and capital jobs where needed.

Apprentice $30,000

The Applicant has returned to a normal staff complement of 20 FTE of line staff in the Newmarket service area. This rectifies an understaffing situation that has existed since 2007 when one line staff retired and another resigned. They were not immediately replaced. The applicant instead relied upon contract line men, several Cambrian Powerline technician co-op students on short rotations, along with increased overtime and postponement of discretionary overhead line maintenance projects through this period. These arrangements were not sustainable.

The Applicant has hired two graduates of the Cambrian College Powerline technician program: one on January 1 2009, and the other on January 1 2010. Both of these new hires performed their Co-op placement with the Applicant. The Applicant prefers to hire graduates from an accredited college program such as Cambrian College as the apprentice period is shorter and the Applicant's apprentice training costs are reduced. The Applicant forecasted that 40 % of the apprentice's time would go to capital projects.

<u>All other Changes - $153,887</u>

The majority of these changes relate to burden costs that is charged with direct labour hours. The Applicant's burden rate is approximately 110 % of the cost of direct labour hours and includes direct allocation of benefits, statutory holidays, sick time, post employment costs certain vehicle costs – fuel and maintenance, general engineering time, equipment maintenance and supplies.

Billing and Collecting Cost Drivers

The Applicant bills and collects on a monthly basis for over 31,000 customers within the Tay and Newmarket service areas. The majority of expenditures incurred for Billing and Collecting have remained consistent from year to year. They include IT, contract service costs, wages, benefits, materials, and postage. These costs rise annually with inflation and the number of new service connections. Up to fiscal 2009 the only the major variance since 2007 was due to a rise in bad debts from the economic downturn.

For 2010, Billing and Collecting is expected to increase by 25.83%. The majority of the increase is due to the implementation of Smart Meters and Time-of-Use (TOU) pricing. The Provincial Government (through Ontario Regulations 428/06, 427/06 and 426/06) outlined the Smart Meter initiative and named the Applicant as a priority implementation LDC.

The Applicant has been billing all eligible residential customers on TOU pricing through 2009. In 2009 costs associated with TOU billing have been recorded in a deferral account and are being offset by a rate adder. Through this application, in 2010 and onward the Applicant is seeking to classify currently incurred Smart Meter and TOU billing expenditures as regular OMA costs.

2009 Billing and Collecting Cost Drivers

There were no material Billing and Collecting cost drivers in 2009.

2010 Billing and Collecting Cost Drivers

For the 2010 test year the cost drivers are:

Smart Meters Drivers:

1. 5310- cost for validating and reviewing MDM/R reports	$150,000
2. 5310- cost for a Operational Data Storage (ODS) system	$ 56,000
3. 5315-Software Maintenance Costs	$ 33,000
4. 5315-Automated Meter Infrastructure (AMI) Security Audit	$ 23,000
5. 5315- Other- IESO – Provincial MDM/R fees	$110,000

Other Cost Drivers:

6. 5315- Postage	$ 16,500
7. 3% increase in wages	$ 30,000
8. All other changes	$ 60,000

It should be noted that, prior to the Applicant's implementation of an AMI system in accordance with the provincial government's Smart Meter mandate, the previously installed electromechanical and electronic consumption meters required walk-up reads. These meter readings were performed by a contracted third-party. With the implementation of the AMI, they have been superseded by electronic readings contracted to another third-party through an RFP process. The costs of the electronic reads are not materially different from the walk-up readings. Therefore there has been no adjustment for the new electronic read cost.

While there is an expectation that AMI systems in and of themselves create efficiencies in billing and other utility operations, the Applicant, in its specific circumstance has not found this to be the case. The Smart Meter initiative as implemented in Ontario to collect hourly consumption data and calculate TOU bills has created a need for the Applicant to implement new IT systems and diligence measures for data management and data correction. As such, billing costs have increased in response to the added workload and related IT system costs. However, the amalgam of hourly consumption, power system parameter measurement and meter health data that the AMI gathers will create new paradigms for operation and management of the Applicant's distribution system. Some of these may create efficiencies, increases in reliability and improved commodity management, but only when the quantum of data is optimized and presented for homogeneous use by all functions in the utility. Effectively, the AMI system, when implemented prudently, becomes an enabler of efficiency and improved asset management practices. It is imperative that, in order to exploit the value of the AMI data, appropriate systems and business processes are implemented at the same time as the AMI to ensure the utility can extract full value from it.

If the Applicant had not incurred the TOU and Smart Meter costs, the Billing and Collecting cost increase for 2010 would have been only 5.7% over 2009.

I. $150,000 is the additional annual cost of the processing and examining of the meter data exception reports from the provincial meter data management repository ("MDM/R "). There are a number of reports issued by the MDM/R on a daily basis which need analysis and further action. These consist of:

Daily Read Status Report
Excessive Missing Reads Report
Missing Reads Detail Report
Interim Data Collection: No Device Found
Zero Consumption

Interim Validation Failure
Missing Interval Aging
Billing Delivery Summary Report
Unauthorized Usage Report
Re-Billing Report
Billing Delivery Detail Report
Billing No Reads Report
Universal SDP ID Assignment Request
Synchronization Updates Report
Synchronization Exception Report
Incomplete Synchronization Report
FTS Processing Failure Report

The Applicant, through 2009 is using the MDM/R for billing quantity data for all residential customers on TOU pricing. It is still working with the MDM/R in a local test environment provided in conjunction with the ODS to develop generic Smart Meter configurations, data management protocols and business process changes for billing GS<50 consumers eligible for TOU pricing. As such, all meter data exception reports listed above that is produced from the MDM/R on a given day must be reviewed and appropriate corrective action taken. Meter data exceptions are corrected using a combination of algorithm based measures using the ODS and manual intervention. The additional monthly time requirement can be up to 290 person hours. If the Applicant was to perform this function internally it would require two FTE’s plus supervision and materials and would cost the applicant approximately $160,000 in the 2010 test year. The Applicant presently contracts this activity to a third-party. The Applicant has routinely tested the cost of internalizing new functions brought about by Ontario’s electricity market opening and evolution against services offered by third-party service providers and utilizes the most prudent approach.

II. $56,000 of the increase is due to the inclusion of an annual meter Operational Data Storage (ODS) system service contract with Savage Data Systems (“Savage”). It is expected that these costs will continue to be incurred through the entire rebasing period. This contract has recently been reviewed and Savage Data had the most relevant experience and offered the most reasonable price.

The ODS provides three essential functions not performed by the provincial MDM/R:

- Manipulation of metered consumption data for use by a web presentment graphical interface to display this data for customers as required by provincial regulation. The ODS generates bulk validated consumption data in conjunction with the provincial MDM/R and serves it to the Applicant’s Customer Information System (CIS) graphical interface. The CIS cannot interface directly with the MDM/R for this purpose as it creates excessive processing time for both systems.

- Collection, cataloging and presentment of power system parameters (voltage, power fail, tamper) and meter health reported by the AMI for the Applicant. This data is analyzed through a graphical interface to ascertain meter health, assist in the management of the Applicant’s field assets and local system reliability. It is also used to identify voltage and outage problems within the distribution system, provide indication of theft of power through meter tampering and to ensure the AMI system operator is meeting its contractual service level obligations. The ODS will also serve data to the Applicant’s planned GIS data system such that it can be integrated into real time asset management and provide homogenous determinates to be used in assessing the health of assets as part of an overall asset management plan; and

- Availability of algorithms to interface with the provincial MDM/R for verifying, editing and estimating (VEE) metered consumption data in response to critical MDM/R exception reports where the MDM/R’s automated VEE process failed and the timing or accuracy of customers bills would be affected.

The ODS also continues to provide a test environment in support of the Applicant's priority implementation efforts. Initial migration of billings to TOU pricing uses the ODS for two reasons:

- verification of local billing processes; and

- Generation of a three month previous history of TOU consumption patterns. This history is included in each consumer's TOU introductory package as part of the Applicant's on-going education program.

Once TOU rates are introduced and billing processes are verified, the data source for billings can be migrated to the production system environment of the provincial MDM/R.

III. Software costs $33,000

Incremental software costs will be incurred in two new areas for Smart Meters and TOU data processing:

a. $16,000 is for a data co-ordination management system to ensure the various systems are synchronized with one another. The Applicant recognized that there will be an on-going need to synchronize field meter activity between the CIS, the AMI and the MDM/R. Any time there is field activity involving a Smart Meter, the CIS, AMI and the MDM/R must be updated. Failure to do so results in meter data exception reports being generated by the AMI and MDM/R with a resulting loss of meter data at the MDM/R. The Applicant's CIS vendor provides a simplified Work Force Management System (WFMS) interface that is dedicated to this kind of ongoing service order activity, called MCare. While the base MCare system does not, itself, have all the functionality necessary for Smart Meter management, it provides an economical interface to a full function WFMS with the required functionality and field handheld devices for data collection that are ergonomically acceptable for use by field staff. The Applicant recognizes that the scale of capital and maintenance costs for a full function WFMS is beyond its ability to justify within the context of managing field activities associated with Smart Meters alone. As such, the WFMS is supplied through an annual service fee paid to a contract third party provider. The supply of WFMS capability was part of an RFP for meter supply, and installation. The system is required to ensure the integration of the CIS system, to the MDM/R and any other Smart Meter data collection applications. As a result, annual software maintenance costs will increase but significant capital costs will be avoided. Furthermore, additional changes and modification may be required to the systems to ensure ongoing reliable operation and communication as the Applicant implements TOU pricing in the GS<50 customer class.

b. $17,000 is for an annual maintenance cost of software modules within the CIS which allow validated consumption data to be presented to customers to view their consumption in a readily accessible form over the internet, called ECare and the previously discussed MCare to manage Smart Meter field activity.

The ECare module receives validated consumption data from the ODS and allows the consumer to view it in hourly or in TOU period formats. Both billed and unbilled quantities are available in conformance with government regulations. Viewing their consumption within hours of usage is another powerful tool in assisting consumers to take up the benefit of TOU rates. On average the Applicant has seen approximately 20 percent of its residential customers register for secure access to view their TOU data over the internet. On a monthly basis 5 to 10 percent of the Applicant’s customers view their usage over the internet. An additional benefit is that this feature is encouraging a number of calls into the call centre from customers with questions concerning TOU data, rates, and conservation queries.

IV. Security Audits $23,000

With the mass deployment of AMI systems currently under way, 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. Now that network infrastructure is being installed in the field, there is a requirement for additional security measures to ensure that utility data and equipment are kept secure from manipulation or other forms of illegitimate control.

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; and
- Tampering with demand side management tools which can be controlled through smart meters.

Since 2007, the Applicant has been working with its AMI system and Vendor to understand the security features of the network, best practices for its deployment and new features that are being developed for future implementation. In November of 2009 the Information and Privacy Commissioner of Ontario released the report Smart Privacy for the Smart Grid which identified areas of concern to be addressed in the area of Smart Meter and Smart Grid devices. As all residential class consumers are now billed using the Applicant's AMI system, it is essential that a regime of periodic security audits be conducted.

The Applicant will be conducting periodic AMI security audits and will incur a $23,000 annual increase for this purpose. This will ensure compliance with government and industry privacy requirements and ensure the Applicant is adhering to best practices in managing consumer data. The audit will test that the AMI service provider has appropriate controls over the transmission and collection of customer data. Selection of the audit firm is currently undergoing a competitive RFP process being conducted by a consortium of Ontario LDCs who are working together to minimize cost and maximize time effectiveness.

V. IESO MDMR processing costs $110,000

The Applicant has not received a bill for provincial MDM/R processing from the IESO. At the time of this application, the IESO has not submitted an application nor has it received OEB approval to charge for this service. It is the Applicant's understanding based upon correspondence from the Electricity Distributors Association that the provincial MDM/R fee will be 28 cents per enrolled meter per month. As the Applicant has all its residential Smart Meters enrolled in the provincial MDM/R and the meter data being processed in a production environment, the Applicant reasonably expects to receive an annual charge from the IESO of approximately $110,000. Accordingly, this amount has been included in the test year Billing and Collection costs recorded in Account 5315.

Other Cost Drivers (2010)

Controllable Other Costs can be broken down as follows

Postage increases	16,500
Printing and Stuffing	20,000
All other	20,573
Total	57,073

5315 - Postage $16,500

Postage costs are budgeted to increase by $16,500 per annum. The reasons for these increases are:

- the annual growth of customers
- the increase in postal rates of two cents as at January 1, 2010
- a general increase in number of letters being disseminated from service area office locations

5315 - Printing and Stuffing $20,000

Printing and Stuffing of bills are budgeted to increase by $20,000 per annum.

The Applicant expanded the bill presented to include a graphical explanation of their commodity charges. The charges are presented in both a tabular (bar chart) and composite (pie chart) format. The expanded bill was initially introduced as part of the Applicant's public education program.

As an added benefit, during an OEB approved TOU Pricing Pilot (EB 2007-0776) the consultant retained to perform the evaluation, Navigant Consulting Inc. found that the most helpful resource for consumers in understanding TOU pricing was the tabular presentation of their consumption included with their electricity bill[1]. For these reasons, the Applicant plans to use the expanded bill format for all consumers. The expanded bill requires an additional page to completment the original doubled sided single sheet bill. The additional page gives rise to a 26 percent increase to the cost of billing and stuffing. This service is provided by a third-party.

Administration Cost Drivers

The Applicant prudently incurs administration expenses to provide services on a commercially viable basis, to adapt to the ever changing regulatory and legislative landscape in Ontario, and fulfill the responsibilities of an incorporated entity. The related expenses include board costs and governance activities, general management and administration wages, information technology, communication, accounting, secretarial, training, software, utilities and rent.

The Applicant has two administration centers, one in Newmarket, and one in Tay to provide local service to customers. The Applicant rents the location in Newmarket and owns the land and building in Tay. The Applicant's administration staff has been stable in both number and composition over the periods.

The Applicant appropriately manages its IT infrastructure of computer hardware, computer software, telecommunications devices, and applications on a coordinated basis and takes all appropriate steps to protect information. The in-house IT staff complement is augmented cost-effectively with the use of specialized third-party service providers. With the passage of the Electricity Act in 1998, the Applicant has routinely tested the cost of internalizing new administrative functions brought about by Ontario's

[1] Evaluation of Time-Of-Use pricing Pilot presented to Newmarket Hydro, March 4, 2008 page 27.

electric market opening and evolution against the cost offered by third-party service providers and utilizes the most prudent approach.

2009 Administration Cost Drivers

There were no material Administration cost drivers in 2009

2010 Administration Cost Drivers

The Applicant has had a stable Admin cost structure in 2008 and 2009 and for the most part 2010 with the exception of increased costs for insurance and the 2010 Cost of Service application. The 2010 forecasted expenditures represent a 14.58% increase over 2009 or $356,025. If the Applicant had not incurred the increased regulatory and insurance costs totaling $210,000, the increase in Admin costs would have been less than 6% over 2009.

The majority of the 2010 increase of $356,025 can be attributed to following main drivers

1.	5630 - Increase in Regulatory Filing expenses	$150,000
2.	5635 - Increase in MEARIE Insurance costs	$ 60,000
3.	5610/5615/5675 - 3 % wage increase	$ 46,000
4.	5675 - Cleaning contract	$ 10,000
5.	5620 - Increased Phone costs for IVR in Tay	$ 10,000
6.	5620 - Security contract increase	$ 5,000
7.	5620 - HVAC contract increase	$ 4,000
8.	All others	$ 71,025
	Total	$356,025

There were no accounts with variances from 2008 to 2009 that exceed the $87,500 materiality threshold and only two that do in 2010, those being Regulatory costs, and Insurance.

Regulatory $150,000

Increase of $193,000 over 2009.

$150,000 of this increase is due to the annual amortization over four years of the cost of this application. The total cost of the applicant's 2010 application is forecasted to be $600,000. The amount is derived as follows:

Elenchus	217,000
Legal	100,000
Intervener costs	100,000
Navigant TOU study	90,000
Un-recovered 2008 EDR costs	93,000
Total	600,000

The Applicant has estimated the above costs based on its 2008 application. Depending on the breadth and scope of the adjudication process to deal with this application, these costs could rise significantly.

Elenchus $217,000

The Applicant as a result of the 2009 settlement was requested to submit a much more complex harmonized rate application for 2010 or 2011. The Applicant elected to file the harmonized cost of service application for 2010. In order to prepare this more complex application within a reasonable time frame, the Applicant identified a need for incremental resources and retained Elenchus. Their fees include project management, the preparation of load forecasts, the use of proprietary software applications, assistance in the preparation of written pre-filed evidence and expert evidence.

Legal Costs $100,000

The Applicant is expecting to pay approximately $100,000 to have legal representation in all phases of the OEB processing of this application. The applicant has retained a well qualified legal counsel, who was actively engaged in its 2008 cost of service application.

Intervener costs $100,000

During the previous cost of service process the Applicant paid over $52,000 to three intervener groups for a review of the initial application, two sets of interrogatories and settlement costs. Versus its 2008 EDR the Applicant expects that more interveners will participate in this application, and that they will perform a more detailed review of the application. These assumptions reflect the Applicant's unique position with respect to the deployment of smart meters, incurring costs to bill customers using TOU rates and its analysis of the costs allocable to the Street Lighting customer class.

Navigant TOU study $90,000

The Applicant engaged Navigant Consulting to analyze the impact of Smart Meters and Time of Use pricing on residential consumption levels. The Navigant study illustrated that energy consumption would not exhibit a material change with TOU. A copy of this draft report is provided as an appendix. This report has been made available to a number of groups who were interested in the effects and impacts of TOU rates, including the OEB, IESO, MEI and the Office of the Environmental Commissioner of Ontario.

Un-recovered 2008 EDR costs $93,000

In 2008 the applicant had only incurred $15,000 in actual costs related to third-party expenses for its 2008 EDR application. In 2009, the applicant paid an additional $108,000 for costs related to that application for legal counsel and OEB authorized intervener cost awards. The applicant's total expense for its 2008 cost of service application was $123,000. The applicant as part of its settlement agreement had its distribution rates set based on its 2008 actual costs incurred. Therefore the currently authorized distribution rates recover only $15,000 annually. At the end of 2009, the applicant had thus only recovered $30,000 out of the total $123,000. Thus the majority of the costs to defend the 2008 rate application remain yet to be recovered. The Applicant proposes to record this remaining amount as a component of its 2010 regulatory cost and to recover this amount over the next four years, from 2010 to 2013.

Insurance $60,000

The Applicant is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). The Applicant acquires its Property, Vehicle and Comprehensive Liability insurance through MEARIE. Property insurance premiums are expected to increase significantly in 2010 versus 2009. This is because MEARIE changed insurance providers in 2010. The new insurance provider increased the annual premium on property insurance for the following reasons:

1) higher claims experience over the past few years that need to be recovered through increased premiums;

2) to reflect actual replacement values rather than historic values; and

3) to appropriately reflect increased risks of aging electric distribution infrastructure within the province, specifically the increased likelihood of equipment failures.

Other

Wage increase and Inflation $46,000

Wage increase is assumed to be 3% which results in approximately $46,000 in costs.

Cleaning Contract $10,000

The Applicant has switched its janitorial provider and increased the frequency of janitorial work on the Newmarket building due to sanitation concerns raised by all staff. This has increased the annual cost. The janitorial company now cleans the building on a daily basis instead of twice a week. This janitorial company was chosen by way of a competitive quote.

Phone costs for IVR in Tay $ 10,000

The Applicant will be extending its Interactive Voice Response system to the Tay service area to enhance customer satisfaction and better manage customer contacts. This system will allow customers to pay bills after hours with credit cards, check their account balances, in addition to providing general information and allowing the applicant to dial out to customers. Also this system will allow for a redundancy backup within the customer service groups, the applicant can switch the phone lines so that customer calls can be taken in Tay or Newmarket. The applicant will incur extra long distances costs and will incur the cost of additional three additional phone lines to provide this enhanced flexibility.

Security Contract $5,000

The Applicant has recently upgraded the building security at its Newmarket location with controlled access to the building and security cameras for the protection of staff. There has been a corresponding increase in annual maintenance fees to reflect the provision of greater security services.

HVAC $4,000

Upon retirement of previous HVAC contractor the applicant procured replacement services based upon a competitive process.

Exhibit 4: Operating Costs

Tab 2 (of 8): Specifics of OM&A Expenses

OM&A PER CUSTOMER AND PER FULL TIME EQUIVALENT

The following table presents the Trend analysis of OM&A by Customer and OM&A full time staff equivalent.

OM&A Cost per Customer and FTEE			
	2008	**2009**	**2010**
Number of Customers	31,385	32,131	32,672
Total OMA	$6,031,144	$6,566,288	$7,766,218
OMA cost per customer	$192	$204	$238
Number of FTEE's	53	54	56
FTEEs/Customer	592	595	583
OMA cost per FTEE	$113,795	$121,598	$138,682

Incentive Plans

For supervisors, The Applicant has an incentive plan which allows then to earn as part of their compensation an amount equal to approximately 5 percent of their base salary. In order to achieve this additional compensation the individual must at a minimum have a satisfactory annual employee review and meet the goals and objectives as set out in the annual review. The goals and objectives are tied to the corporate objectives of the applicant. These goals and objectives are safety, reliability, excellence in customer service, environmental stewardship, and financial integrity.

Benefits

Included in the benefits cost are the employer portion of Employment Insurance, Canada Pension Plan, Employee Assistance plans, Employer Health Tax, Workers safety and Insurance Board payments, Benefit premiums and the employer pension paid to the Ontario Municipal Employees Retirement System.

	Benefits as a Percentage of Average Earnings								
	2008 ($)	2008 average per employee ($)	benefits as a % earnings	2009 ($)	2009 average per employee ($)	benefits as a % earnings	2010 ($)	2010 average per employee ($)	benefits as a % earnings
Management	139,981	19,997	20%	145,141	20,734	20%	152,669	21,810	20%
Supervisors	189,797	18,980	22%	192,230	19,223	22%	228,272	20,752	23%
Non unionized	201,137	13,409	27%	211,938	14,129	28%	220,429	14,695	28%
Unionized	367,743	17,512	25%	399,352	18,152	25%	433,123	18,831	26%
Total	898,658	16,956	24%	948,661	17,568	24%	1,034,493	18,473	24%

ONE-TIME COSTS

The Applicant also incurs a number of one-time expenses on an annual basis. The Applicant budgets for a number of outside services however these are recurring in nature as demonstrated by the continual use of these services. These include OEB audit legal, EDA membership dues and consulting services. The Applicant in account 56300 has budgeted $25,000 per annum or $100,000 throughout the rebasing period for one-time consulting costs throughout the period. Most of these costs are expected to be incurred in 2011. These costs include:

Costs related to developing and implementing mandatory policies and programs on Bill 168. Bill 168 or the *Occupational Health and Safety Amendment Act* was enacted by the Provincial Government on December 15, 2009 and comes into force on June 15, 2010. This act deals with the potential of harassment and violence in the Workplace. The Applicant expects to incur $25,000 in external consulting cost.

Administrative Structure Review for $35,000. The Applicant has engaged BDO to review existing job duties, responsibilities, and workload for all non-union employees. The process started in the summer of 2008 and had to be delayed due to the continuing Cost of Service Filings and is now expected to be completed in 2011.

The Applicant in 2011 is expecting to undertake a full IT/ERP audit of its internal and external systems. The Applicant has ever increasing responsibilities to ensure customer privacy is kept confidential and the fact the Applicant has grown in size, locations, and complexity since deregulation. The Applicant has not had an external third-party audit that focuses solely on its computer equipment, IT process and its data process. The Applicant expects this to cost approximately $30,000.

The Applicant to ensure that it is compliant with all current environmental regulations will be conducting a “mini “audit of the Tay service area. The Applicant expects this review to cost $10,000.

The forecasted total of these one-time costs are $100,000 or $25,000 over four years of this cost of service applicant and IRM period.

Budget Process

The Applicant determines its annual costs through its budget process. The Applicant actively reviews its actual costs and uses costs incurred to predict future year's expenses. Using the prior expenditures as a base, it then adds or subtracts costs that are needed on a one time or annual basis. After the budget has been approved, actual results are matched quarterly to ensure compliance with forecasts. Outlying accounts are noted and reviewed.

Accounts for Administration and Billing and Collecting are managed on an account by account basis. Due to the unpredictable nature of operational expenditures, budgeted expenditures are estimated which are then used to build to a global operational forecast. Operational budgets are then managed on a global basis rather than a account basis.

During the budget process the applicant assigns the highest review criteria to its largest expenses. The Applicant has routinely tested the cost of purchasing new products and additional staff against the need and cost. These are then compared to those services offered by third party service providers and then the applicant utilizes the most prudent approach.

CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT

The Applicant had not included any costs related to the Green Energy Act.

CHARITABLE DONATIONS

The Applicant does not issue donations to charity groups or any other groups.

CONSERVATION & DEMAND MANAGEMENT PROGRAMS

The proposed revenue requirement does not include any non-distribution related expenditures for any CDM amounts and the Applicant confirms that programs being funded through OPA that are also not included in the Revenue Requirement.

Exhibit 4: Operating Costs

Tab 3 (of 8): OM&A Variance Analysis

OM&A VARIANCE ANALYSIS

Billing and Collecting

		2006	2007	2008	2009	2010 Test
		Actual	Actual	Actual	Actual	
Bill & Collect - Supervision	5305	106,545	109,049	119,870	112,813	117,842
Reading-Labour, Vehicles & Exp	5310	10,505	16,996	12,715	16,040	18,238
Reading-Contract Services	5310	188,701	200,937	209,840	220,092	443,441
Billing-Labour & Expenses	5315	592,909	626,097	608,027	669,677	891,750
Collecting-Lab, Vehicles $ Exp	5320	562,928	648,703	654,195	672,098	757,992
Collecting-Cash Over & Short	5325	335	(64)	(822)	168	2,000
Billing-Bad Debts	5335	39,965	51,800	146,640	161,800	100,000
Billing & Collecting		1,501,889	1,653,517	1,750,464	1,852,686	2,331,264

Billing and Collecting Variances

	US of A	2008	2009	Change 2008-09		2009	2010 Test	Change 2009-10	
	Accounts	Actual	Actual	$	%	Actual		$	%
Bill & Collect - Supervision	5305	119,870	112,813	(7,057)	-5.89%	112,813	117,842	5,029	4.46%
Reading-Labour, Vehicles & Exp	5310	12,715	16,040	3,325	26.15%	16,040	18,238	2,199	13.71%
Reading-Contract Services	5310	209,840	220,092	10,252	4.89%	220,092	443,441	223,349	101.48%
Billing-Labour & Expenses	5315	608,027	669,677	61,650	10.14%	669,677	891,750	222,073	33.16%
Collecting-Lab, Vehicles $ Exp	5320	654,195	672,098	17,903	2.74%	672,098	757,992	85,894	12.78%
Collecting-Cash Over & Short	5325	(822)	168	990	-120.39%	168	2,000	1,832	1092.53%
Billing-Bad Debts	5335	146,640	161,800	15,159	10.34%	161,800	100,000	(61,800)	-38.20%
Billing & Collecting		1,750,464	1,852,686	102,223	5.84%	1,852,686	2,331,264	478,578	25.83%

2008-2009, 2009- 2010 Variances by Account

The following table sets out the Billing and Collecting accounts that exceed materiality:

		2008	2009	2010 Test	Change Between	Change Between
		Actual	Actual		2008-2009	2009-2010
Reading-Contract Services	5310	$209,840	$220,092	$443,441	$10,252	$223,349
Billing-Labour & Expenses	5315	$608,027	$669,677	$891,750	$61,650	$222,073

<u>Reading Contract Services Account 5310</u>

Reading and Contract Services costs in Account 5310 are projected to increase by $223,349 in 2010. The increase can be broken down as follows:

1. ODS $ 56,000
2. Exception reporting $150,000
3. All other changes $ 18,349

Total $223,349

The majority of costs relates to Smart Meters and TOU pricing and are discussed in the 2010 Billing and Collecting Cost Drivers section.

Billing and Collecting Account 5315

Billing and Collecting costs in Account 5315 are projected to increase by $222,073 in 2010. The increase can be broken down as follows:

1. Smart Meter Incremental Costs of $165,000:

Software Maintenance Costs	$ 33,000
Security Audit	$ 23,000
Other- IESO	$110,000

2. Other Cost Drivers	$ 57,073
Total	$222,073

The majority of costs relates to Smart Meters and TOU pricing, and are discussed in the 2010 Billing and Collecting Cost Drivers section.

Administration

		2006	2007	2008	2009	2010 Test
		Actual	Actual	Actual	Actual	
Director's Lab & Expense	5605	147,169	116,555	128,122	125,090	134,102
Administration Labour & Exp	5610	588,016	707,804	681,267	695,426	692,922
Office Labour & Expenses	5615	163,061	310,673	363,922	396,964	436,194
Insurance-Admin Bldgs	5635	79,379	86,267	142,988	136,159	200,140
Regulatory Expense	5655	567,077	405,717	160,459	132,672	326,008
Telephone SC/LD/Eq Rent	5620	166,729	221,309	236,247	260,999	293,544
Outside Services Employed (1)	5630	1,150	0	251,628	250,941	253,970
Admin Bldg-Rental	5670	180,000	278,120	270,000	270,260	270,000
Admin Bldg-Lab & Vehicle	5675	175,422	136,647	139,902	173,862	191,519
Administration Labour & Exp		2,068,003	2,263,092	2,374,534	2,442,373	2,798,398

Administration Variances

	US of A	2008	2009	Change 2008-09		2009	2010 Test	Change 2009-10	
	Accounts	Actual	Actual	$	%	Actual		$	%
Director's Lab & Expense	5605	128,122	125,090	(3,032)	-2.37%	125,090	134,102	9,012	7.20%
Administration Labour & Exp	5610	681,267	695,426	14,160	2.08%	695,426	692,922	(2,505)	-0.36%
Office Labour & Expenses	5615	363,922	396,964	33,043	9.08%	396,964	436,194	39,229	9.88%
Insurance-Admin Bldgs	5635	142,988	136,159	(6,829)	-4.78%	136,159	200,140	63,981	46.99%
Regulatory Expense	5655	160,459	132,672	(27,788)	-17.32%	132,672	326,008	193,336	145.73%
Telephone SC/LD/Eq Rent	5620	236,247	260,999	24,752	10.48%	260,999	293,544	32,545	12.47%
Outside Services Employed	5630	251,628	250,941	(687)	-0.27%	250,941	253,970	3,029	1.21%
Admin Bldg-Rental	5670	270,000	270,260	260	0.10%	270,260	270,000	(260)	-0.10%
Admin Bldg-Lab & Vehicle	5675	139,902	173,862	33,960	24.27%	173,862	191,519	17,657	10.16%
Administration Labour & Exp		2,374,534	2,442,373	67,839	2.86%	2,442,373	2,798,398	356,025	14.58%

(1) prior to 2008 outside services employed to provide regulatory support were recorded in account 5655 regulatory expense.

2008-2009, 2009- 2010 Variances by Account

The following table sets out the Administration accounts that exceed materiality:

	US of A	2008	2009	2010 Test	Change 2009-10	
	Accounts	Actual	Actual		$	%
Insurance	5635	142,988	136,159	200,140	$ 63,981	46.99%
Regulatory Expense	5655	160,459	132,672	326,008	$193,336	145.73%

The following two accounts experienced increases from 2009-2010 that exceeded materiality and they were Insurance and Regulatory Expense.

The increases in these accounts are described in the Administration 2010 Cost Drivers section.

Operations and Maintenance

	US of A Accounts	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Test Forecast
Operation Supervision	5005	0	0	129,802	143,857	180,204
Substn Op'n-Labour	5016	30,426	41,590	69,527	30,287	76,706
O/H Line Operation-Labour	5020	360,155	155,265	31,781	78,209	88,610
O/H Line Op'n-Supplies & Exp	5025	4,103	4,250	63,808	30,473	36,000
O/H Dist Transformer Operation	5035	10,407	13,062	2,691	11,042	16,516
U/G Line Op'n-Labour	5040	245,578	234,898	201,046	285,311	328,516
U/G Line Op'n-Supplies & Exp	5045	11,138	18,583	16,218	11,320	19,000
U/G Dist Transformer Operation	5055	64,809	49,377	67,291	69,192	71,923
Dist Meters-Reverification	5065	144,694	179,277	129,174	168,323	170,564
Customer Premises	5070	95,252	108,953	130,882	165,361	167,546
Engineering & Ops Training	5080	37,091	31,254	12,940	10,798	13,488
O/H Lines Op-Rentals Paid	5095	20,793	20,813	20,832	21,387	23,000
Substation Maintenance	5114	14,674	42,853	59,591	68,941	67,186
O/H Line Mtce-Poles	5120	253,927	233,316	61,631	196,375	224,339
O/H Line Mtce-Conductor	5125	253,313	280,870	305,044	375,209	399,829
Tree Trimming & ROW Mtce	5135	56,661	62,724	177,506	123,206	177,236
U/G Line Mtce-Conduit	5145	41,016	19,023	12,033	32,384	35,961
U/G Line Mtce-Cable	5150	170,189	315,390	232,606	249,982	306,158
Dist Transformer Mtce	5160	48,195	50,185	80,111	96,103	100,597
Dist Meter Maintenance	5175	(1,465)	33,308	26,625	40,267	56,849
Operation & Maintenance		1,860,955	1,894,991	1,831,140	2,208,026	2,560,224

Operations and Maintenance Variances

	US of A	2008	2009	Change 2008-09		2009	2010 Test	Change 2009-10	
	Accounts	Actual	Actual	$	%	Actual		$	%
Operation Supervision	5005	129,802	143,857	14,055	10.83%	143,857	180,204	36,347	25.27%
Substn Op'n-Labour	5016	69,527	30,287	-39,240	-56.44%	30,287	76,706	46,419	153.26%
O/H Line Operation-Labour	5020	31,781	78,209	46,428	146.09%	78,209	88,610	10,401	13.30%
O/H Line Op'n-Supplies & Exp	5025	63,808	30,473	-33,335	-52.24%	30,473	36,000	5,527	18.14%
O/H Dist Transformer Operation	5035	2,691	11,042	8,351	310.29%	11,042	16,516	5,474	49.57%
U/G Line Op'n-Labour	5040	201,046	285,311	84,265	41.91%	285,311	328,516	43,205	15.14%
U/G Line Op'n-Supplies & Exp	5045	16,218	11,320	-4,898	-30.20%	11,320	19,000	7,680	67.84%
U/G Dist Transformer Operation	5055	67,291	69,192	1,901	2.83%	69,192	71,923	2,731	3.95%
Dist Meters-Reverification	5065	129,174	168,323	39,149	30.31%	168,323	170,564	2,241	1.33%
Customer Premises	5070	130,882	165,361	34,479	26.34%	165,361	167,546	2,185	1.32%
Engineering & Ops Training	5080	12,940	10,798	-2,142	-16.55%	10,798	13,488	2,690	24.91%
O/H Lines Op-Rentals Paid	5095	20,832	21,387	555	2.67%	21,387	23,000	1,613	7.54%
Substation Maintenance	5114	59,591	68,941	9,350	15.69%	68,941	67,186	-1,755	-2.55%
O/H Line Mtce-Poles	5120	61,631	196,375	134,744	218.63%	196,375	224,339	27,964	14.24%
O/H Line Mtce-Conductor	5125	305,044	375,209	70,165	23.00%	375,209	399,829	24,620	6.56%
Tree Trimming & ROW Mtce	5135	177,506	123,206	-54,300	-30.59%	123,206	177,236	54,030	43.85%
U/G Line Mtce-Conduit	5145	12,033	32,384	20,351	169.13%	32,384	35,961	3,577	11.05%
U/G Line Mtce-Cable	5150	232,606	249,982	17,376	7.47%	249,982	306,158	56,176	22.47%
Dist Transformer Mtce	5160	80,111	96,103	15,992	19.96%	96,103	100,597	4,494	4.68%
Dist Meter Maintenance	5175	26,625	40,267	13,642	51.24%	40,267	56,849	16,582	41.18%
Operation & Maintenance		1,831,140	2,208,026	376,887	20.58%	2,208,026	2,560,224	352,198	15.95%

2008-2009 Variances by Account

The following table sets out the Operations and Maintenance accounts that exceed materiality:

The following two accounts experienced increases from 2008-2009 that exceeded materiality: U/G Line Operation Labour and Overhead line Maintenance.

	US of A	2008	2009	Change 2008-09	
	Accounts	Actual	Actual	$	%
U/G Line Op'n-Labour	5040	201,046	285,311	84,265	41.91%
O/H Line Mtce-Poles	5120	61,631	196,375	134,744	218.63%

<u>U/G line operational labour</u>

The Applicant reallocated maintenance resources back to this account in 2009 and 2010 to ensure overall reliability, safety and cost effectiveness. The yearly average in this account from 2002 to 2007 was approximately $230,000. In 2008 underground maintenance was superseded by capital work. In 2009 and 2010 the Applicant is experiencing an ever increasing number of underground faults which are requiring immediate attention. The Applicant expects this trend to continue due to an ever increasing amount of underground lines and the age of the plant.

<u>Overhead Line Maintenance</u>

The Applicant has reallocated resources back to Overhead Line Maintenance in 2009 and 2010 to ensure overall line reliability, safety and cost effectiveness. In 2008 overhead maintenance was superseded by capital work. The normal yearly average (2003 to 2007) in this account was $190,000.

Exhibit 4: Operating Costs

Tab 4 (of 8): Employee Compensation

STAFFING AND COMPENSATION LEVELS

Employee Compensation

This section describes the staffing and compensation levels at the company, any incentive pay plans or pension requirements. The following tables provide a summary of total annual compensation costs and average compensation levels per FTE for 2008, 2009 and 2010.

Number of Employees (FTEs including Part-Time)	2008	2009	2010
Executive	7	7	7
Management	10	10	11
Non-Union	15	15	15
Union	21	22	23
Total	53	54	56
Total Salary and Wages			
Executive	710,492	731,807	753,759
Management	889,629	915,134	1,063,418
Non-Union	744,618	762,324	786,334
Union	1,793,112	1,929,765	2,006,995
Total	4,137,851	4,339,030	4,610,506
Total Benefits			
Executive	139,981	145,141	152,669
Management	189,797	192,230	228,272
Non-Union	201,137	211,938	220,429
Union	367,744	399,352	433,124
Total	898,659	948,661	1,034,494
Total Compensation (Salary, Wages, & Benefits)			
Executive	850,473	876,948	906,428
Management	1,079,426	1,107,364	1,291,690
Non-Union	945,755	974,262	1,006,763
Union	2,160,856	2,329,117	2,440,119
Total	5,036,510	5,287,691	5,645,000
Compensation - Average Yearly Base Wages			
Executive	101,499	104,544	107,680
Management	84,563	87,113	92,220
Non-Union	49,641	50,822	52,422
Union	70,372	71,648	73,032
Total	71,293	72,991	75,612
Compensation - Average Yearly Overtime			
Executive			
Management			
Non-Union			
Union	15,015	16,068	14,228
Total			
Compensation - Average Yearly Incentive Pay			
Executive			
Management	4,400	4,400	4,455
Non-Union			
Union			
Total			
Compensation - Average Yearly Benefits			

Executive	19,997	20,734	21,810
Management	18,980	19,223	20,752
Non-Union	13,409	14,129	14,695
Union	17,512	18,152	18,831
Total	16,956	17,568	18,473
Total Compensation	5,036,510	5,287,691	5,645,000
Total Compensation Charged to OM&A	3,308,987	3,529,170	3,725,700
Total Compensation Capitalized	1,727,523	1,758,521	1,919,300

Wage Increases

The Applicant has settled a union contract, which expires March 2012, that includes a 3% increase in wages per annum. Therefore salary increases are and assumed to be 3% per annum.

Variances in Staffing Levels

The Applicant has hired two Cambrian College Powerline Technicians. One in 2009 and another January 1, 2010. The Applicant is also expecting to hire an additional engineer in 2010 for asset management and to manage the Electrical Safety Standards for The Applicant. Greater detail on these positions is described in the Operations and Maintenance cost driver section above. The Applicant is not expecting any retirements or any additional hiring during the IRM period.

Exhibit 4: Operating Costs

Tab 5 (of 8): Corporate Cost Allocations

SHARED SERVICES & CORPORATE COST ALLOCATIONS

The Applicant does not share services with any affiliates.

Exhibit 4: Operating Costs

Tab 6 (of 8): Purchase of Non-Affiliate Services

PURCHASES OF NON-AFFILIATE SERVICES

As a component of the Applicant's OM&A expenses, it is forecasted that in 2010 various goods and services totaling $2.968 million will be purchased from third-parties. Over 60 percent of these costs are related to five major purchases: Olameter ($630K), MEARIE ($536), Elenchus/Ogilvy ($239K), Canada Post ($235K), Utility Line Clearing ($160K) and Jerry Kunsch Excavating Ltd ($101K).

The Applicant contracted with Olameter to ensure that it can efficiently and accurately provide a number of key customer service functions including meter reading billing, collections, processing scanning printing, envelop stuffing and mailing. The payments to MEARIE are required to provide cost effective benefits to The Applicant's employees ($336K) and competitive insurance coverage for the utility ($200K). Consulting and legal costs were incurred to prepare and support the Applicant's rebasing application. These costs were forecast to be $157 and $82K in the rate application and may need to be revised depending on the complexity of the settlement and hearing processes.

Postage is an unavoidable expenditure as long as customers continue to prefer to have their bills mailed to them directly. These costs are forecast to increase in line with the price increase from Canada Post. The Utility Line Clearing cost is related to the activities required to ensure safe reliable distribution service, which include tree trimming, insulator washing and qualified linemen. The excavation costs were also unavoidable being driven by fault frequency and the need to repair and replace underground cables to maintain distribution service.

A copy of The Applicant's Procurement Policy is attached.

The table below provides further detail on the actual expenditures for third parties transacting with The Applicant in the years 2008-2009 for total services in excess of $30K. The 2010 amounts are forecasted.

Table of Purchases by Supplier

Vendor	2008	2009	2010	Nature of Expense Process
ACUMEN ENGINEERED SOLUTIONS	35,482	33,866	35,000	Engineering Services - *3 Year Competitive Tender*
A.G.O. INDUSTRIES INC.	36,478	38,056	36,000	Work Clothing - *3 Year Competitive Tender*
AUTOMATED SOLUTIONS INTL	33,968	47,236	40,000	ASI Application - *5 Year Competitive Tender*
BLACK & MCDONALD LIMITED	53,311	53,466	54,000	Substation Maintenance - *5 Year Competitive Tender*
BRAY'S FUELS	34,104	44,602	40,000	Diesel Fuel Purchase - *5 Year Competitive Tender*
CABLE MASTER INC.	39,880	34,072	40,000	Stakeouts - *3 Year Competitive Tender*
CANADA POST CORPORATION	187,949	205,925	235,000	Mailing Services
CARLOS SILVA PARTS&SERVICES	-	37,488	40,000	Misc Supplies - *3 Year Competitive Tender*
CAYENTA CANADA CORP	45,264	48,885	47,000	Financial System Support - *Contingent on Financial System*
COLLINS BARROW	55,810	65,000	71,000	External Audit Services - *5 Year Competitive Tender*
ELECTRICITY DISTRIBUTORS ASSO(	52,028	53,760	55,000	Annual Dues
ELENCHUS RESEARCH ASSOC.	-	156,815	60,185	Rate Filing Consulting
GALLOWAY MOTORS LTD.	23,732	31,789	31,000	Large Vehicle Repair - *5 Year Competitive Tender*
HARRIS	31,025	32,775	34,000	Customer Service System Support - *Contingent on Financial System*
HILL-SAN AUTO SERVICE	27,475	29,243	30,000	Small Vehicle Maintenance - *5 Year Review*
IDEAL SUPPLY COMPANY LTD	56,580	48,125	50,000	Misc Inventory - *5 Year Competitive Tender*
JERRY KUNSCH EXCAVATING LTD.	92,486	101,299	103,000	Underground Excavating - *3 Year Competitive Tender*
KABAR INDUSTRIES LTD.	26,831	27,531	30,000	Misc Supplies - *5 Year Competitive Tender*
McCARTHY TETRAULT LLP	65,402	74,372	61,000	Legal Services - *Experts in Field*
MEARIE MANAGEMENT INC.	319,022	336,036	352,000	Benefits - *5 Year review*
MEARIE MANAGEMENT INC.	125,351	136,571	200,140	Insurance Costs - *5 Year review*
NAVIGANT CONSULTING LTD.	13,443	54,314	35,686	TOU Research / Rate Filing
OGILVY RENAULT	-	41,972	82,190	Rate filing - *Experts in Field*
OLAMETER INC.	524,971	629,911	690,000	Meter Reading, Billing, Collecting & Mailing Services - Constant On-going Review
KTI			114,000	Electronic meter reading
THE RICHARDSON TEAM	40,746	21,692	20,000	Misc Consulting
SAVAGE DATA SYSTEMS	58,604	72,982	115,000	Settlement Services
SUNCOR ENERGY	39,176	38,140	42,000	Fuel Purchase - *3 Year Review*
UTILITY LINE CLEARING	166,165	120,000	160,000	Line Clearing and Insulator Washing - *3 Year Competitive Tender*
WESTBURNE RUDDY ELECTRIC	66,413	67,884	65,000	Misc Supplies - *5 Year Competitive Tender*

Attachment 2 (of 2):

Purchasing Policy

Newmarket – Tay Power Distribution Ltd. STANDING INSTRUCTION	S.I. NUMBER: 100-003 ISSUE DATE: October, 2002 LAST REVIEWED: November, 2008 REVIEW DATE: January 2010 ORIGINATED BY: Administration
TITLE PURCHASING POLICY	

1. Corporate Purchasing Policy

Newmarket – Tay Power Distribution Ltd. ("NT Power") will maintain an open and competitive process with respect to the purchase of goods and services and actively investigate new sources and methods of procurement for products and services to provide the most effective and efficient services.

2. Goals and Objectives for Departments

To direct their activities toward the corporate purchasing policy, the goals and objectives of all departments in the purchasing of goods and services are as follows:

1. establish clear and objective specifications for all purchases,
2. assist in identifying potential sources for purchases,

1. recommend sole source justification in accordance with the policies,
4. select successful bidders and suppliers,
5. make recommendations to the Board with respect to the award of tenders as required by the policies and procedures,
6. designate persons authorized to approve expenditures and their expenditure limits within their department,
1. review purchases upon delivery to ensure compliance with specifications,
8. comply with the approved purchasing policies and procedures of the NT Power,
9 ensure the timely and efficient procurement of quality goods and services for the needs of NT Power,
1. develop and maintain reliable sources of supply,
1. obtain competitive bids,
1. negotiate major contracts,
1. create and ensure standards of quality, safety and compatibility.

3. Green Procurement Policy

Reduce, Reuse, Recycle and Recover Methodology

At each phase of the life cycle of goods and materials departments shall apply the reduce, reuse, recycle and recover methodology.

3.1 Review of Needs Prior to Sourcing Goods and Materials

Before deciding to the need to acquire any goods and services, NT Power shall:

a) Review whether other options for meeting the needs of NT Power have been explored.

b) Examine the feasibility of short-term rental or sharing the product as an alternative to purchasing.

c) Review whether the quantity requested is appropriate.

d) Determine whether the product will be completely used at the end of its cycle and if not, whether it may be easily reallocated.

e) Ensure that all new products and materials not previously purchased by NT Power being considered for use are subject to a Risk Analysis Assessment prior to purchase.

3.2 Review of Goods and Material Prior to Purchase for Environmental Impacts

When seeking written quotations or tenders for the purchase of goods or materials, NT Power will request information from the vendor to demonstrate how the product meets the criteria listed below. When selecting materials or goods for purchase without the submission of written quotations or tenders, NT Power will conduct its own examination of the goods to determine whether the criteria have been met. The vendor will also be requested to propose alternate green solutions.

3.3 Product or Material Characteristics

a) Certified by the Environmental Choice Program
b) Designed to minimize waste
c) Energy efficient or included in the Energy Guide labeling program
d) Less polluting than competitive products
e) Free from hazardous ingredients that would require special disposal
f) Free from resources that come from environmentally sensitive regions (i.e. contains no lumber from tropical rainforests such as some teak or mahogany)
g) Free from banned or restricted substances such as CFCs, benzene or arsenic
h) Is manufactured from recycled materials including a high percentage of post-consumer recycled content

3.4 Packaging

a) Packaging is designed to minimize waste such as bulk packaging
b) Packaging is reusable by the end-user
c) Packaging is accepted by the supplier for reuse, recycling or recovery
d) Packaging is recyclable locally

e) Packaging is made from recycled materials

3.5 Operational Characteristics of Product Or Material

a) Durable with a long service life
b) Clear and comprehensible operating instructions to ensure that it is used efficiently
c) Easy to maintain in good operating condition, economical to repair and easy to upgrade
d) Reusable or includes reusable parts such as rechargeable batteries

3.6 Disposal After Use

a) Suitability of the product or its components for use by other departments instead of being disposed of.
b) Ability to return to the supplier for reuse, recycling or recovery.
c) Eligibility for contribution to a waste exchange program.
d) Ability to recycle the product locally.
e) Eligibility for donation to other organizations.

4. Definitions

"Goods and services" shall include all supplies, materials, general maintenance, equipment and service contracts, consultants' services, and construction contracts and shall not include the purchase or sale of land or buildings.

"Value" of a lease or rental shall be determined by multiplying the monthly payment by the number of months contained in the lease.

5. Competitive Purchasing Process Requirements

NT Power will advertise annually to solicit names of suppliers that may wish to provide products and services. NT Power will maintain a list of names of the suppliers received until the next advertisement is issued.

6. Budgeted Purchases

Purchases must be provided for in the budget of the current year and adhere to the following schedule of approvals:

a) up to $5,000 by the Line Superintendent or General Foreperson

b) in excess of $5,000 up to $10,000 by the Manager of Technical Services, the Office Manager or Customer Service Manager

c) in excess of $10,000 up to $25,000 by the Director of Technical Operations

d) in excess of $25,000 by the Chief Financial Officer and the President or Chief Operating Officer.

In the event a purchase should cause the budget category to be overspent by more than 10%, the purchase amount must be approved by the Board of Directors of NT Power.

In the event a purchase should cause the budget category to be overspent up to 10%, the purchase may be approved by the Chief Financial Officer and the President or Chief Operating Officer, provided the amount is found elsewhere within the global budget.

Staff shall, under non-emergency situations, obtain competitive quotations, and in any event, where the expenditure is to exceed $10,000, at least three competitive quotations must be obtained except as set out in Clause 16.

All expenditures in excess of $250,000 will be subject to a sealed tender process whereby the subject tenders will be opened, reviewed, and selected at a normal Board of Director=s meeting.

No transfers from capital expenditures to operating expenses to be undertaken unless approved by the Board of Directors of NT Power.

Notwithstanding the foregoing, the President, Chief Financial Officer or Chief Operating Officer may authorize expenditures in the case of an emergency.

1. Non-Budgeted Purchases

Purchases not provided for in the budget of the current year may be approved by the Chief Financial Officer and the President or Chief Operating Officer up to $25,000, provided the amount is found elsewhere within the global budget.

2. Purchases when only one Bid is Received

When only one bid is received on a tender or RFP, a decision will be made by the President, Chief Financial Officer or Chief Operating Officer as to whether the bid shall be opened or returned to the bidder unopened. The Purchasing or user department shall investigate the rationale for receiving only one (1) bid. If a new bid call is deemed appropriate, it should be due to a change in the specification, which may have limited bid participation.

9. Consultant Selection Process

The selection and retention of consultants for projects shall be undertaken in accordance with the procedures in this section and shall be subject to all other procedures in this policy document including competitive pricing processes.

9.1 Objective

The objective of these guidelines is to ensure that the process used in the selection of consultants represents the following principles and values:

a) A consistent and uniform process for selecting consultants should apply throughout NT Power; there should be fair and equitable access by all qualified consultants to respective assignments;

b) The selection process should be open and clearly documented;

c) Consulting assignments should be awarded primarily on the basis of competence and expertise. Price should be included in the evaluation process as a measure of cost/benefit but should be only one of a number of criteria used in assessing the proposals; and,

d) The consultant selection process needs to be cost-effective with respect to staff costs to administer it and consultants' costs to prepare and submit proposals.

9.2 One Time Project/Assignment (Consultants for a Capital Project or a Specific Study)

The opportunity will be advertised to known Consultants. Bidders meeting may be necessary to confirm requirements.

Proposals are submitted in writing to NT Power. Quality and technical criteria are evaluated. Fees may be submitted separately. Pre-bid meetings are held, if required, to confirm the scope of the project.

a) The first step is to assess the technical/quality criteria that may vary from project to project but should encompass an assessment of factors related to the firm being evaluated and the nature of the assignment.

b) The three (3) highest overall technical/quality criteria score proceed for further evaluation.

c) The proponent with the highest overall weighted score is recommended for selection.

9.3 Repetitive Projects/Assignments (Consultants for Continuous Service)

The following process shall govern the retention of consultants to provide services to NT Power on an ongoing basis, or on a long term multiple basis, for periods not to exceed three years.

When NT Power is engaging the services of a consultant on a long term or continuous basis, expressions of Interest shall be requested through correspondence to firms on NT Power 's register who have had prior related experience with the organization.

Expressions of interest are evaluated based on broad, company-specific criteria. The broad criteria may vary from project to project but should encompass an assessment of the following factors related to the firm being evaluated:

a) experience and performance on similar projects
b) local knowledge
c) professional reputation and integrity
d) stability and reputation of firm
e) multi-disciplinary/specialty capabilities
f) quality assurance system

A short-list of three to six is generated from the companies receiving the top scores from the broad criteria evaluation process. Requests for detail proposals are made to the short-list. Meetings are held, if required, to confirm the scope of the project

Proposals and fees are submitted in writing. Quality and technical criteria are evaluated. Fees, submitted separately, are evaluated only after qualified firms have been identified.

The evaluation criteria at this stage would include:

Project Manager
Technical support staff
Sub-consultants or partners
Experience on similar projects
Availability of key staff
Stability and reputation of the firm
Multi-disciplinary/specialty capabilities
Quality assurance system

When assignments become available, those firms specializing in the type of assignment at hand form a pre-qualification list for the assignment. Firms requested to submit proposals are selected on the basis of the firm's experience with similar projects; the firm's location relative to the job location; and the volume of work currently undertaken by that firm for other NT Power assignments, among other criteria that may be specific or relevant to the project at hand.

The list will also contain history on other proposals submitted by the consultant and any sub-consultants they have identified.

10. Purchase Requisition

The purchase requisition starts the procurement process and is used to acquire materials, supplies, equipment or services. It is also used to request the establishment of a Contract Purchase Order to handle the repetitive purchase of services or products. The Purchase Requisition is a two (2) part form with a pre-printed number. The requisitioning department should retain the copy for future enquiries and the original white copy should be forwarded by interoffice mail to the Accounting Office for processing.

The requisitioning department is responsible for providing all supporting documents such as specifications, sole source justification, a complete G/L number, and appropriate approval signatures attached to the requisition.

Departments should anticipate their requirements to allow adequate lead-time for tender/quotation, order processing and product delivery. Item descriptions should be complete and accurate to allow buyers to bid the requirements expeditiously.

11. Requests for Tenders/Bids/Quotations/Proposals

The purchasing Department is responsible for obtaining all quotations, issuing all requests for proposals and tenders for goods and services.

The submission of split requisitions in an attempt to circumvent the bidding policy is not allowed.

The purchasing Department may, at its discretion, contact other bidders other than the apparent lowest bidder for the purpose of seeking information, conducting interviews or requesting clarification of their submission.

12. Insurance

12.1 Contractors Risk

The Contractor shall assume full responsibility as to public safety, public liability and property damage, and warrants that his workmen shall be covered by Worker's Compensation (see also Section 1.4 "Insurance"). The Contractor shall be a member in good standing of the Electrical Utilities Safety Association of Ontario (EUSA). Personnel working for the Contractor shall work in a safe manner at all times and abide by the requirements of the EUSA rule book and appropriate Safe Practice Guide and be competent personnel who are qualified by knowledge, training and experience to work within 3 metres of lines and equipment that is energized at voltages up to and including 44KV for the purpose of performing the work.

In addition, work will conform to the requirements of the Occupational Health and Safety Act, and the regulations under this Act as well as to NT Power's standards. In order to avoid any misunderstanding as to the nature of the work to be performed herein, the Contractor, by executing this contract unequivocally acknowledges that he is the "Constructor" within the meaning of the Occupational Health and Safety Act and amendments thereto. The Contractor shall comply with relevant federal, provincial and municipal statutes, regulations, bylaws and codes which apply to the work and its performance, and shall obtain and pay for all work permits that may be required for the performance of the work.

In the event of any lawsuits or charges under the Occupational Health and Safety Act arising from a worker related accident on the job site, the Contractor shall compensate Newmarket Hydro for any and all time required to prepare for and attend any hearings and for all legal fees and the fees of expert witnesses to defend these lawsuits or charges.

12.2 Workers' Compensation

The Contractor shall provide prior to commencement of any works the following Occupational Health and Safety related information:

a) Their own and any subcontractors' Occupational Health and Safety policies.

b) Their own and any subcontractors' CAD7 experience rating records from W.I.C.B. as well as a Clearance Certificate.

NT Power reserves the right to withhold payment of the contract price pending W.I.C.B. confirmation that the contractor has paid all assessments.

12.3 Insurance

The Contractor at all times during the course of the work shall indemnify and save harmless NT Power, the Town of Newmarket and the Township of Tay as applicable from and against all claims, damages, losses and demands whatsoever and howsoever arising from any action taken by the contractor, his agents, subcontractors or transferee and undertakes to accept full responsibility for all such actions and in this respect shall purchase and maintain in force, during the course of the work, insurance against public liability and property damage (including the property of NT Power) in the amount of $2,000,000.00. Insurance certificates showing NT Power, the Town of Newmarket, The Region of York, the Township of Tay and the County of Simcoe, as applicable as named insured shall be submitted prior to any work being performed.

12.4 WHMIS - Workplace Hazardous Materials

The Contractor is responsible to provide training and necessary equipment to the Contractor's employees for the handling of hazardous materials.

The Contractor is responsible for making sure all hazardous materials have proper supplier labels and that up to date (less than 3 years old) material safety data sheets (M.S.D.S.) are available to the owner at the work site, for all products which are hazardous materials in the contract and/or on the construction site.

1. Confidentiality of Bids/Quotations/Proposals

In accordance with fair and sound business practice, all information supplied by vendors in their bid, quotation or proposal will be held in strict confidence.

2. Late Bids/Quotations/Proposals

Late bids, quotations and proposals will not be considered.

15. Errors in Bids/Quotations/Proposals

Vendors are responsible for the accuracy of their quoted prices, in the event of an error between a unit price and its extension, the unit price will govern. Quotations may be amended or withdrawn by the bidder up 'to closing date and time@ in writing by the signing officer of that company.

16. Sole Source Procurement (See also Emergency Order - Clause 20)

Sole source items require detailed documentation from the requisitioning department to justify their purchase and to ensure that the cost charged by the vendor is reasonable.

Sole Source Suppliers may be used in the following instances:

a) when products or services can be obtained only from one (1) person or firm, or the

b) expertise of an individual organization or individual is deemed to specifically required by NT Power,

c) when competition is precluded because of the existence of patent rights, copyrights secret processes, control of raw material or other such conditions,

d) when it is the only product or service that has been approved by NT Power for use in the distribution system, when the procurement is for electric power or energy, gas, water or other utility services where it would not be practical to allow a contractor other than the utility company itself to work upon the system,

f) when the procurement is for technical services in connection with the assembly, installation or servicing of equipment of a highly technical or specialized nature,

g) when the procurement is for parts or components to be used as replacements in support of equipment specifically designed by the manufacturer,

h) the contractor is already at work on the site (based on an existing Purchase Order) and it would not be practical to engage another contractor,

i) Health and Safety.

2. Demonstration Equipment and Sample Material

Vendors who supply demonstration equipment or sample material to departments must be advised by the department to provide their own insurance coverage. If the department is interested in purchasing the demonstration equipment or sample material, the normal Purchasing procedure must be followed.

3. Approvals for Construction and Alterations to Physical Space

All requisitions for construction, renovation or alteration to physical space at NT Power facilities require the review and prior written approval of the Manager responsible for the facility. Detailed specifications, drawings and/or blue prints, if appropriate, should accompany the Purchase Requisition.

19. Procurement Cards

NT Power has delegated some low value purchasing to user departments through a procurement card program, to provide an efficient and effective means with which to make purchases of small value, or that are repetitive.

20. Emergency Order

An emergency shall be defined as any situation which, if not corrected immediately, would result in a hazard to persons or property, create improper working conditions could result in damage to buildings or facilities, would result in a violation of law, statute or ordinance established by governmental regulation, or in any other fashion, if not acted upon, would be seriously detrimental to the interest of NT Power or its customers.

Failure to anticipate a need is not, of itself; considered a valid emergency. Emergency orders are generally used for repairs.

The President, Chief Financial Officer or Chief Operating Officer may authorize any expenditure in the case of an emergency.

If an emergency purchase is made by a department during non business hours, all supporting documentation must be forwarded to the appropriate approval authority the next business day, in order that a Purchase Order may be issued to the vendor.

21. Change Order--Cancellation or Modification of Order

Changes in a previously issued Purchase Order can be made only by a Change Order. This does not apply where the goods or services are being provided under a contract that contains provisions for the issuance of change orders in which case the terms of that contract shall govern the process.

The changes may refer to price, quantities ordered, terms and conditions, delivery point, etc. As a result of these or any other changes, the accounting information may also have to be altered.

A Change Order is generated by the requisitioning department and forwarded to the vendor in the form of a letter or memorandum.

22. Leases/Lease Purchase and Rental Agreement

The policies governing the purchase of goods and services shall also apply to lease and rental agreements. All forms of Leases, Lease Purchases or Rental Agreements for the procurement of equipment must be signed on behalf of the NT Power by a Corporate Officer, and in the case of tenders or contracts approved by the Board, they must also contain a reference to the appropriate Board Resolution.

Regardless of the time period involved in these agreements, a formal Purchase Order will be issued. Departments should fully describe the equipment to be leased and indicate the proposed term (number of months or years).

An analysis will be made to determine the economic soundness of whether the goods should be leased or purchased in cooperation with the CFO.

Some of the factors which will be considered in making this determination are as follows:

a) Title to the equipment at the end of the lease
b) Estimated value of the equipment at the end of the lease
c) Estimated life of the equipment at the end of the lease
d) Estimate buy-out value at the end of the lease.

23. Terms and Conditions

Terms and conditions governing the purchase of goods and services are printed on NT Power's Purchase Order that is sent to vendors. When a separate
contract is required, it must accompany the completed Purchase Requisition in order for the requisition to be processed.

24. Computer Equipment

Departments requiring the acquisition of microcomputer and peripheral equipment should contact the Information Technology Manager for instruction, research and for assistance in system configuration. The IT Manager shall prepare the appropriate specifications for use in obtaining competitive pricing.

25. Receiving / Signing for Shipments/Services

25.1 Receiving Material

Verification of shipments from vendors and the receipt of proper documentation such as freight bills, bills of lading, packing slips containing the purchase order number, shipping orders or other documentation are the responsibility of the department receiving the goods or services. Services from contractors or vendors such as HVAC, electrical and refrigeration service or maintenance should be documented by a work sheet containing the details of the services provided, pricing and the purchase order number. It is preferred that the staff member who arranged for this service signs this work sheet. Staff shall ensure that the work order is completely filled out with pricing and purchase order number before signing.

25.2 <u>Procedure</u>

a) Examine the shipment (count, weigh or measure merchandise, as applicable) to assure all items are in good condition. Notify Purchasing of damaged merchandise, shortages, incorrect shipments, etc.

b) Inspect Vendor's documentation for quantities, pricing and purchase order number and compare with purchase order copy.

c) Sign document as confirmation of receipt for the vendor's representative or truck driver, if any is required.

d) The signed packing/delivery/work order slips including the purchase order number shall be sent immediately to the Accounting Office.

25.3 <u>Toxic / Hazardous Items</u>

Items such as chemicals, a Material Safety Data Sheet (MSDS) must be received with the order and is filed in the user facility WHMIS binder. If the order is sent without a MSDS sheet have the vendor fax the MSDS sheet immediately. These items should be stored separately in appropriate containers or cabinets.

26. Damages, Shortages, Mistakes in Shipping or Invoices and Returns for Credit

In the case of visible damage or shortage for goods received a written notation must be made on the carrier’s delivery receipt **<u>at time of</u>**

delivery. A copy of this delivery receipt shall be directed to the purchasing Department for follow up with the vendor.

In case of concealed damage or shortage of shipment, the goods should be set aside and a written notation concerning the damage/shortage made on the packing slip and **reported immediately to the purchasing Department,** including 'the following details: Purchase Order number, date, vendor and extent of damage or shortage. Claims must be filed immediately. Failure to comply may result in the claim being denied.

27. Local Preference

NT Power will award proposals for goods and services by giving preference to contractors located in Newmarket, when in all other respects, proposals are equal and there is no material difference in cost.

28. Conflicts of Interest

Acquisitions from a business in which a Corporate employee or family member have an interest, is prohibited unless full disclosure of the background facts are presented in writing to the Board of Directors of NT Power.

29. Code of Conduct for NT Power Employees

NT Power’s employment policies outline a code of conduct that apply to all employees and their business relations with individuals and organizations that conduct business with the company.

1. Confidentiality and Right to Audit

All contracts for services in which the contractor will or may have access to confidential information shall contain NT Power's confidentiality and right to audit clauses.

31. Personal Purchases by Employees

Pricing arrangements negotiated by NT Power may be made available to officials and employees of NT Power at the discretion of a Corporate Officer. However, any such purchase by staff shall be invoiced directly to the staff member. No personal purchases made by an employee or official shall be included on any invoice to NT Power regardless of whether the employee reimburses NT Power for the cost.

32. Charge Accounts

No credit card or charge accounts, other than those sponsored by NT Power (e.g., the Visa Purchasing Card) can be opened.

Date Approved	P. D. Ferguson - President

SERVICES EXCHANGED WITH AFFILIATES

The Applicant entered into transactions with its majority parent, Newmarket Hydro Holdings Inc (NHHI) which is 93% owner of the Applicant ("the Parent") and with The Town of Newmarket which is the sole shareholder of NHHI ("the Shareholder"). These transactions include services provided to the Shareholder and services purchased from the Parent and the Shareholder.

Rent - The Applicant rents Shareholder-owned property (head office and operations center) required for the provision of distribution services. The amount of rent paid to the Shareholder was reviewed by a third party valuator in 2007 to ensure that the rent charged was prudently incurred. The Applicant supplied evidence to that effect in its 2007 application (attached as appendix). The same level of rent is proposed for the test year.

The Applicant incurs property tax on its distribution sites and assets

Services provided to the Shareholder are at the Applicants full cost and the same level of cost that it charges other parties for similar services. Energy sales are priced at Board approved rates.

The Applicant provides full street lighting services to the Shareholder-owned street light system. The services include inspections, pole and bulb replacement. The maintenance services are billed separately at the Applicant's full cost and the associated revenues reduce the overall cost of operating the distribution network.

Interest paid on the debt financing from the Parent and the Shareholder is charged at OEB approved deemed debt rate.

The actual transactions for 2008 and 2009 are shown in the table below along with the amounts forecasted for 2010.

Revenue	**Relation to Applicant**	**2008 $**	**2009 $**	**2010 $**
Energy Sales	Shareholder	2,261,180	2,423,241	2,500,000
Services - Street light	Shareholder	405,491	420,365	457,000
Expenses				
Interest	Shareholder/Parent	1,375,000	1,452,333	1,505,234
Rent	Shareholder	270,000	270,000	270,000
Property tax and other	Shareholder	104,908	107,148	110,000

CUSHMAN & WAKEFIELD LEPAGE

16630 Bayview Ave., Ste 6
Newmarket, ON L3X 1X2
Phone: (905) 841-2500
Fax: (905) 895-3617

June 11, 2007

Mrs. Lorraine Thivierge
Newmarket Hydro Ltd.
590 Steven Court
Newmarket, ON
L3Y 6Z2

Dear Lorraine:

Re: Rental Value – 590 Steven Court, Newmarket

Please find attached a list of current available industrial space in Newmarket and Aurora in excess of 10,000 square feet. Good space with a high percentage of finished office is fairly scarce. Rental rates are mainly over $6.00 per square foot Net with a small percentage of office and the tenant pays all additional costs for property taxes, maintenance, management and insurance (generally around $3.00 PSF). Net lease rates have been fairly flat over the last few years.
Industrial land values are currently in the range of $375,000 to $400,000 per acre with some upwards pressure.

The Newmarket Hydro building located at 590 Steven Court has a gross floor area of approximately 38,396 square feet plus surplus land of approximately 1.5 acres. It would be my opinion, as of today's date, that the building would have a fair market rental value of between $6.00 and $6.50 per square foot Net based on the gross floor area – this would equal total yearly rent of $230,000 to $250,000 Net to the Landlord. I believe a fair market rental value for the surplus land would be $30,000 to $36,000 per annum – this represents something in the range of a 5% to 6% return on the value of the land. Total fair market Net rental, in my opinion, would be in the range of $260,000 to $286,000 per year.

Please note that this is an opinion of value only and should in no way be construed as appraisal. Please call me if I can be of further assistance.

Sincerely,
Cushman & Wakefield LePage Inc.

R Lassaline

Robert Lassaline
Senior Sales Representative

Industrial Space Available
Newmarket
May 2007

10,000-20,000 Sq.Ft.

Size (Sq. Ft.)	Address	Freestand or Multi-Unit	Type	Loading Doors	Price	Comments
11,350	1145 Nicholson Rd # 1A	Multi	Lease	1 TL, 1DI	6.45/sf Net + 2.85 TMI	Half of unit is finished showroom type space Plant is 26' Clear Height
11,924	1124 Stellar Dr # 1&2	Multi	Lease	1 DI	6.50/sf Net + 2.99 TMI	1/3 offices on two floors, 16' clear ht ceilings
12,160	220 Pony Dr # 4&5	Multi	Lease	1 TL, 1 DI	6.50/sf Net + 2.99 TMI	18' clear ceilings, Landlord will put new carpet and paint offices
12,254	1166 Gorham St # 3&4	Multi	Lease	6 TL	6.50/sf Net + 2.51 TMI	20' clear ceilings, 25% offices`
18,396	125 Harry Walker Pkwy	Freestand	Sale	2 TL, 2 DI	$1,564,000.	20' clear height, Very limited truck access – poor shipping – Availability is questionable
18,579	1180 Ringwell Dr	Freestand	Lease Sale	2 TL, 1 DI	6.50/sf Net $1,875,000.	18' Clear ht, 10% office
19,325	Lot 2 Maple Hill Crt	Freestand	Design/Build Lease Sale	2 TL, 2 DI	6.75/sf Net $2,310,000.	Proposed Precast construction, 20' clear Height, 10% mezzanine office, 6 – 8 month to build

20,000-50,000 Sq.Ft.

Size (Sq. Ft.)	Address	Freestand or Multi-Unit	Type	Loading Doors	Price	Comments
21,894	1311 Kerrisdale Blvd	Freestand	Lease	5 TL, 2 DI	6.50/sf Net + 2.50 TMI	22.5' Clear Height, 7% office space Owner may be willing to sell +$100/Sq ft
35,056	1175 Kerrisdale Blvd	Multi	SubLease	4 TL, 1 DI	4.75/sf Net + 2.96 TMI	18' Clear height, 8% office

Over 100,000 Sq. Ft.

Size (Sq. Ft.)	Address	Freestand or Multi-Unit	Type	Loading Doors	Price	Comments
100,000	1166 Nicholson Rd	Freestand	Design/Build Lease	10 TL, 2 DI	5.95/sf Net	Proposed Precast Construction, 24' Clear Height, Can be split into 10,000 sq ft multiples 8-10 months availability
105,110	210 Harry Walker Pkwy	Freestand	Lease	8 TL, 3 DI	5.50/sf Net + $2.00/SF Tax	Manufacturing Building, 27' clear ht 20% office

Exhibit 4: Operating Costs

Tab 7 (of 8): Depreciation and Amortization

DEPRECIATION EXPENSE METHODOLOGY, RATES AND EXPENSES

The Applicant amortizes its capital assets in accordance with the Canadian Institute of Chartered Accountants ("CICA") Handbook and the Board's Accounting Procedures Handbook for Electric Distribution Utilities ("APH"). All capital assets are amortized on a straight-line basis. Amortization expenses for 2008 and 2009 are the actual amounts incurred as compared to the 2010 expenses forecast for the test year.

As shown in the following table, the amortization expense increases on an annual basis as a result of the annual increases in capital assets. The Applicant has provided a normalized view of the annual amortization expense by removing the amortization associated with the government mandated jobs (as described in Exhibit 2).

Amortization expense			
	2008	**2009**	**2010**
Amortization	4,082,048	4,270,472	4,525,690
Less Gov't Mandated jobs	318,815	399,922	555,172
Normalized Amortization	3,763,233	3,870,550	3,970,518

The following table shows the detailed amortization by class of asset for 2010. Each asset class starts with the 2009 year end actual gross fixed asset value. This value is adjusted for any assets in the class that are fully amortized by that point in time. Pooled assets are tracked on an aggregate basis by the year in which they were placed in service. Individual assets are tracked separately based on the specific date they were placed in service.

When a group of pooled assets reaches the end of its amortization period, the Applicant removes the full cost of these assets and the associated accumulated amortization from the relevant asset accounts. Pooled assets continue to be repaired or refurbished near the end of their useful lives to avoid retiring functioning assets prematurely. When individual assets are removed from service the actual cost is calculated and recorded.

Both pooled and individual assets continue to be maintained and upgraded after they have been removed from the asset accounts until it is no longer cost effective to do so at which point they are physically removed from service in conjunction with the Applicant's replacement procedures.

Once the 2009 year end values are adjusted to remove any fully amortized assets, the 2010 year end value is calculated by adding the 2010 budget additions and deducting any assets that will become fully depreciated in 2010. Year-end 2009 and year-end 2010 values are then averaged to calculate the ½ year value. The average gross asset values are then divided by the annual straight line depreciation years as described above to determine the 2010 amortization values for each asset class. As can be seen by the chart above, the result of this calculation is higher (but in line with previous years) due to the size of the capital asset program over the past four years.

Asset Account		Asset Values	Avg Years for the Class	Depreciation Expense
1805	Dec-09	3,128,319		
Distribution - Land	Fully Depreciated to Dec 2009	0		
	Subtotal	3,128,319		
	Additions	0		
	Fully Depreciated in 2010	0		
	Dec-10	3,128,319		
	Average	3,128,319		0
1806	Dec-09	589,802		
Distribution - Land Rights	Fully Depreciated to Dec 2009	0		
	Subtotal	589,802		
	Additions	0		
	Fully Depreciated in 2010	0		
	Dec-10	589,802		
	Average	589,802	30	19,660
1820	Dec-09	8,879,447		
Mun Trans Stn<50kv	Fully Depreciated to Dec 2009	(563,340)		
	Subtotal	8,316,106		
	Additions	1,429,792		
	Fully Depreciated in 2010	(142,681)		
	Dec-10	9,603,218		
	Average	8,959,662	30	298,655
1830	Dec-09	14,924,554		
Distribution Lines o/h Poles	Fully Depreciated to Dec 2009	(1,364,350)		
	Subtotal	13,560,204		
	Additions	2,262,680		
	Fully Depreciated in 2010	(310,002)		
	Dec-10	15,512,882		
	Average	14,536,543	25	581,462
1835	Dec-09	17,085,100		
Distribution Lines o/h Cable	Fully Depreciated to Dec 2009	(1,364,350)		
	Subtotal	15,720,750		
	Additions	2,319,612		
	Fully Depreciated in 2010	(310,002)		
	Dec-10	17,730,360		
	Average	16,725,555	25	669,022
1840	Dec-09	8,431,458		
Distribution Lines u/g Conduit	Fully Depreciated to Dec 2009	(528,098)		
	Subtotal	7,903,360		
	Additions	537,894		
	Fully Depreciated in 2010	(89,048)		
	Dec-10	8,352,207		
	Average	8,127,784	25	325,111
1845	Dec-09	25,270,269		

Distribution Lines u/g Cable	Fully Depreciated to Dec 2009	(1,563,602)		
	Subtotal	23,706,667		
	Additions	1,679,077		
	Fully Depreciated in 2010	(356,190)		
	Dec-10	25,029,554		
	Average	24,368,111	25	974,724
1855	Dec-09	7,816,552		
Distribution Lines u/g Services	Fully Depreciated to Dec 2009	0		
	Subtotal	7,816,552		
	Additions	674,471		
	Fully Depreciated in 2010	0		
	Dec-10	8,491,023		
	Average	8,153,787	25	326,151
1850	Dec-09	17,258,394		
Distribution Transformers	Fully Depreciated to Dec 2009	(1,310,987)		
	Subtotal	15,947,407		
	Additions	1,489,888		
	Fully Depreciated in 2010	(340,832)		
	Dec-10	17,096,464		
	Average	16,521,935	25	660,877
1860	Dec-09	7,882,517		
Distribution Meters	Fully Depreciated to Dec 2009	(851,053)		
	Subtotal	7,031,464		
	Additions	49,364		
	Fully Depreciated in 2010	(120,788)		
	Dec-10	6,960,040		
	Average	6,995,752	25	279,830
1860	Dec-09	5,344,304		
Smart Meters	Fully Depreciated to Dec 2009	0		
	Subtotal	5,344,304		
	Additions	2,027,551		
	Fully Depreciated in 2010	0		
	Dec-10	7,371,855		
	Average	6,358,080	15	423,872
1910	Dec-09	710,826		
Leasehold Improvements	Fully Depreciated to Dec 2009	(332,676)		
	Subtotal	378,150		
	Additions	95,000		
	Fully Depreciated in 2010	(15,237)		
	Dec-10	457,914		
	Average	418,032	5	83,606
1915	Dec-09	370,990		
Office Equipment	Fully Depreciated to Dec 2009	(139,696)		
	Subtotal	231,294		
	Additions	12,040		

	Fully Depreciated in 2010	(13,046)		
	Dec-10	230,288		
	Average	230,791	10	23,079
1920	Dec-09	864,733		
Computer Equipment	Fully Depreciated to Dec 2009	(456,788)		
	Subtotal	407,945		
	Additions	45,100		
	Fully Depreciated in 2010	(46,170)		
	Dec-10	406,875		
	Average	407,410	5	81,482
1925	Dec-09	1,503,797		
Computer Software	Fully Depreciated to Dec 2009	(792,990)		
	Subtotal	710,807		
	Additions	260,200		
	Fully Depreciated in 2010	(284,369)		
	Dec-10	686,637		
	Average	698,722	5	139,744
1930	Dec-09	4,218,188		
Rolling Stock & Equip.	Fully Depreciated to Dec 2009	(1,793,765)		
	Subtotal	2,424,423		
	Additions	115,000		
	Fully Depreciated in 2010	(84,245)		
	Dec-10	2,455,178		
	Average	2,439,801	7.5	325,307
1935	Dec-09	151,247		
Stores Warehouse Equipment	Fully Depreciated to Dec 2009	(65,853)		
	Subtotal	85,394		
	Additions	0		
	Fully Depreciated in 2010	(5,062)		
	Dec-10	80,332		
	Average	82,863	10	8,286
1940	Dec-09	530,753		
Misc. Tools & Equip.	Fully Depreciated to Dec 2009	(314,285)		
	Subtotal	216,468		
	Additions	45,000		
	Fully Depreciated in 2010	(19,170)		
	Dec-10	242,299		
	Average	229,384	10	22,938
1945	Dec-09	102,535		
Measurement & Test Equipment	Fully Depreciated to Dec 2009	(2,493)		
	Subtotal	100,042		
	Additions	35,000		
	Fully Depreciated in 2010	(1,778)		
	Dec-10	133,263		

	Average	116,652	10	11,665
1980	Dec-09	742,641		
System Supervisory Equipment	Fully Depreciated to Dec 2009	(236,022)		
	Subtotal	506,619		
	Additions	0		
	Fully Depreciated in 2010	(77,349)		
	Dec-10	429,269		
	Average	467,944	15	31,196
1995	Dec-09	(17,859,155)		
Contributed Capital	Fully Depreciated to Dec 2009	0		
	Subtotal	(17,859,155)		
	Additions	(2,694,061)		
	Fully Depreciated in 2010	0		
	Dec-10	(20,553,217)		
	Average	(19,206,186)	25	(768,247)
1908	Dec-09	297,912		
Buildings	Fully Depreciated to Dec 2009	0		
	Subtotal	297,912		
	Additions	0		
	Fully Depreciated in 2010	0		
	Dec-10	297,912		
	Average	297,912	41	7,266
Summary	Dec-09	107,947,271		
	Fully Depreciated to Dec 2009	(11,680,349)		
	Subtotal	96,266,923		
	Additions	10,383,607		
	Fully Depreciated in 2010	(2,215,968)		
	Dec-10	104,434,561		
	Average	100,350,742		4,525,690

Capital assets are recorded either separately as identifiable items or as grouped or pooled assets. The grouped assets are managed as a pool of common items (as described above) for the purpose of amortization. Pooled amortization is applied to the assets groups shown in the following list.

Grouped Assets

Asset	Account	Grouped or Identifiable	Asset Life
Distribution Lines o/h Poles	1830	Grouped	25 Years
Distribution Lines o/h Cable	1835	Grouped	25 Years
Distribution Lines u/g Conduit	1840	Grouped	25 Years
Distribution Lines u/g Cable	1845	Grouped	25 Years
Services	1855	Grouped	25 Years
Distribution Transformers	1850	Grouped	25 Years
Distribution Meters	1860	Grouped	25 Years
Smart Meters	1860	Grouped	15 Years
Sentinel Lighting Units	1985	Grouped	15 Years
Contributed Capital	1995	Grouped	25 Years

Individual amortization is applied to the identifiable assets shown in the following list.

Identifiable Assets

Asset	Account	Grouped or Identifiable	Asset Life
Distribution - Land	1805	Identifiable	Not Depreciated
Distribution - Land Rights	1806	Identifiable	30 Years
Mun Trans Stn<50kv	1820	Identifiable	30 Years
Leasehold Improvements	1910	Identifiable	5 Years
Office Equipment	1915	Identifiable	10 Years
Computer Equipment	1920	Identifiable	5 Years
Computer Software	1925	Identifiable	5 Years
Stores Whse Equipment	1935	Identifiable	5 Years
Rolling Stock Large	1930	Identifiable	8 Years
Rolling Stock Small	1930	Identifiable	5 Years
Misc. Tools & Equip.	1940	Identifiable	10 Years
Measurement & Test Equipment	1945	Identifiable	10 Years
System Supervisory Equip	1980	Identifiable	15 Years

Exhibit 4: Operating Costs

Tab 8 (of 8): Income & Capital Taxes

OVERVIEW OF PROVISION IN LIEU OF TAXES (PILS)

This section of Exhibit 4 presents details on the Provision in Lieu of Taxes (PILS) and the table presented below summarized the Applicant' s calculations of its PILs.

Income Tax, Large Corporation Tax

	Summary of PILS T2S2		
	2008 Actual	2009 Actual	2010 Test
Accounting Income before taxes	$ 2,623,606	$ 2,755,162	$ 3,684,789
Regulatory Income			
Add Back			
Provision for income taxes-current	$ 1,608,000	$ 2,470,000	$ -
Accounting Amortization	$ 4,082,044	$ 4,249,838	$ 4,525,693
Non-Deduct portion of Meals & Entertainment	$ 15,000	$ 22,500	$ 30,000
Reserves End of Year	$ 1,138,882	$ 1,294,000	$ 1,337,000
Subtract Off			
CCA (see tax return)	$ (3,957,636)	$ (4,137,844)	$ (4,473,253)
CEC (see tax return)	$ (110,447)	$ (102,716)	$ (95,526)
Reserves beginning of year	$ (919,041)	$ (1,138,882)	$ (1,294,000)
Taxable Income	$ 4,480,408	$ 5,412,058	$ 3,714,703
Taxes			
Federal Proxy	$ 873,679	$ 1,028,291	$ 1,154,089
Provincial Proxy	$ 627,257	$ 862,641	
	$ 1,500,936	$ 1,890,932	$ 1,154,089
Taxable Capital for Ontario Capital Tax			
Taxable capital	$ 67,873,914	$ 69,459,129	$ 68,200,000
Reduction	$ 15,000,000	$ 15,000,000	$ 15,000,000
Rate	0.00225	0.00225	0.0015
2010 elimination on July 1			0.5
	$ 118,966	$ 122,533	$ 39,900

The Proposed PILs model presented at Exhibit 4, Tab 8, Schedule 3, Attachment 1 was developed by Elenchus Research Associates (“ERA”) and provide a detailed calculations of PILS for the 2009 Bridge Year and 2010 Test years.

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200
Code 0901

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, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax 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*.

055 Do not use this area

Identification

Business number (BN) **001** 86907 7925 RC 0001

Corporation's name
002 Newmarket - Tay Power Distribution Ltd

Address of head office
Has this address changed since the last time you filed your T2 return? **010** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 011 to 018)
011 590 Steven Court
012
City **015** Newmarket
Province, territory, or state **016** ON
Country (other than Canada) **017**
Postal code/Zip code **018** L3Y 6Z2

Mailing address (if different from head office address)
Has this address changed since the last time you filed your T2 return? **020** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 021 to 028)
021 c/o
022 590 Steven Court
023
City **025** Newmarket
Province, territory, or state **026** ON
Country (other than Canada) **027**
Postal code/Zip code **028** L3Y 6Z2

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? **030** 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 031 to 038)
031 590 Steven Court
032
City **035** Newmarket
Province, territory, or state **036** ON
Country (other than Canada) **037**
Postal code/Zip code **038** L3Y 6Z2

040 Type of corporation at the end of the tax year
1 ☒ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change **043**

To which tax year does this return apply?
Tax year start **060** 2009/01/01
Tax year-end **061** 2009/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? **063** 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired **065**

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? **070** 1 Yes ☐ 2 No ☒
Amalgamation? **071** 1 Yes ☐ 2 No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? **072** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada? **080** 1 Yes ☒ 2 No ☐
If **no**, give the country of residence on line 081 and complete and attach Schedule 97. **081**

Is the non-resident corporation claiming an exemption under an income tax treaty? **082** 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085 1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules - Answer the following questions. For each **yes** response, **attach** to the T2 return the schedule that applies.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **Yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		-----
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	-----
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	-----
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax?	255		92 *

*** We do not print this schedule.**

Attachments - Continued from page 2

	Line	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

	Line	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	Electrcity Distribution	285	100.000 %
286		287	%
288		289	%

	Line	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**

If the corporation's major business activity is construction, did you have any sub-contractors 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		5,412,058	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		▶		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			5,412,058	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		5,412,058	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	5,412,058	A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632* on page 7, **minus** 3 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	5,412,058	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 / Number of days in the tax year	365 / 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 *** 11,250 D / 11,250) = 500,000 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425	0	F

Small business deduction

Amount A, B, C, or F whichever is the least		X	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 365	x 16% =	5
Amount A, B, C, or F whichever is the least		X	Number of days in the tax year after December 31, 2007 / Number of days in the tax year	365 / 365	x 17% =	6

Total of amounts 5 and 6 - enter on line 9 of page 7	430	0	G

* Calculate the amount of foreign non-business income tax credit deductible at line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3			5,412,058	A
Lesser of amounts V and Y 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 on page 4, whichever is the least		E		
Aggregate investment income from line 440 of page 6		F		
Total of amounts B to F		▸		G
Amount A **minus** amount G (if negative, enter "0")			5,412,058	H

Amount H	5,412,058	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 365	x 7% =	I
Amount H	5,412,058	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% =	J
Amount H	5,412,058	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 / 365	x 9% = 487,085	K
Amount H	5,412,058	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	x 10% =	L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L 487,085 M

Enter amount M on line 638 of page 7.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, 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 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 before January 1, 2008 / Number of days in the tax year		x 7% =	T
Amount S		x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year		x 8.5% =	U
Amount S		x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year		x 9% =	V
Amount S		x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year		x 10% =	W

General tax reduction – Total of amounts T to W X

Enter amount X on line 639 of page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440	X 26 2/3 % =		A
Foreign non-business income tax credit from line 632 on page 7				
Deduct:				
Foreign investment income from Schedule 7	445	X 9 1/3 % =		
		(if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")				C
Taxable income from line 360 on page 3		5,412,058		
Deduct:				
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least				
Foreign non-business income tax credit from line 632 of page 7	x 25/9 =			
Foreign business income tax credit from line 636 of page 7	x 3 =			
		5,412,058 X 26 2/3% =	1,443,215	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)		1,028,291		
Deduct: Corporate surtax from line 600 of page 7				
Net amount		1,028,291	1,028,291	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450		0	F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			
				G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
				H
Refundable dividend tax on hand at the end of the tax year - Amount G **plus** amount H	485		0	

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3		X 1/3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 of page 8)			0	

Part I tax

Base amount of Part I tax

taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38%			550	2,056,582 A

Corporate surtax calculation

Base amount from line A above		2,056,582	1
Deduct:			
10% of taxable income (line 360 or amount Z, whichever applies) from page 3		541,206	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28% of taxable income from line 360 on page 3	a		
28% of taxed capital gains	b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	1,028,291 c		
Total of lines 2 to 6		541,206	7
Net amount (line 1 **minus** line 7)		1,515,376	8

Corporate surtax*

Line 8 1,515,376 x (Number of days in the tax year before January 1, 2008 ______ / Number of days in the tax year 365) x 4% = **600** ______ B

*The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 **602** ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	5,412,058		
Deduct: Amount on line 400, 405, 410, or 425 of page 4, whichever is the least			
Net amount	5,412,058 ▶	5,412,058	ii

Refundable tax on CCPC's investment income – 6 2/3% of whichever is less: amount i or ii **604** ______ D

Subtotal (**add** lines A to D) 2,056,582 E

Deduct:

Small business deduction from line 430 on page 4			9
Federal tax abatement	608	541,206	
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 on page 5	638	487,085	
General tax reduction from amount X on page 5	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		1,028,291 ▶	1,028,291 F

Part I tax payable – Line E **minus** line F 1,028,291 G

Enter amount G on line 700 of page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	1,028,291
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		1,028,291

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	862,641	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		862,641 ▸	862,641
Total tax payable	770		1,890,932 A

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund Code 894 Overpayment

Balance (line A **minus** line B) 1,890,932 I

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 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 1,890,932

Enclosed payment 898

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒ NA ☐

Certification

I, 950 Clinton (Last name) 951 Iain (First name) 954 Chief Financial Officer (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 tax year except as specifically disclosed in a statement attached to this return.

955 2010/05/25 (Date) ______ Signature of the authorized signing officer of the corporation 956 (905) 953-8548 (Telephone number)

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. 957 1 Yes ☐ 2 No ☒

958 Iain Clinton, CA (Name) 959 (905) 953 - 8548 (Telephone number)

Language of correspondence - Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French. 990 1
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

Canada Revenue Agency | Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1
Code 0901

- 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			A	2,755,162
Add:				
Provision for income taxes - current	101	2,470,000		
Amortization of tangible assets	104	4,249,838		
Non-deductible meals and entertainment expenses 45,000 X 50%	121	22,500		
Reserves from financial statements - balance at the end of the year	126	1,294,000		
Total of lines 101 to 199	500	8,036,338	▶	8,036,338
Deduct:				
Capital cost allowance from Schedule 8	403	4,137,844		
Cumulative eligible capital deduction from Schedule 10	405	102,716		
Reserves from financial statements - balance at the beginning of the year	414	1,138,882		
Total of lines 401 to 499	510	5,379,442	▶	5,379,442
Net income (loss) for income tax purposes - enter on line 300 on page 3 of the T2 return				5,412,058

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Schedule 5
Code 0902

TAX CALCULATION SUPPLEMENTARY - CORPORATIONS

Part 1 - Allocation of taxable income

100 402 Enter the Regulation that applies (402 to 413).

A		B	C	D	E	F
Jurisdiction Tick **Yes** if the corporation had a permanent establishment in the jurisdiction during the tax year. *		Total salaries and wages paid in jurisdiction	(B x taxable income**) ÷ G	Gross revenue attributable to jurisdiction	(D x taxable income**) ÷ H	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 ☐	113		153		5,412,058
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		5,412,058

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking center; 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 computing the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see line 760 of the *T2 Corporation - Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2 on the following pages.

Part 2 - Provincial and territorial tax payable, tax credits, and rebates

Newfoundland and Labrador

Newfoundland and Labrador tax before credits		200		
Add: Newfoundland and Labrador offshore tax		205		
Gross Newfoundland and Labrador tax			▶	A1
Deduct:				
Newfoundland and Labrador political contribution tax credit		500		
Contribution	891			
Newfoundland and Labrador foreign tax credit (from Schedule 21)		501		
Newfoundland and Labrador manufacturing and processing profits tax credit (from Schedule 300)		503		
Newfoundland and Labrador direct equity tax credit (from Schedule 303)		505		
Newfoundland and Labrador resort property investment tax credit (from Schedule 304)		507		
Newfoundland and Labrador small business tax holiday *		511		
Small business tax holiday certificate number (from Form NLSBTH)	832			
Subtotal			▶	B1
Subtotal (amount A1 **minus** amount B1) (if negative, enter "0")				C1
Add::				
Newfoundland and Labrador capital tax on financial institutions (from Schedule 305)		518		
Total Newfoundland and Labrador tax payable before refundable credits (amount C1 **plus** amount on line 518) (if negative, enter "0")				D1
Deduct:				
Newfoundland and Labrador research and development tax credit (from Schedule 301)		520		
Newfoundland and Labrador film and video industry tax credit		521		
Certificate number	821			
Subtotal			▶	E1
Net Newfoundland and Labrador tax payable or refundable credit (amount D1 **minus** amount E1)			209	F1

(if a credit, enter amount in brackets) Include this amount on line 255.

* The amount of Newfoundland and Labrador small business tax holiday cannot be more than the gross Newfoundland and Labrador tax **minus** all other Newfoundland and Labrador tax credits (including the refundable credits).

Prince Edward Island

Prince Edward Island tax before credits			210	A2
Deduct:				
Prince Edward Island political contribution tax credit		525		
Contribution	892			
Prince Edward Island foreign tax credit (from Schedule 21)		528		
Prince Edward Island corporate investment tax credit (from Schedule 321)		530		
Subtotal			▶	B2
Net Prince Edward Island tax payable (amount A2 **minus** amount B2) (if negative, enter "0")			214	C2

Include this amount on line 255.

Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Nova Scotia

Nova Scotia tax before credits (from Schedule 346)		215		
Add:				
Nova Scotia offshore tax (from Schedule 346)		220		
Recapture of Nova Scotia research and development tax credit (from Schedule 340)		221		
Gross Nova Scotia tax				A3
Deduct:				
Nova Scotia political contribution tax credit		550		
Contribution	893			
Nova Scotia foreign tax credit (from Schedule 21)		554		
Nova Scotia manufacturing and processing investment tax credit (from Schedule 344)		561		
Nova Scotia corporate tax reduction for new small businesses * (from Schedule 341)		556		
Certificate number	834			
Manufacturing and processing investment tax credit (10%)				
Subtotal				B3
Total Nova Scotia tax payable before refundable credits (amount A3 **minus** amount B3) (if negative, enter "0")				C3
Deduct:				
Nova Scotia film industry tax credit		565		
Certificate number	836			
Nova Scotia research and development tax credit (from Schedule 340)		566		
Nova Scotia digital media tax credit		567		
Certificate number	838			
Subtotal				D3
Net Nova Scotia tax payable or refundable credit (amount C3 **minus** amount D3) (if a credit, enter amount in brackets) Include this amount on line 255.			224	E3

* The amount of Nova Scotia corporate tax reduction for new small businesses cannot be more than the gross Nova Scotia tax **minus** all other Nova Scotia tax credits (including the refundable credits).

New Brunswick

New Brunswick tax before credits (from Schedule 366)		225		
Add:				
Recapture of New Brunswick research and development tax credit (from Schedule 360)		573		
Gross New Brunswick tax				A4
Deduct:				
New Brunswick political contribution tax credit		575		
Contribution	894			
New Brunswick foreign tax credit (from Schedule 21)		576		
New Brunswick non-refundable research and development tax credit (from Schedule 360)		577		
Subtotal				B4
Total New Brunswick tax payable before refundable credits (amount A4 **minus** amount B4) (if negative, enter "0")				C4
Deduct:				
New Brunswick film tax credit		595		
Certificate number	850			
New Brunswick refundable research and development tax credit (from Schedule 360)		597		
Subtotal				D4
Net New Brunswick tax payable or refundable credit (amount C4 **minus** amount D4) (if a credit, enter amount in brackets) Include this amount on line 255.			229	E4

Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Ontario
(2009 and later tax years only)

Ontario basic income tax (from Schedule 500)	270	757,688		
Deduct: Ontario small business deduction (from Schedule 500)	402	42,500		
Subtotal (if negative, enter "0")		715,188	715,188	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272	42,500		
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		42,500	42,500	B6
Subtotal (amount A6 **plus** amount B6)			757,688	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 contribution tax credit (from Schedule 525)	415			
Subtotal				D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			757,688	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")			757,688	F6
Deduct: Ontario corporate minimum tax credit (from Schedule 510)	418			
Ontario corporate income tax payable (amount F6 minus amount on line 418) (if negative, enter "0")			757,688	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	104,953		
Subtotal		104,953	104,953	H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			862,641	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			
Subtotal				J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6)		290	862,641	K6

(if a credit, enter amount in brackets) Include this amount on line 255.

Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Manitoba

Manitoba tax before credits (from Schedule 383)			230	A7
Deduct:				
Manitoba foreign tax credit (from Schedule 21)	601			
Manitoba manufacturing investment tax credit (from Schedule 381)	605			
Manitoba research and development tax credit (from Schedule 380)	606			
Manitoba co-op education and apprenticeship tax credit (from Schedule 384)	603			
Manitoba odour-control tax credit (from Schedule 385)	607			
Manitoba community enterprise investment tax credit (from Schedule 387)	608			
Subtotal				B7
Total Manitoba tax payable before refundable credits (amount A7 **minus** amount B7) (if negative, enter "0")				C7
Deduct:				
Manitoba interactive digital media tax credit	614			
Manitoba book publishing tax credit (from Schedule 389)	615			
Manitoba green energy equipment tax credit (manufacturer)	618			
Manitoba green energy equipment tax credit (purchaser)	619			
Manitoba film and video production tax credit *	620			
Certificate number 856				
Manitoba refundable manufacturing investment tax credit (from Schedule 381)	621			
Manitoba refundable co-op education and apprenticeship tax credit (from Schedule 384)	622			
Manitoba refundable odour-control tax credit for agricultural corporations (from Schedule 385)	623			
Manitoba refundable research and development tax credit (from Schedule 380)	613			
Subtotal				D7
Net Manitoba tax payable or refundable credit (amount C7 **minus** amount D7) (if a credit, enter amount in brackets) Include this amount on line 255.			234	E7

* If you received a certificate from the Manitoba Department of Finance it should be claimed on line 620. If you have more than one certificate, use Schedule 382. If the certificate was issued by Manitoba Film and Sound Recording Development Corporation, complete Schedule 388, *Manitoba Film and Video Production Tax Credit*, to calculate the amount of the credit and enter your claim on line 620.

Saskatchewan

Saskatchewan tax before credits (from Schedule 411)			235	A8
Deduct:				
Saskatchewan political contribution tax credit	624			
Contribution 890				
Saskatchewan foreign tax credit (from Schedule 21)	625			
Saskatchewan manufacturing and processing profits tax reduction (from Schedule 404)	626			
Saskatchewan manufacturing and processing investment tax credit (from Schedule 402)	630			
Saskatchewan research and development tax credit (from Schedule 403)	631			
Saskatchewan royalty tax rebate (from Schedule 400)	632			
Subtotal				B8
Total Saskatchewan tax payable before refundable credits (amount A8 **minus** amount B8) (if negative, enter "0")				C8
Deduct:				
Saskatchewan qualifying environmental trust tax credit	641			
Saskatchewan film employment tax credit	643			
Certificate number 860				
Saskatchewan refundable manufacturing and processing investment tax credit (from Schedule 402)	644			
Saskatchewan refundable research and development tax credit (from Schedule 403)	645			
Subtotal				D8
Net Saskatchewan tax payable or refundable credit (amount C8 **minus** amount D8) (if a credit, enter amount in brackets) Include this amount on line 255.			239	E8

Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

British Columbia

British Columbia tax before credits (from Schedule 427) 240

Add:

Recapture of British Columbia scientific research and experimental development (SR&ED) tax credit (from Form T666) 241

Gross British Columbia tax A10

Deduct:

British Columbia foreign tax credit (from Schedule 21)		650	
British Columbia logging tax credit		651	
British Columbia political contribution tax credit		653	
Contribution	896		
British Columbia small business venture capital tax credit		656	
Credit at the end of previous tax year	880		
Current-year credit	881		
Certificate number (from SBVC 10)	882		
British Columbia manufacturing and processing tax credit (from Schedule 426)		660	
British Columbia SR&ED non-refundable tax credit (from Form T666)		659	
Subtotal			B10

Total British Columbia tax payable before refundable credits (amount A10 **minus** amount B10) (if negative, enter "0") C10

Deduct:

British Columbia qualifying environmental trust tax credit		670	
British Columbia film and television tax credit (from Form T1196)		671	
British Columbia production services tax credit (from Form T1197)		672	
British Columbia mining exploration tax credit (from Schedule 421)		673	
British Columbia SR&ED refundable tax credit (from Form T666)		674	
British Columbia book publishing tax credit (amount on line 886 multiplied by 90%)		665	
Book Publishing Industry Development Program contribution received in the tax year	886		
British Columbia training tax credit (from Schedule 428)		679	
Subtotal			D10

Net British Columbia tax payable or refundable credit (amount C10 **minus** amount D10) 244 E10

(if a credit, enter amount in brackets) Include this amount on line 255.

Yukon

Yukon tax before credits 245 A11

Deduct:

Yukon political contribution tax credit		675	
Contribution	897		
Yukon foreign tax credit (from Schedule 21)		676	
Yukon manufacturing and processing profits tax credit (from Schedule 440)		677	
Subtotal			B11

Total Yukon tax payable before refundable credits (amount A11 **minus** amount B11) (if negative, enter "0") C11

Deduct:

Yukon mineral exploration tax credit (from Schedule 441)		697	
Yukon research and development tax credit (from Schedule 442)		698	
Subtotal			D11

Net Yukon tax payable or refundable credit (amount C11 **minus** amount D11) 249 E11

(if a credit, enter amount in brackets) Include this amount on line 255.

Part 2 - Provincial and territorial tax payable, tax credits, and rebates (continued)

Northwest Territories

Northwest Territories tax before credits			250	A12
Deduct:				
Northwest Territories political contribution tax credit		700		
Contribution	898			
Northwest Territories foreign tax credit (from Schedule 21)		701		
Northwest Territories investment tax credit (from Schedule 460)		705		
Subtotal				B12
Net Northwest Territories tax payable (amount A12 **minus** amount B12) (if negative, enter "0")			254	C12

Include this amount on line 255.

Nunavut

Nunavut tax before credits			260	A13
Deduct:				
Nunavut political contribution tax credit		725		
Contribution	899			
Nunavut foreign tax credit (from Schedule 21)		730		
Northwest Territories investment tax credit on investments made before April 1, 1999 (from Schedule 460)		734		
Nunavut investment tax credit (from Schedule 480)		735		
Subtotal				B13
Total Nunavut tax payable before refundable credits (amount A13 **minus** amount B13) (if negative, enter "0")				C13
Deduct:				
Nunavut business training tax credit (from Schedule 490)			740	D13
Net Nunavut tax payable (amount C13 **minus** amount D13)			264	E13

(if a credit, enter amount in brackets) Include this amount on line 255.

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	255	862,641

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 on page 8 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 on page 8 of the T2 return.

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CAPITAL COST ALLOWANCE

Schedule 8

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

1 Class 200	2 UCC at start of year 201	3 Cost of additions in the year 203	4 Net adjustments 205	5 Proceeds of dispositions in the year 207	7 Adjustment for additions (1/2 x (col 3 - 5)) 211	8 Base amount for CCA	9 Rate % 212	10 Recapture of CCA 213	11 Terminal loss 215	12 CCA for the year (col 8 x 9 or a lower amount) 217	13 UCC at the end of the year 220
1	34,610,525	222,377			111,189	34,721,713	4			1,388,869	33,444,033
3	6,436					6,436	5			322	6,114
8	2,115,873	44,293			22,147	2,138,019	20			427,604	1,732,562
10	1,585,367	346,763			173,382	1,758,748	30			527,624	1,404,506
17	50,912					50,912	8			4,073	46,839
2	6,406,748					6,406,748	6			384,405	6,022,343
47	13,060,052	4,969,564			2,484,782	15,544,834	8			1,243,587	16,786,029
45	10,705					10,705	45			4,817	5,888
12	33,467	38,316			19,158	52,625	100			52,625	19,158
50	83,746	26,096			13,048	96,794	55			53,237	56,605
13	188,120	254,135			127,068	315,187	NA			50,681	391,574
							NA				
Totals	58,151,951	5,901,544			2,950,774	61,102,721				4,137,844	59,915,651

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RELATED AND ASSOCIATED CORPORATIONS

Schedule 9

This form is to be completed by a corporation having one or more of the following:

- related corporation(s)
- associated corporation(s)

Name 100	Country (if not Canada) 200	Business # (Canadian corporation only) 300	Code note 1 400	Common shares # owned 500	Common shares % owned 550	Preferred shares # owned 600	Preferred shares % owned 650	Book value of capital stock 700
Newmarket Hydro Holdings Inc		86514 2632 RC 0001	1	930	93.000			3,870,000
Unipower Holdings Ltd		86553 9399 RC 0001	3					
1443393 Ontario Inc		89239 7613 RC 0001	3					
1443394 Ontario Inc		86553 9191 RC 0001	3					
1443396 Ontario Inc		86553 8995 RC 0001	3					
1443397 Ontario Inc		89239 7217 RC 0001	3					
1443398 Ontario Inc		86553 8797 RC 0001	3					
1402318 Ontario Inc		86709 9772 RC 0001	3					
Tay Utility Contracting Inc		86777 9449 RC 0001	3					
Tay Hydro Inc		86863 4528 RC 0001	1	70	7.000			
Township of Tay		NR	3					

Note 1 : Enter the code number of the relationship that applies: 1- Parent 2 - Subsidiary 3 - Associated 4 - Related, but not associated

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CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Schedule 10

Part 1 - Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	1,467,372	A
Add: Cost of eligible capital property acquired during the taxation year	222					
Other adjustments	226					
Subtotal (line 222 plus line 226)			x 3/4 =			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1/2 =			C
amount B minus amount C (if negative, enter "0")				▸		D
Amount transferred on amalgamation or wind-up of subsidiary				224		E
Subtotal (add amounts A, D, and E)				230	1,467,372	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H			
Other adjustments	246		I			
(add amounts G, H, and I)			x 3/4 =	248		J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)					1,467,372	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249			
amount K	1,467,372					
less amount from line 249						
Current year deduction	1,467,372	x 7% =	250	102,716 *		
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				102,716 ▸	102,716	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	1,364,656	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80 (7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4			
Line 3 minus line 4 (if negative, enter "0")			▸		5	
Total of lines 1, 2, and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	409		▸		9	
Line 6 minus line 9 (if negative, enter "0")						O
Line N minus line O (if negative, enter "0")						P
Line 5			x 1/2 =			Q
Line P minus line Q (if negative, enter "0")						R
Amount R			x	66.6667		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410		

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Schedule 23
Code 0901

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (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**

Enter the calendar year to which the agreement applies **050** 2009

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? **075** ☐ 1 Yes ☒ 2 No

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300
1	Newmarket - Tay Power Distribution Ltd	86907 7925 RC 0001	1
2	Newmarket Hydro Holdings Inc	86514 2632 RC 0001	1
3	Unipower Holdings Ltd	86553 9399 RC 0001	1
4	1443393 Ontario Inc	89239 7613 RC 0001	1
5	1443394 Ontario Inc	86553 9191 RC 0001	1
6	1443396 Ontario Inc	86553 8995 RC 0001	1
7	1443397 Ontario Inc	89239 7217 RC 0001	1
8	1443398 Ontario Inc	86553 8797 RC 0001	1
9	1402318 Ontario Inc	86709 9772 RC 0001	1
10	Tay Utility Contracting Inc	86777 9449 RC 0001	
11	Tay Hydro Inc	86863 4528 RC 0001	
12	Township of Tay	NR	

Allocate business limit using: ☒ % ☐ $

	Taxation year Start	Taxation year End	4 Business limit for the year (before the allocation) $	Allocating business limit: 5 Percentage of the business limit (%) 350	6 Business limit allocated * $ 400	7 Gross Part I.3 tax for business limit reduction
1	2009/01/01	2009/12/31	500,000	100.000	500,000	46,509
2	2010/01/01	2010/12/31	500,000			
3	2010/01/01	2010/12/31	500,000			
4	2010/01/01	2010/12/31	500,000			
5	2010/01/01	2010/12/31	500,000			
6	2010/01/01	2010/12/31	500,000			
7	2010/01/01	2010/12/31	500,000			
8	2010/01/01	2010/12/31	500,000			
9	2010/01/01	2010/12/31	500,000			
10						
11						
12						
TOTALS				100.000	A 500,000	46,509

If the taxation year of the corporation filing this form is less than 51 weeks, enter the prorated business limit in this box. $ 500,000

AGREEMENT AMONG ASSOCIATED CCPCs TO ALLOCATE THE BUSINESS LIMIT

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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PART I.3 TAX ON LARGE CORPORATIONS

Schedule 33

- File this schedule if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Even if there is no Part I.3 tax payable for the days in the tax year that are after 2005, you must still complete this schedule (except parts 5 and 9).
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution", "long-term debt" and "reserves".
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- No Part I.3 tax is payable for a taxation year by a corporation that was:
  1) bankrupt [as defined by subsection 128(3)] at the end of the year;
  2) a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
  3) exempt from tax under section 149 throughout the year on all of its taxable income;
  4) neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
  5) a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
- File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of printing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

Add the following amounts at the end of the year:

Reserves that have not been deducted in computing income for the year under Part I	101	1,294,000			
Capital stock (or members' contributions if incorporated without share capital)	103	27,140,206			
Retained earnings	104	6,285,551			
Contributed surplus	105				
Any other surpluses	106				
Deferred unrealized foreign exchange gains	107				
All loans and advances to the corporation	108	29,822,000			
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		64,541,757	▸	64,541,757	A

Deduct the following amounts:

Deferred tax debit balance at the end of the year	121				
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			▸		B
Capital for the year (amount A minus amount B) (if negative, enter "0")			190	64,541,757	

Part 2 - Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	2,896,000
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership	407	
Investment allowance for the year (add lines 401 to 407)	490	2,896,000

PART I.3 TAX ON LARGE CORPORATIONS

Part 3 - Taxable capital

Capital for the year (line 190)		64,541,757	C
Deduct: Investment allowance for the year (line 490)		2,896,000	D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500	61,645,757	

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) 61,645,757 x (Taxable income earned in Canada **610** 5,412,058 / Taxable income 5,412,058) = **690** 61,645,757 **Taxable capital employed in Canada**

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada			701	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711			
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada	713			
Total deductions (add lines 711, 712, and 713)				E
Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0")			790	

PART I.3 TAX ON LARGE CORPORATIONS

Part 5 - Calculation of gross Part I.3 tax

If the tax year starts after 2005, do not complete this part.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		61,645,757
Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36)		50,000,000
Excess of taxable capital employed in Canada over capital deduction	811	

Line 811 ________ x (Number of days in the tax year in 2004 / Number of days in the tax year) ________ / 365 x 0.002 = ________ F

Line 811 ________ x (Number of days in the tax year in 2005 / Number of days in the tax year) ________ / 365 x 0.00175 = ________ G

Note: The Part I.3 tax rate is reduced to 0% for the days in the tax year that are after 2005.

Subtotal (add amounts F and G) ________ H

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax as follows:

Amount H ________ X Number of days in the year (________) / 365 = ________ I

Gross Part I.3 tax (amount H or I, whichever applies) 820 ________

Part 6 – Calculation of gross Part I.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies)		61,645,757	J
Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36)	801 50,000,000 x 1/5 =	10,000,000	K
Excess (amount J minus amount K) (if negative, enter "0")		51,645,757	L
Amount L 51,645,757 x 0.00225 =		116,203	M

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax for purposes of the unused surtax credit as follows:

Amount M ________ x Number of days in the year (________) / 365 = ________ N

Gross Part I.3 tax for purposes of the unused surtax credit (amount M or N, whichever applies) 821 116,203

PART I.3 TAX ON LARGE CORPORATIONS

Part 7 - Calculation of current-year surtax credit available

- Corporations can claim a credit against their Part I.3 tax for the amount of Canadian surtax payable for the year. This is called the surtax credit.
- Any unused surtax credit can be carried back three years or carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subsection 181.1(7) when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.

For a corporation that was a non-resident of Canada throughout the year, enter amount **a** or **b** at line O, whichever is less:

a) line 600 from the T2 return		**a**		
b) line 700 from the T2 return		**b**		O

In any other case, enter amount **c** or **d** at line P, whichever is less:

c) line 600 from the T2 return ______ x (line 690 ÷ line 500) =		**c**		
d) line 700 from the T2 return	1,028,291	**d**		P
Current-year surtax credit available (amount O or P, whichever applies)		**830**		

Part 8 - Calculation of current-year unused surtax credit

Current-year surtax credit available (line 830)		
Less: Gross Part I.3 tax for purposes of the unused surtax credit (line 821)		116,203
Current-year unused surtax credit (if negative, enter "0")	**850**	

Enter this amount at line 600 on Schedule 37.

Part 9 - Calculation of net Part I.3 tax payable

If the tax year starts after 2005, do not complete this part.

Gross Part I.3 tax (line 820)				Q
Deduct:				
Current-year surtax credit applied (line 820 or 830, whichever is less)	**861**			
Unused surtax credit from previous years applied (amount from line 320 on Schedule 37)	**862**			
Subtotal (cannot be more than amount on line 820)				R
Net Part I.3 tax payable (amount Q minus amount R)		**870**		

Enter this amount at line 704 of the T2 return.

Part 10 - Calculation for purposes of the small business deduction

This part is applicable only to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)	61,645,757	S
Deduct:		
Capital deduction claimed for the year (enter $10,000,000)	10,000,000	T
Excess (amount S minus amount T) (if negative, enter "0")	51,645,757	U
Gross Part I.3 tax for purposes of the small business deduction (Amount U x 0.00225)	116,203	V

Enter this amount at line 415 of the T2 return.

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Schedule 36

AGREEMENT AMONG RELATED CORPORATIONS - PART I.3 TAX

- Corporations related at any time in their tax year that ends in the calendar year of the agreement should use this schedule to allocate the capital deduction of $50,000,000 among the members of the related group if:
  - any member applies the surtax credit against Part I.3 tax in a tax year starting before January 1, 2006; or
  - any member wants to carry back an unused surtax credit against Part I.3 tax to a tax year starting before January 1, 2006.
- According to subsection 181.5(7) of the *Income Tax Act*, a Canadian-controlled private corporation is not considered to be related to another corporation for the capital deduction unless it is also associated with that corporation.
- In cases where a related corporation has more than one tax year ending in a calendar year, it has to file this agreement for each of those tax years.
- According to subsection 181.5(5), where a corporation has more than one tax year ending in the same calendar year and is related in two or more of those tax years to another corporation that has a tax year ending in that calendar year, the capital deduction of the first corporation for each such tax year at the end of which it is related to the other corporation is an amount equal to its capital deduction for the first such tax year.
- Any corporation in the related group may file this agreement on behalf of the group. However, if an agreement is not already on file with us when we assess any of the returns for a tax year ending in the calendar year of the agreement, we will ask for one.

Agreement

Date filed (do not use this area) **010**

Is this an amended agreement? **020** ☐ 1 Yes ☒ 2 No

Calendar year to which the agreement applies **030** 2009

Note: This agreement must include all the information indicated below for all members of the related group, including members to which no amount of capital deduction is allocated for the year. However, any member that is exempt from Part I.3 tax under subsection 181.1(3) of the *Income Tax Act* does not have to be included.

Name of each corporation that is a member of the related group **200**	Business number (if a corporation is not registered, enter "NR") **300**	Allocation of capital deduction for the year $ **400**
Newmarket - Tay Power Distribution Ltd	86907 7925 RC 0001	50,000,000
Newmarket Hydro Holdings Inc	86514 2632 RC 0001	0
Unipower Holdings Ltd	86553 9399 RC 0001	0
1443393 Ontario Inc	89239 7613 RC 0001	0
1443394 Ontario Inc	86553 9191 RC 0001	0
1443396 Ontario Inc	86553 8995 RC 0001	0
1443397 Ontario Inc	89239 7217 RC 0001	0
1443398 Ontario Inc	86553 8797 RC 0001	0
1402318 Ontario Inc	86709 9772 RC 0001	0
Tay Utility Contracting Inc	86777 9449 RC 0001	0
Tay Hydro Inc	86863 4528 RC 0001	0
Township of Tay	NR	0
	Total (cannot be more than $50,000,000)	50,000,000

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SHAREHOLDER INFORMATION

Schedule 50

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual or trust) 100	Business Number (If a corporation is not registered, enter "NR") * 200	Social Insurance Number * 300	Trust Number (If a trust number is not available, enter "NA") * 350	Percentage common shares 400	Percentage preferred shares 500
Newmarket Hydro Holdings Inc	86514 2632 RC 0001			93.000	
	RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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SCHEDULE 53
Code 0901

GENERAL RATE INCOME POOL (GRIP) CALCULATION

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act.*
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year						100	5,317,124	A
Taxable income for the year (DICs enter "0")*			110	5,412,058	B			
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120	0						
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130	0						
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140	0						
Subtotal (**add** lines 120, 130 and 140)		0 ▸		0	C			
Income taxable at the general corporate rate (line B **minus** line C)			150	5,412,058				
After-tax income (line 150 x general rate factor for the tax year ** 0.6800)						190	3,680,199	D
Eligible dividends received in the tax year			200	0				
Dividends deductible under section 113 received in the tax year			210	0				
Subtotal (**add** lines 200 and 210)				0 ▸			0	E
GRIP addition:								
Becoming a CCPC (line PP from Part 4)			220	0				
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)			230	0				
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)			240	0				
Subtotal (**add** lines 220, 230, and 240)				0 ▸		290	0	F
Subtotal (**add** lines A, D, E, and F)							8,997,323	G
Eligible dividends paid in the previous tax year			300	0				
Excessive eligible dividend designations made in the previous tax year			310	0				
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.								
Subtotal (line 300 **minus** line 310)				0 ▸			0	H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)						490	8,997,323	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)						560	0	
GRIP at the end of the tax year (line 490 minus line 560)						590	8,997,323	

Enter this amount on line 160 on Schedule 55.

* For lines 110, 120, 130 and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is the total of 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 on page 5 for tax years that straddle these dates.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1.

First previous tax year

Taxable income before specified future tax consequences from the current tax year		0 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)	0 K1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L1			
Aggregate investment income (line 440 of the T2 return)	0 M1			
Subtotal (**add** lines K1, L1, and M1)	0 ▶	0 N1		
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		0 ▶	0 O1	
Taxable income after specified future tax consequences		0 P1		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R1			
Aggregate investment income (line 440 of the T2 return)	0 S1			
Subtotal (**add** lines Q1, R1, and S1)	0 ▶	0 T1		
Subtotal (line P1 **minus** line T1) (if negative, enter "0")		0 ▶	0 U1	
Subtotal (line O1 **minus** line U1) (if negative, enter "0")			0 V1	
GRIP adjustment for specified future tax consequences to first previous tax year (line V1 **multiplied by** the general rate factor for the tax year 0.6800)				**500** 0

Second previous tax year

Taxable income before specified future tax consequences from the current tax year		0 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)	0 K2			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L2			
Aggregate investment income (line 440 of the T2 return)	0 M2			
Subtotal (**add** lines K2, L2, and M2)	0 ▶	0 N2		
Subtotal (line J2 **minus** line N2) (if negative, enter "0")		0 ▶	0 O2	
Taxable income after specified future tax consequences		0 P2		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q2			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R2			
Aggregate investment income (line 440 of the T2 return)	0 S2			
Subtotal (**add** lines Q2, R2, and S2)	0 ▶	0 T2		
Subtotal (line P2 **minus** line T2) (if negative, enter "0")		0 ▶	0 U2	
Subtotal (line O2 **minus** line U2) (if negative, enter "0")			0 V2	
GRIP adjustment for specified future tax consequences to second previous tax year (line V2 **multiplied by** the general rate factor for the tax year 0.6800)				**520** 0

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year

Taxable income before specified future tax consequences from the current tax year		0 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)	0 K3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L3			
Aggregate investment income (line 440 of the T2 return)	0 M3			
Subtotal (**add** lines K3, L3, and M3)	0 ▶	0 N3		
Subtotal (line J3 **minus** line N3) (if negative, enter "0")		0 ▶	0 O3	
Taxable income after specified future tax consequences		0 P3		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 Q3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 R3			
Aggregate investment income (line 440 of the T2 return)	0 S3			
Subtotal (**add** lines Q3, R3, and S3)	0 ▶	0 T3		
Subtotal (line P3 **minus** line T3) (if negative, enter "0")		0 ▶	0 U3	
Subtotal (line O3 **minus** line U3) (if negative, enter "0")			0 V3	
GRIP adjustment for specified future tax consequences to third previous tax year (line V3 **multiplied by** the general rate factor for the tax year 0.6800)			540	0
Total GRIP adjustment for specified future tax consequences to previous tax years: (**add** lines 500, 520, and 540) (if negative, enter "0")				0 W

Enter amount W on line 560 on page 1.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year		0 AA
Eligible dividends paid by the corporation in its last tax year	0 BB	
Excessive eligible dividend designations made by the corporation in its last tax year	0 CC	
Subtotal (line BB **minus** line CC)	0 ▶	0 DD
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)		0 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 on page 1 for post-amalgamation; or
– line 240 on page 1 for post-wind-up.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		0	FF
The corporation's money on hand immediately before the end of its previous/last tax year		0	GG
Unused and unexpired losses at the end of the corporation's previous tax year			
Non-capital losses	0		
Net capital losses	0		
Farm losses	0		
Restricted farm losses	0		
Limited partnership losses	0		
Subtotal	0 ►	0	HH
Subtotal (**add** lines FF, GG, and HH)		0	II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year	0 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	0 KK		
All the corporation's reserves deducted in its previous/last tax year	0 LL		
The corporation's capital dividend account immediately before the end of its previous/last tax year	0 MM		
The corporation's low rate income pool immediately before the end of its previous/last tax year	0 NN		
Subtotal (**add** lines JJ, KK, LL, MM, and NN)	0 ►	0	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")		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 on page 1 for a corporation becoming a CCPC;
- – line 230 on page 1 for post-amalgamation; or
- – line 240 on page 1 for post-wind-up.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

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 4 decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	=	0.6800	QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	0 / 365	=	0.0000	RR
0.70	x	number of days in the tax year in 2011 / number of days in the tax year	0 / 365	=	0.0000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	0 / 365	=	0.0000	TT

General Rate Factor for the tax year (total of lines QQ to TT) 0.6800 UU

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BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	**1000**	7,388,000	6,835,000
Accounts Receivable	1060	4,130,000	6,773,000
Inventories	1120	842,000	1,157,000
Work in progress	1125	9,526,000	8,902,000
Short term investments	1180		1,836,000
Prepaid expenses	1484	686,000	293,000
Manufacturing and processing plant	1682	8,162	
Manufacturing and processing plant	1682	50,563,000	48,887,000
Other long term assets	2420	(953,000)	(2,847,000)
Total assets	**2599**	72,190,162	71,836,000

Liabilities	Code	Current year	Prior year
Bank overdraft	**2600**		
Amounts payable and accrued liabilities	2620	9,637,000	11,693,405
Current portion of long term liability	2920	325,000	325,000
Other current liabilities	2960	281,405	514,000
Deposits received	2961	3,840,000	3,802,000
Long term debt	3140	23,743,000	23,943,000
Deferred income	3220		48,000
Other long term liabilities	3320	938,000	840,000
Total liabilities	**3499**	38,764,405	41,165,405

Equity	Code	Current year	Prior year
Common shares	**3500**	27,140,206	27,140,206
Retained earnings / deficit	**3600**	6,285,551	3,530,389
Total equity	**3620**	33,425,757	30,670,595
Total liabilities and equity	**3640**	72,190,162	71,836,000

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	**3660**	3,530,389	906,783
Net income / loss	**3680**	2,755,162	2,623,606
Total retained earnings	**3849**	6,285,551	3,530,389

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INCOME STATEMENT INFORMATION

Schedule 125

Details

Operating name, if different from the corporations' legal name

0001 ______

Description of operation, if filing multiple Schedules 125

0002 ______

Revenue	Code	Current year	Prior year
Trade sales of goods and services	**8000**		
Processing revenue	8044	14,741,000	15,072,000
Total sales of goods and services	**8089**	14,741,000	15,072,000
Other revenue	8230	954,000	1,165,000
Total revenue	**8299**	15,695,000	16,237,000

Cost of sales	Code	Current year	Prior year
Opening inventory	**8300**		
Cost of sales	**8518**		
Gross profit / loss (item 8089 - item 8518)	**8519**	14,741,000	15,072,000

Operating expenses	Code	Current year	Prior year
Advertising and promotion	8520	63,000	72,000
Meals and entertainment	8523	45,000	30,000
Amortization of tangible assets	8670	(8,169)	
Amortization of tangible assets	8670	4,258,007	4,082,044
Interest on mortgages	8713	1,490,000	1,634,000
Collection and credit costs	8717	1,853,000	1,750,000
Office expenses	8810	2,017,000	2,075,050
Rental	8910	270,000	270,000
Repairs and maintenance	8960	2,208,000	1,832,300
Property taxes	9180	246,000	260,000
Total operating expenses	**9367**	12,441,838	12,005,394
Total expenses	**9368**	12,441,838	12,005,394
Net non-farming income	**9369**	3,253,162	4,231,606

Farming revenue	Code	Current year	Prior year
Grains and oilseeds	**9370**		
Total farm revenue	**9659**		

Farming expenses	Code	Current year	Prior year
Crop expenses	**9660**		
Total farm expenses	**9898**		
Net farm income	**9899**		
Net income / loss before taxes and extraordinary items	**9970**	3,253,162	4,231,606

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

	Code		Current year		Prior year
Extraordinary items	**9975**	-	(1,972,000)	-	
Legal settlements	**9976**	-		-	
Unrealized gains / losses	**9980**	+		+	
Unusual items	**9985**	-		-	
Current income taxes	**9990**	-	2,470,000	-	1,608,000
Future income tax provision	**9995**	-		-	
Total - Other comprehensive income	**9998**	+		+	
Net income / loss after taxes and extraordinary items	**9999**	=	2,755,162	=	2,623,606

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Schedule 141
Code 0801

NOTES CHECKLIST

- 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	[X] Yes	[ ] No
Is the accountant connected* with the corporation?	097	[ ] Yes	[X] No

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note
If the accountant does not have a professional designation or is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4 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	[ ] Yes	[X] No

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	[ ]
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	[X] Yes	[ ] No

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost?	102	[ ] Yes	[ ] No
Has there been a change in accounting policies since the last return?	103	[ ] Yes	[ ] No
Are subsequent events mentioned in the notes?	104	[ ] Yes	[ ] No
Is re-evaluation of asset information mentioned in the notes?	105	[ ] Yes	[ ] No
Is contingent liability mentioned in the notes?	106	[ ] Yes	[ ] No
Is information regarding commitments mentioned in the notes?	107	[ ] Yes	[ ] No

Does the corporation have investments in joint venture(s) or partnership(s)?	108	[ ] Yes	[X] No

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)?	109	[ ] Yes	[ ] No

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ONTARIO CORPORATION TAX CALCULATION

SCHEDULE 500

- Use this schedule if the corporation had a permanent establishment (as defined in Regulation 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 income tax

Ontario taxable income *	5,412,058	A
Ontario basic income tax: amount A multiplied by 14 %	757,688	B

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 B on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 on page 8 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, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 2 - 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)			5,412,058	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)			5,412,058	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	500,000 / 500,000 =	500,000	3
Enter the least of amounts 1, 2, and 3			500,000	C
Ontario domestic factor:	Ontario taxable income * / taxable income earned in all provinces and territories **	5,412,058 / 5,412,058 =	1.00000	D
Ontario small business income (amount C **multiplied** by amount D)			500,000	E
OSBD rate for the year		8.5 %		
Ontario small business deduction (amount E **multiplied** by OSBD rate for the year)			42,500	F

Enter amount F on line 402 of Schedule 5.

* Enter amount A from Part 1.

** Includes the offshore jurisdictions for Nova Scotia, and Newfoundland and Labrador.

Part 3 - 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*.

Adjusted taxable income *	5,412,058 G	
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	H	
Aggregate adjusted taxable income (amount G **plus** amount H)	5,412,058 ▶	5,412,058 I
Deduct:		
Ontario business limit		500,000
Subtotal (amount I **minus** Ontario business limit) (if negative, enter "0" on this line and on line M)		4,912,058 J
Small business surtax rate for the year	4.25 %	
Multiply: Line J x small business surtax rate for the year =		208,762 K
Amount K 208,762 x Ontario small business income (amount E in Part 2) / 500,000	500,000 / 500,000 =	208,762 L
Ontario surtax re Ontario small business deduction: lesser of amount L and OSBD (amount F in Part 2)		42,500 M

Enter amount M 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 4 - Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and you are claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Amount C in Part 2			500,000	N
Surtax payable (amount M in Part 3) / Ontario domestic factor (amount D in Part 2) x 8.5 %	42,500 / 1.00000 x 8.5 %	=	500,000	O
Ontario adjusted small business income (amount N **minus** amount O) (if negative, enter "O")				P

Enter amount P on line R in Part 5 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 - 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 in Part 3 of Schedule 17		Q		
Deduct:				
Ontario adjusted small business income (amount P in Part 4)		R		
Subtotal (amount Q **minus** amount R) (if negative, enter "0")		S		
OSBD rate for the year	8.5 %			
Amount S **multiplied** by the OSBD rate for the year				T
Ontario domestic factor (amount D in Part 2)			1.00000	U
Ontario credit union tax reduction (amount T **multiplied** by amount U)				V

Enter amount V on line 410 on Schedule 5

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SCHEDULE 501
Code 0901

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

- 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.
- 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
Newmarket Hydro Holdings Inc	86514 2632 RC 0001	2009/12/31	0
Unipower Holdings Ltd	86553 9399 RC 0001	2009/12/31	0
1443393 Ontario Inc	89239 7613 RC 0001	2009/12/31	0
1443394 Ontario Inc	86553 9191 RC 0001	2009/12/31	0
1443396 Ontario Inc	86553 8995 RC 0001	2009/12/31	0
1443397 Ontario Inc	89239 7217 RC 0001	2009/12/31	0
1443398 Ontario Inc	86553 8797 RC 0001	2009/12/31	0
1402318 Ontario Inc	86709 9772 RC 0001	2009/12/31	0
		Total 500	

Enter the total adjusted taxable income from line 500 on line H in Part 3 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 before January 1, 2009, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada reported on line 10 (or line 20 if applicable) on the *Ontario CT23 Corporations Tax and Annual Return*, or the *Ontario Corporations Tax Return CT8*, whichever is applicable.
- 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
Code 0901

ONTARIO CORPORATE MINIMUM TAX

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 56 of the *Taxation Act*, 2007 (Ontario).
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the year is still required to file this schedule if it is deducting a CMT credit or it has a CMT credit carryforward, a CMT loss carryforward, or a current year CMT loss.
- A corporation that has special additional tax on life insurance corporations (SAT) payable in the 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 as per section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation as per section 130.1 of the federal Act;
  3) a deposit insurance corporation as per section 137.1 of the federal Act;
  4) a congregation or business agency as per section 143 of the federal Act;
  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

The corporation is subject to CMT if the total assets exceed $5,000,000 or the total revenue exceeds $10,000,000.

Total assets of the corporation*	112	72,190,162	
Share of total assets from partnership(s) and joint venture(s)**	114		
Total assets of associated corporations (amount from line 450 on Schedule 511, *Ontario Corporate Minimum Tax – Total Assets and Revenue for Associated Corporations)*	116		
Total assets		72,190,162 ▶	72,190,162
Total revenue of the corporation***	142	15,695,000	
Share of total revenue from partnership(s) and joint venture(s)***	144		
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146		
Total revenue		15,695,000 ▶	15,695,000

* 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.

** 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.

*** **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 by 365 and **divide** by the number of days in the tax year.
- 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.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements*			210	2,755,162
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	2,470,000		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends paid/payable to shareholders (other than dividends paid by credit unions)	230			
Other additions:				
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		2,470,000	▶	2,470,000 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, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation)*	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 wind-up under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions:				
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, *Patronage Dividend Deduction*) 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	5,225,162

If the amount on line 490 is positive, 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).

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal Bank Act, adjusted so consolidation and equity methods are not used.
- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation 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, adjusted so consolidation and equity methods are not used.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.
- Corporations that have included the equity method of accounting in net income/loss on line 210 should remove equity losses from corporations on line 224 and equity income from corporations on line 324.
- A corporation's share in a partnership is determined under paragraph 54(5)(b) of the Taxation Act, 2007 (Ontario) and, if the partnership had no income or loss, is calculated as if the partnership's income were $1 million. For a corporation with an indirect interest in a partnership, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act*, 2007 (Ontario).

** A joint election will be considered made under subsection 60(1) of the *Taxation Act*, 2007 (Ontario) if there is an entry at line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

*** A joint election will be considered made under subsection 60(2) of the *Taxation Act*, 2007 (Ontario) if there is an entry at line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

**** A joint election will be considered made under subsection 61(1) of the *Taxation Act*, 2007 (Ontario) if there is an entry at 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 (amount from line 490 in Part 2)		515	5,225,162		
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	5,225,162		
Gross CMT: amount from line 520 x OAF ** x 4 %				540 209,006	
Deduct:					
Foreign tax credit for CMT purposes ***				550	
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")				209,006	D
Deduct:					
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5, *Tax Calculation Supplementary – Corporations)*				757,688	
Net CMT payable (if negative, enter "0")					E

Enter amount E on line 278 of Schedule 5 and complete Part 4.

* Portion of CMT loss available that exceeds the adjusted net income for the tax year from business(es) continued from before the acquisition of control. See subsection 58(3) of the Taxation Act, 2007 (Ontario).

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21, Federal and Provincial/Territorial Foreign Income Tax Credits and Federal Logging Tax Credit 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 line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year*				G
Deduct:				
CMT credit expired*	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)			620	
Add:				
CMT credit carryforward balances transferred on an amalgamation or the wind-up of a subsidiary (see note below)			650	
Subtotal: CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				H
Deduct:				
CMT credit deducted in the current tax year (amount P in Part 5)				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, *Ontario Special Additional Tax on Life Insurance Corporations (SAT)*)				
Subtotal				K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	L

* For the first 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 ending in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		757,688		
CMT after foreign tax credit deduction (amount D from Part 3)	209,006 1			
Gross SAT (amount from line 460 in Part 6 of Schedule 512)	2			
Deduct: The greater of amounts 1 and 2:		209,006		
Subtotal (if negative, enter "0")		548,682	548,682	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		757,688		
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")		757,688	757,688	O
CMT credit deducted in the current tax year: least of amounts M, N, and O.				P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☐

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the *Taxation Act, 2007* (Ontario).

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if you are reporting a CMT credit carryforward at the beginning of the tax year on line 620, or a CMT credit carryforward transferred on an amalgamation or the wind-up of a subsidiary on line 650. For more information on how to complete this part, see the T2 Corporation – Income Tax Guide.

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).

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year 2001/12/31	681
8th previous tax year 2002/12/31	682
7th previous tax year 2003/12/31	683
6th previous tax year 2004/12/31	684
5th previous tax year 2005/12/31	685
4th previous tax year 2006/12/31	686
3rd previous tax year 2007/04/30	687
2nd previous tax year 2007/12/31	688
1st previous tax year 2008/12/31	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**) 760 ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) 770 ______ T

* For the first 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 ending 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 you are reporting a CMT loss carryforward at the beginning of the tax year on line 720 or a CMT loss transferred on an amalgamation on line 750. For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

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).

Year of origin	Balance earned in a tax year ending before March 24, 2007 *	Balance earned in a tax year ending after March 23, 2007 **
10th previous tax year	810	820
9th previous tax year 2001/12/31	811	821
8th previous tax year 2002/12/31	812	822
7th previous tax year 2003/12/31	813	823
6th previous tax year 2004/12/31	814	824
5th previous tax year 2005/12/31	815	825
4th previous tax year 2006/12/31	816	826
3rd previous tax year 2007/04/30	817	827
2nd previous tax year 2007/12/31	818	828
1st previous tax year 2008/12/31		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 24, 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 10 tax years that ended after March 23, 2007, and has not been deducted.

*** The total of these 2 columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 515
Code 0901

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

- Complete this schedule for a corporation other than a financial institution with a permanent establishment in Ontario at any time in the tax year. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations*. File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:

1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
2) a credit union;
3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
4) a family farm corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario);
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 *Income Tax Act*.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	64,541,757		
Add:				
Accumulated other comprehensive income at the end of the year	105			
Subtotal		64,541,757	64,541,757	A
Deduct:				
Amount B from Part 1 of Schedule 33	110			
Amount on line 490 from Part 2 of Schedule 33	115	2,896,000		
Subtotal		2,896,000	2,896,000	B
Taxable capital (amount A **minus** amount B) (if negative, enter "0")			120	61,645,757

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 ☐ 2 No ☒

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33)	200	61,645,757	x $15,000,000 = **Capital deduction**	220	15,000,000
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *	210	61,645,757			

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act*, 2007 (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516) / Ontario allocation factor (OAF) (amount I in Part 3)	300	OAF	= **Capital deduction**	305

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies	**320**	61,645,757	
Deduct:			
Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2)		15,000,000	B
Net amount (line 320 **minus** amount B) (if negative, enter "0")		46,645,757	C

Amount C 46,645,757 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) 365 / 365 X 0.00225 = 104,953 D

Amount C 46,645,757 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) ____ / 365 X 0.00150 = ____ E

Subtotal (amount D **plus** amount E) 104,953 F

Amount F 104,953 x OAF (amount on line I) 1.00000 = 104,953 G

Amount G 104,953 x (Number of days in the tax year * / 365) 365 / 365 = 104,953 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**	104,953	

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** ____ / Ontario labour cost** **410** ____ = ____ **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% x Amount H from Part 3 = 104,953

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)

S515Supp

Taxable capital of associated corporations other than financial institutions

- Complete this worksheet to calculate taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year.

Name of each associated corporation	Business number	Taxable capital or taxable capital employed in Canada
Newmarket - Tay Power Distribution Ltd	86907 7925 RC 0001	61,645,757
	RC	
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year (Enter on line 210 in Part 2 of Schedule 515)		61,645,757

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SCHEDULE 524
Code 0901

ONTARIO SPECIALTY TYPES

- Use this schedule to identify the specialty type of a corporation carrying on business in the province of Ontario through a permanent establishment if:
  - its tax year includes January 1, 2009;
  - the tax year is the first year after incorporation or an amalgamation; or
  - there is a change to the specialty type.
- If none of the listed specialty types applies, tick box 99 "Other."
- Unless otherwise noted, references to sections, subsections, and clauses are from the *Taxation Act, 2007* (Ontario).

Specialty types

100 Identify the specialty type that applies to your corporation:

- ☐ 01 Family farm corporation – See subsection 64(3).
- ☐ 02 Family fishing corporation – See subsection 64(3).
- ☐ 03 Mortgage investment corporation – See subsection 130.1(6) of the federal *Income Tax Act*.
- ☐ 04 Credit union – See subsection 137(6) of the federal Act.
- ☐ 06 Bank – See subsection 248(1) of the federal Act.
- ☐ 08 Financial institution prescribed by regulation only – See clause 66(2)(f).
- ☐ 09 Registered securities dealer – See subsection 248(1) of the federal Act.
- ☐ 10 Farm feeder finance co-operative corporation
- ☐ 11 Insurance corporation – See subsection 248(1) of the federal Act.
- ☐ 12 Mutual insurance – See subsection 27(2) of the *Taxation Act, 2007* (Ontario) and paragraph 149(1)(m) of the federal Act.
- ☐ 13 Specialty mutual insurance
- ☐ 14 Mutual fund corporation – See subsection 131(8) of the federal Act.
- ☐ 15 Bare trustee corporation
- ☐ 16 Professional corporation (incorporated professional only) – See subsection 248(1) of the federal Act.
- ☐ 17 Limited liability corporation
- ☐ 18 Generator of electrical energy for sale, or producer of steam for use in the generation of electrical energy for sale – See subsection 33(7).
- ☒ 19 Hydro successor, municipal electrical utility, or subsidiary of either – See subsection 91.1(1) and section 88 of the *Electricity Act, 1998* (Ontario).
- ☐ 20 Producer and seller of steam for uses other than for the generation of electricity – See subsection 33(7).
- ☐ 21 Mining corporation
- ☐ 22 Non-resident corporation
- ☐ 99 Other (if none of the previous descriptions apply)

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SCHEDULE 546
Code 0901

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the *Business Corporations Act* (BCA) or *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the Ontario *Corporations Information Act*.
- Complete Parts 1 to 4. Complete Parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up to date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Newmarket - Tay Power Distribution Ltd

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent	**120** Ontario Corporation No.
Ontario	2007/04/30	1800410

Part 2 – Head or registered office address: (P.O. box not acceptable)

200 Care of (if applicable)

210 Street number	**220** Street name	**230** Suite number
590	Steven Court	

240 Additional address information

250 Municipality (e.g., city, town)	**260** Province	**270** Country	**280** Postal code
Newmarket	ON	CA	L3Y 6Z2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS with respect to names, addresses for service, and the date elected/appointed and date ceased of the directors and five most senior officers, or the corporation's mailing address or language of preference? Obtain a Corporation Profile Report to review the information shown for the corporation on the public record maintained by the MGS. For more information, visit **www.ServiceOntario.ca**.

300 [ ] 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 Last name	**451** First name	**454** Middle name(s)
Clinton	Iain	

460 2 Please enter one of the following numbers in this box for the above-named person: enter **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 ☐ Please enter one of the following numbers in this box:
1 – Show no mailing address on the MGS public record.
2 – The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 – The corporation's complete mailing address is as follows:

510 Care of (if applicable)		
520 Street number	**530** Street name	**540** Suite number
550 Additional address information		

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 ☐ Indicate your language preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communication with the corporation. This may be different from line 990 on the T2 return.

Instalments

Federal tax instalments

Instalment base

Year-end	Estimate for current year 2010/12/31	First instalment base 2009/12/31	Second instalment base 2008/12/31
Taxable income		5,412,058	4,426,853
Base amount of Part I tax		2,056,582	1,682,204
Corporate surtax			
Recapture of investment tax credit			
Refundable tax on CCPC's investment income			
Small business deduction			
Federal tax abatement		541,206	442,685
Manufacturing and processing profits deduction			
Foreign tax credits			
Tax reductions		487,085	376,283
Political contribution tax credit			
Investment tax credit			
Other credits			
Part I tax payable		1,028,291	863,236
Part I.3 tax payable			
Part VI tax payable			
Part VI.1 tax payable			
Part XIII.1 tax payable			
Net provincial or territorial tax payable (excluding Ontario)			
Ontario - Single administration			
Income tax payable		757,688	619,759
Corporate minimum tax payable			
Capital tax payable		104,953	128,423
Ontario special additional tax on life insurance corporations			
Total tax payable		1,890,932	1,611,418
Days in taxation year	365	365	365
Tax payable adjusted for short taxation years		1,890,932	1,611,418
Estimated credits for the current year:			
Investment tax credit refund			
Dividend refund			
Other federal credits			
Other provincial credits			
Total estimated credits			
Instalment base (excludes federal and/or provincial component on or below the $3,000 threshold)		1,890,932	1,611,418
Monthly payment		157,578	134,285

Instalment payment options

- ☐ 1. based on estimated taxes for the current year
- ☐ 2. based on the first instalment base
- ☒ 3. based on the first and second instalment base
- ☐ 4. instalments are not required

Does the corporation qualify for quarterly Instalments*? ☐ Yes ☐ No

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible

Instalment payments

Date	Instalments required	Instalments paid	Instalments payable
2010/01/31	134,285		
2010/02/28	134,285		
2010/03/31	162,236		
2010/04/30	162,236		
2010/05/31	162,236		755,278
2010/06/30	162,236		162,236
2010/07/31	162,236		162,236
2010/08/31	162,236		162,236
2010/09/30	162,236		162,236
2010/10/31	162,236		162,236
2010/11/30	162,236		162,236
2010/12/31	162,236		162,236
Total	1,890,930		1,890,930

Summary

Tax Summary

Corporation name: Newmarket - Tay Power Distribution Ltd

Tax year ending 2009/12/31

Taxable income

Net income for tax purposes		5,412,058
Charitable donations and gifts	-	
Taxable dividends	-	
Losses of prior years	-	
Other adjustments	±	
Taxable income	=	5,412,058

Part I tax

38% of taxable income			2,056,582
Surtax		+	
Recapture of investment tax credit		+	
Refundable tax on CCPC investment income		+	
Active business income	5,412,058		
Small business deduction		-	
Federal tax abatement		-	541,206
Manufacturing and processing deduction		-	
Additional deduction - credit unions		-	
Foreign tax credits		-	
Investment tax credit		-	
Other deductions and credits		-	487,085
Part I tax		=	1,028,291

Tax payable

Part I tax			1,028,291
Taxable dividends received			
GRIP at the end of the tax year	8,997,323		
LRIP at the end of the tax year			
Part III.1 tax		+	
Part IV tax		+	
Other federal tax payable		+	
Subtotal		=	1,028,291
Provincial and territorial tax (except AB,QC)		+	862,641
Provincial tax on large corporations (NB,NS)		+	
Tax payable		+	1,890,932
Tax instalments paid		-	
Investment tax credit refund		-	
Taxable dividends paid			
Dividend refund		-	
Other refundable credits		-	
Balance owing (refund) on federal return		=	1,890,932
Provincial income tax (AB,QC)			
Capital and other provincial taxes		+	
Tax instalments and credits		-	
Other provincial taxes		=	
Total balance owing (refund)			1,890,932

Provincial tax

	% Provincial allocation	Taxable income	Income tax	Capital and other provincial taxes	Tax instalments and credits	Net provincial tax
Newfoundland						
Prince Edward Island						
Nova Scotia						
New Brunswick						
Ontario	100.0000	5,412,058	862,641			862,641
Manitoba						
Saskatchewan						
British Columbia						
Yukon Territory						
Northwest Territories						
Nunavut						
Schedule 5 provincial tax payable			862,641			
Alberta						
Québec						
Totals			862,641			862,641

Loss continuity

	Current year carry back	Carryforward end of year
Capital		
Non-capital		
Farm		
Restricted farm		
Limited partnership		
Listed personal property		

Other carryforwards

Capital dividend account	
Refundable dividend tax on hand (net of dividend refund)	
Unused Part 1.3 tax credit	
Unused surtax credits	
Foreign business tax credits	
Donations and gifts	
Investment tax credits	
Ontario S510 (CMT) losses	
Ontario S510 (CMT) credit	

5Year

5 Year Tax Summary

Years Ending:	2009/12/31	2008/12/31	2007/12/31	2007/04/30	2006/12/31
Taxable income					
Net Income for tax purposes	5,412,058	4,426,853	3,392,447	2,225,492	6,014,886
Charitable donations and gifts	-	-	-	-	-
Taxable dividends	-	-	-	-	-
Losses of other years	-	-	-	-	-
Other adjustments	±	±	±	±	±
Taxable income	= 5,412,058	= 4,426,853	= 3,392,447	= 2,225,492	= 6,014,886
Active business income	5,412,058	4,426,853	3,392,447	2,225,492	6,014,886
Part I tax					
38% of taxable income	2,056,582	1,682,204	1,289,130	845,687	2,285,657
Surtax	+	+	+ 37,995	+ 24,926	+ 67,367
Recapture of investment tax credit	+	+	+	+	+
Refundable tax on CCPC investment income	+	+	+	+	+
Small business deduction	-	-	-	-	- 48,000
Federal tax abatement	- 541,206	- 442,685	- 339,245	- 222,549	- 601,489
Manufacturing and processing deduction	-	-	-	-	-
Additional deduction - credit unions	-	-	-	-	-
Foreign tax credits	-	-	-	-	-
Resource deduction		-	-	-	-
Political contribution tax credit		-	-	-	-
Investment tax credit	-	-	-	-	-
Other deductions and credits	- 487,085	- 376,283	- 237,471	- 155,784	- 400,042
Part I tax	= 1,028,291	= 863,236	= 750,409	= 492,280	= 1,303,493
Tax payable					
Part I tax	1,028,291	863,236	750,409	492,280	1,303,493
Part I.3 tax		+	+	+	+
Part III.1 tax payable	+	+	+	+	+
Part IV tax	+	+	+	+	+
Other federal tax payable	+	+	+	+	+
Subtotal	= 1,028,291	= 863,236	= 750,409	= 492,280	= 1,303,493
Provincial and territorial tax (except AB,QC)	+ 862,641	+	+	+	+
Provincial tax on large corporations (NB,NS)	+	+	+	+	+
Tax payable	= 1,890,932	= 863,236	= 750,409	= 492,280	= 1,303,493
Tax instalments made	-	- 2,160,000	-	- 500,000	- 1,330,493
Investment tax credit refund	-	-	-	-	-
Dividend refund	-	-	-	-	-
Other refundable credits	-	-	-	-	-
Balance owing (refund)	= 1,890,932	= (1,296,764)	= 750,409	= (7,720)	= (27,000)
Provincial income tax (AB,QC)		619,759	474,943	311,569	842,084
Capital and other provincial taxes	+	+ 128,423	+ 99,718	+ 40,734	+ 135,924
Tax instalments and credits	-	-	-	- 400,000	- 979,930
Other provincial taxes	=	= 748,182	= 574,661	= (47,697)	= (1,922)
Total taxes owing (refund)	1,890,932	(548,582)	1,325,070	(55,417)	(28,922)

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T2 CORPORATION INCOME TAX RETURN

Schedule 200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in 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, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the T2 Corporation – Income Tax Guide (T4012).

055 Do not use this area

Identification

Business number (BN) 001 86907 7925 RC 0001

Corporation's name

002 Newmarket - Tay Power Distribution Ltd

Address of head office

Has this address changed since the last time you filed your T2 return? 010 ☐ Yes ☒ No

(If **yes**, complete lines 011 to 018)

011 590 Steven Court

012

City: 015 Newmarket — Province, territory, or state: 016 ON

Country (other than Canada): 017 — Postal code/Zip code: 018 L3Y 6Z2

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 Yes ☐ No ☒

(If **yes**, complete lines 021 to 028)

021 c/o

022 590 Steven Court

023

City: 025 Newmarket — Province, territory, or state: 026 ON

Country (other than Canada): 027 — Postal code/Zip code: 028 L3Y 6Z2

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? 030 ☐ Yes ☒ No

(If **yes**, complete lines 031 to 038)

031 590 Steven Court

032

City: 035 Newmarket — Province, territory, or state: 036 ON

Country (other than Canada): 037 — Postal code/Zip code: 038 L3Y 6Z2

040 Type of corporation at the end of the tax year

1 ☒ Canadian-controlled private corporation (CCPC)

2 ☐ Other private corporation

3 ☐ Public corporation

4 ☐ Corporation controlled by a public corporation

5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change 043

To which tax year does this return apply?

From 060 2008/01/01 to 061 2008/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 ☐ Yes ☒ No

If **yes**, provide the date control was acquired 065

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? 066 ☐ Yes ☒ No

Is the corporation a professional corporation that is a member of a partnership? 067 ☐ Yes ☒ No

Is this the first year of filing after:

Incorporation? 070 ☐ Yes ☒ No

Amalgamation? 071 ☐ Yes ☒ No

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 ☐ Yes ☒ No

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 ☐ Yes ☒ No

Is this the final return up to dissolution? 078 ☐ Yes ☒ No

Is the corporation a resident of Canada? 080 ☒ Yes ☐ No

If **no**, give the country of residence on line 081 and complete and attach Schedule 97. 081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 ☐ Yes ☒ No

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085 1 ☐ Exempt under paragraph 149(1)(e) or (l)

2 ☐ Exempt under paragraph 149(1)(j)

3 ☐ Exempt under paragraph 149(1)(t)

4 ☐ Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules - Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **Yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		-----
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
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?	255		92 *

*** We do not print this schedule.**

Attachments - Continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	258	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☐	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☐	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54

Additional information

Is the corporation inactive? **280** 1 Yes ☐ 2 No ☒

Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers) **281** 1 Yes ☐ 2 No ☒

What is the corporation's major business activity? **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	Electrcity Distribution	285	100.000	%
286		287		%
288		289		%

Did the corporation immigrate to Canada during the tax year? **291** 1 Yes ☐ 2 No ☒

Did the corporation emigrate from Canada during the tax year? **292** 1 Yes ☐ 2 No ☒

Do you want to be considered as a quarterly instalment remitter if you are eligible? **293** 1 Yes ☐ 2 No ☐

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible **294**

If the corporation's major business activity is construction, did you have any sub-contractors 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	4,480,408 A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal			▸	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				4,480,408 C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360	4,480,408
Income exempt under paragraph 149(1)(t)			370	
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	4,480,408 A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632 on page 7, **minus** 3 times the amount on line 636 on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	4,480,408 B

Calculation of the business limit:
For all CCPCs, calculate the amount at line 4 below.

\$300,000 x	Number of days in the tax year in 2006 / Number of days in the tax year	/ 366	=		1
\$400,000 x	Number of days in the tax year after 2006 and before January 1, 2009 / Number of days in the tax year	366 / 366	=	400,000	2
\$500,000 x	Number of days in the tax year after 2008 / Number of days in the tax year	/ 366	=		3
	Add amounts at lines 1, 2 and 3			400,000	4

Business limit (see notes 1 and 2 below)	410	400,000 C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 400,000 X (415 11,250 D) / 11,250 = 400,000 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425	0 F

Small business deduction

Amount A, B, C, or F whichever is the least ____ x (Number of days in the tax year before January 1, 2008 ____ / Number of days in the tax year 366) x 16% = ____ 5

Amount A, B, C, or F whichever is the least ____ x (Number of days in the tax year after Dec.31, 2007 366 / Number of days in the tax year 366) x 17% = ____ 6

Total of amounts 5 and 6 - enter on line 9 of page 7	430	0 G

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)]			435	H
Amount H ______ x	Number of days in the tax year in 2006 / Number of days in the tax year	______ / 366	x 5% = ______	I
Amount H ______ x	Number of days in the tax year in 2007 / Number of days in the tax year	______ / 366	x 7% = ______	J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – total of amounts I and J	438	K

Enter amount K on line 10 of page 7.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3			4,480,408	A
Lesser of amounts V and Y from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Taxable resource income from line 435 on page 4		D		
Amount used to calculate the credit union deduction (from Schedule 17)		E		
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 of page 6		G		
Total of amounts B, C, D, E, F, and G		▶		H
Amount A **minus** amount H (if negative, enter "0")			4,480,408	I

Amount I 4,480,408 x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	______ / 366	x 7% =		J
Amount I 4,480,408 x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	366 / 366	x 8.5% =	380,835	K
Amount I 4,480,408 x	Number of days in the tax year after Dec. 31, 2008 and before January 1, 2010 / Number of days in the tax year	______ / 366	x 9% =		L

General tax reduction for Canadian-controlled private corporations - total of amounts J, K, and L	380,835	M

Enter amount M on line 638 of page 7.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3 (for tax years starting after May 1, 2006, Amount Z on page 3)				N
Lesser of amounts V and Y from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Taxable resource income from line 435 on page 4		Q		
Amount used to calculate the credit union deduction (from Schedule 17)		R		
Total of amounts O, P, Q, and R		▶		S
Amount N **minus** amount S (if negative, enter "0")				T

Amount T ______ x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	______	x 7% =		U
Amount T ______ x	Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year	______	x 8.5% =		V
Amount T ______ x	Number of days in the tax year after Dec. 31, 2008 and before Jan. 1, 2010 / Number of days in the tax year	______	x 9% =		W

General tax reduction - total of amounts U, V and W		X

Enter amount X on line 639 of page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7)	440	X 26 2/3 % =			A
Foreign non-business income tax credit from line 632 on page 7					
Deduct:					
Foreign investment income (from Schedule 7)	445	X 9 1/3 % =			
		(if negative, enter "0")			B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360 on page 3			4,480,408		
Deduct:					
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least					
Foreign non-business income tax credit from line 632 of page 7	x 25/9 =				
Foreign business income tax credit from line 636 of page 7	x 3 =				
			4,480,408	X 26 2/3% = 1,194,775	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			873,679		
Deduct: Corporate surtax from line 600 of page 7					
Net amount			873,679	873,679	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least			450	0	F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			
				G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
				H
Refundable dividend tax on hand at the end of the tax year - Amount G **plus** amount H		485	0	

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3		X 1/3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 of page 8)			0	

Part I tax

Base amount of Part I tax

taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38%			550	1,702,555	A

Corporate surtax calculation

Base amount from line A above		1,702,555	1
Deduct:			
10% of taxable income (line 360 or amount Z, whichever applies) from page 3		448,041	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28% of taxable income from line 360 on page 3	a		
28% of taxed capital gains	b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	873,679 c		
Total of lines 2 to 6		448,041	7
Net amount (line 1 **minus** line 7)		1,254,514	8

Corporate surtax*

Line 8 1,254,514 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366) x 4% = 600 ______ B

*The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 602 ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	4,480,408		
Deduct: Amount on line 400, 405, 410, or 425 of page 4, whichever is the least			
Net amount	4,480,408 ▶	4,480,408	ii

Refundable tax on CCPC's investment income – 6 2/3% of whichever is less: amount i or ii	604		D
Subtotal (**add** lines A, B, C, and D)		1,702,555	E

Deduct:

Small business deduction from line 430 on page 4			9	
Federal tax abatement	608	448,041		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
(taxed capital gains 624 ______)				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
Resource deduction from line 438 on page 4			10	
General tax reduction for CCPCs from amount M on page 5	638	380,835		
General tax reduction from amount X on page 5	639			
Federal logging tax credit from Schedule 21	640			
Federal political contribution tax credit	644			
Federal political contributions 646 ______				
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652			
Subtotal		828,876 ▶	828,876	F
Part I tax payable – Line E **minus** line F			873,679	G

Enter amount G on line 700 of page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	873,679
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		873,679

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		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770		873,679 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	2,160,000	
Total credits	890	2,160,000	2,160,000 B

Refund Code **894** 2 Overpayment 1,286,321

Balance (line A minus line B) (1,286,321) I

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment **898**

Direct Deposit Request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information **910** ______ Branch number

914 ______ Institution number **918** ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? **896** 1 Yes ☐ 2 No ☒ NA ☐

Certification

I, **950** Clinton (Last name) **951** Iain (First name) **954** Chief Financial Officer (Position, office or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2010/05/26 (Date) ______ Signature of the authorized signing officer of the corporation **956** (905) 953-8548 (Telephone number)

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. **957** 1 Yes ☐ 2 No ☒

958 Iain Clinton, CA (Name) **959** (905) 953 - 8548 (Telephone number)

Language of correspondence - Langue de correspondance

990 Language of choice/Langue de choix 1 English / Anglais ☒ 2 Français / French ☐

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the *T2 Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box.
  You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements			**A**	2,623,606
Add:				
Provision for income taxes - current	101	1,608,000		
Amortization of tangible assets	104	4,082,044		
Non-deductible meals and entertainment expenses 30,000 X 50%	121	15,000		
Reserves from financial statements - balance at the end of the year	126	1,138,882		
Total of fields 101 to 199	500	6,843,926	▸	6,843,926
Deduct:				
Capital cost allowance from Schedule 8	403	3,957,636		
Cumulative eligible capital deduction from Schedule 10	405	110,447		
Reserves from financial statements - balance at the beginning of the year	414	919,041		
Total of fields 401 to 499	510	4,987,124	▸	4,987,124
Net income (loss) for income tax purposes - enter on line 300 on page 3 of the T2 return				4,480,408

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CAPITAL COST ALLOWANCE

Schedule 8

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

1 Class 200	2 UCC at start of year 201	3 Cost of additions in the year 203	4 Net adjustments 205	5 Proceeds of dispositions in the year 207	7 Adjustment for additions (1/2 x (col 3 - 5)) 211	8 Base amount for CCA	9 Rate % 212	10 Recapture of CCA 213	11 Terminal loss 215	12 CCA for the year (col 8 x 9 or a lower amount) 217	13 UCC at the end of the year 220
1	35,404,395	635,006			317,503	35,721,898	4			1,428,876	34,610,525
3	6,775					6,775	5			339	6,436
8	2,571,557	65,142			32,571	2,604,128	20			520,826	2,115,873
10	1,379,079	729,426			364,713	1,743,792	30			523,138	1,585,367
17	55,339					55,339	8			4,427	50,912
2	6,815,689					6,815,689	6			408,941	6,406,748
47	9,151,745	4,833,799			2,416,900	11,568,644	8			925,492	13,060,052
45	19,464					19,464	45			8,759	10,705
12	40,131	66,934			33,467	73,598	100			73,598	33,467
13	182,139	37,455			18,728	200,866				31,474	188,120
50		115,512			57,756	57,756	55			31,766	83,746
Totals	55,626,313	6,483,274			3,241,638	58,867,949				3,957,636	58,151,951

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RELATED AND ASSOCIATED CORPORATIONS

Schedule 9

This form is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporation(s)

Name	Country (if not Canada)	Business # (Canadian corporation only)	Code note 1	Common shares		Preferred shares		Book value of capital stock
				# owned	% owned	# owned	% owned	
100	200	300	400	500	550	600	650	700
Newmarket Hydro Holdings Inc		86514 2632 RC 0001	1	930	93.000			3,870,000
Unipower Holdings Ltd		86553 9399 RC 0001	3					
1443393 Ontario Inc		89239 7613 RC 0001	3					
1443394 Ontario Inc		86553 9191 RC 0001	3					
1443396 Ontario Inc		86553 8995 RC 0001	3					
1443397 Ontario Inc		89239 7217 RC 0001	3					
1443398 Ontario Inc		86553 8797 RC 0001	3					
1402318 Ontario Inc		86709 9772 RC 0001	3					
Tay Utility Contracting Inc		86777 9449 RC 0001	3					
Tay Hydro Inc		86863 4528 RC 0001	1	70	7.000			
Township of Tay		NR	3					

Note 1 : Enter the code number of the relationship that applies: 1- Parent 2 - Subsidiary 3 - Associated 4 - Related, but not associated

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CUMULATIVE ELIGIBLE CAPITAL DEDUCTION — Schedule 10

Part 1 - Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	1,577,819	A
Add: Cost of eligible capital property acquired during the taxation year	222					
Other adjustments	226					
Subtotal (line 222 plus line 226)		x 3/4 =		B		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1/2 =		C		
amount B minus amount C (if negative, enter "0")				▶		D
Amount transferred on amalgamation or wind-up of subsidiary				224		E
Subtotal (add amounts A, D, and E)				230	1,577,819	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H			
Other adjustments	246		I			
(add amounts G, H, and I)			x 3/4 =	248		J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)					1,577,819	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business		249				
amount K	1,577,819					
less amount from line 249						
Current year deduction	1,577,819 x 7% =	250	110,447 *			
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			110,447	▶	110,447	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	1,467,372	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		400	1		
Total of all amounts which reduced CEC in the current or prior years under subsection 80 (7)		401	2		
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")		▶	5		
Total of lines 1, 2, and 5			6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409	▶	9		
Line 6 minus line 9 (if negative, enter "0")					O
Line N minus line O (if negative, enter "0")					P
Line 5		x 1/2 =			Q
Line P minus line Q (if negative, enter "0")					R
Amount R		x	66.6667		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

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Schedule 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:
1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction.
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) **025**

Enter the calendar year to which the agreement applies **050** 2008

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? **075** ☐ 1 Yes ☒ 2 No

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300
1	Newmarket - Tay Power Distribution Ltd	86907 7925 RC 0001	1
2	Newmarket Hydro Holdings Inc	86514 2632 RC 0001	1
3	Unipower Holdings Ltd	86553 9399 RC 0001	1
4	1443393 Ontario Inc	89239 7613 RC 0001	1
5	1443394 Ontario Inc	86553 9191 RC 0001	1
6	1443396 Ontario Inc	86553 8995 RC 0001	1
7	1443397 Ontario Inc	89239 7217 RC 0001	1
8	1443398 Ontario Inc	86553 8797 RC 0001	1
9	1402318 Ontario Inc	86709 9772 RC 0001	1
10	Tay Utility Contracting Inc	86777 9449 RC 0001	
11	Tay Hydro Inc	86863 4528 RC 0001	
12	Township of Tay	NR	

Allocate business limit using: ☒ % ☐ $

	Taxation year		4 Business limit for the year (before allocation) $	Allocating business limit		
				5 Percentage of the business limit (%) 350	6 Business limit allocated $ 400	7 Gross Part I.3 tax for business limit reduction
	Start	End				
1	2008/01/01	2008/12/31	400,000	100.000	400,000	110,263
2	2009/01/01	2009/12/31	500,000			
3	2009/01/01	2009/12/31	500,000			
4	2009/01/01	2009/12/31	500,000			

AGREEMENT AMONG ASSOCIATED CCPCs TO ALLOCATE THE BUSINESS LIMIT

	Taxation year		4 Business limit for the year (before allocation) $	Allocating business limit		
				5 Percentage of the business limit (%)	6 Business limit allocated $	7 Gross Part I.3 tax for business limit reduction
	Start	End		350	400	
5	2009/01/01	2009/12/31	500,000			
6	2009/01/01	2009/12/31	500,000			
7	2009/01/01	2009/12/31	500,000			
8	2009/01/01	2009/12/31	500,000			
9	2009/01/01	2009/12/31	500,000			
10						
11						
12						
TOTALS				100.000	A 400,000	110,263

If the taxation year of the corporation filing this form is less than 51 weeks, enter the prorated business limit in this box. $ 400,000

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, 2007, 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 $400,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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PART I.3 TAX ON LARGE CORPORATIONS

Schedule 33

- File this schedule if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Even if there is no Part I.3 tax payable for the days in the tax year that are after 2005, you must still complete this schedule (except parts 5 and 9).
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution", "long-term debt" and "reserves".
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- No Part I.3 tax is payable for a taxation year by a corporation that was:
  1) bankrupt [as defined by subsection 128(3)] at the end of the year;
  2) a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
  3) exempt from tax under section 149 throughout the year on all of its taxable income;
  4) neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
  5) a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
- File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of printing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 - Capital

Add the following amounts at the end of the year:				
Reserves that have not been deducted in computing income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	27,140,206		
Retained earnings	104	3,530,389		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
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		30,670,595	30,670,595	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121			
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				B
Capital for the year (amount A minus amount B) (if negative, enter "0")		190	30,670,595	

PART I.3 TAX ON LARGE CORPORATIONS

Part 2 - Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership	407	
Investment allowance for the year (add lines 401 to 407)	490	

Part 3 - Taxable capital

Capital for the year (line 190)		30,670,595	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500	30,670,595	

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)			Taxable income earned in Canada					Taxable capital employed in Canada
	30,670,595	x	Taxable income earned in Canada	610	4,480,408	=	690	30,670,595
			Taxable income		4,480,408			

Notes: 1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada			701	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711			
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada	713			
Total deductions (add lines 711, 712, and 713)				E
Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0")			790	

PART I.3 TAX ON LARGE CORPORATIONS

Part 5 - Calculation of gross Part I.3 tax

If the tax year starts after 2005, do not complete this part.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		30,670,595
Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36)		50,000,000
Excess of taxable capital employed in Canada over capital deduction	811	

Line 811 ______ x Number of days in the tax year in 2004 / Number of days in the tax year ______ / 366 x 0.002 = ______ F

Line 811 ______ x Number of days in the tax year in 2005 / Number of days in the tax year ______ / 366 x 0.00175 = ______ G

Note: The Part I.3 tax rate is reduced to 0% for the days in the tax year that are after 2005.

Subtotal (add amounts F and G) ______ H

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax as follows:

Amount H ______ X Number of days in the year (______) / 365 = ______ I

Gross Part I.3 tax (amount H or I, whichever applies) 820 ______

Part 6 – Calculation of gross Part I.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies)		30,670,595	J
Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36) 801 50,000,000 x 1/5 =		10,000,000	K
Excess (amount J minus amount K) (if negative, enter "0")		20,670,595	L
Amount L 20,670,595 x 0.00225 =		46,509	M

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax for purposes of the unused surtax credit as follows:

Amount M ______ x Number of days in the year (______) / 365 = ______ N

Gross Part I.3 tax for purposes of the unused surtax credit (amount M or N, whichever applies) 821 46,509

PART I.3 TAX ON LARGE CORPORATIONS

Part 7 - Calculation of current-year surtax credit available

- Corporations can claim a credit against their Part I.3 tax for the amount of Canadian surtax payable for the year. This is called the surtax credit.
- Any unused surtax credit can be carried back three years or carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subsection 181.1(7) when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.

For a corporation that was a non-resident of Canada throughout the year, enter amount **a** or **b** at line O, whichever is less:

a) line 600 from the T2 return		**a**		
b) line 700 from the T2 return		**b**		O

In any other case, enter amount **c** or **d** at line P, whichever is less:

c) line 600 from the T2 return ______ x (line 690 ÷ line 500) =		**c**		
d) line 700 from the T2 return	873,679	**d**		P
Current-year surtax credit available (amount O or P, whichever applies)		**830**		

Part 8 - Calculation of current-year unused surtax credit

Current-year surtax credit available (line 830)		
Less: Gross Part I.3 tax for purposes of the unused surtax credit (line 821)		46,509
Current-year unused surtax credit (if negative, enter "0")	**850**	

Enter this amount at line 600 on Schedule 37.

Part 9 - Calculation of net Part I.3 tax payable

If the tax year starts after 2005, do not complete this part.

Gross Part I.3 tax (line 820)					Q
Deduct:					
Current-year surtax credit applied (line 820 or 830, whichever is less)	**861**				
Unused surtax credit from previous years applied (amount from line 320 on Schedule 37)	**862**				
Subtotal (cannot be more than amount on line 820)					R
Net Part I.3 tax payable (amount Q minus amount R)			**870**		

Enter this amount at line 704 of the T2 return.

Part 10 - Calculation for purposes of the small business deduction

This part is applicable only to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)	30,670,595	S
Deduct:		
Capital deduction claimed for the year (enter $10,000,000)	10,000,000	T
Excess (amount S minus amount T) (if negative, enter "0")	20,670,595	U
Gross Part I.3 tax for purposes of the small business deduction (Amount U x 0.00225)	46,509	V

Enter this amount at line 415 of the T2 return.

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Schedule 36

AGREEMENT AMONG RELATED CORPORATIONS - PART I.3 TAX

- Corporations related at any time in their tax year that ends in the calendar year of the agreement should use this schedule to allocate the capital deduction of $50,000,000 among the members of the related group if:
  - any member applies the surtax credit against Part I.3 tax in a tax year starting before January 1, 2006; or
  - any member wants to carry back an unused surtax credit against Part I.3 tax to a tax year starting before January 1, 2006.
- According to subsection 181.5(7) of the *Income Tax Act*, a Canadian-controlled private corporation is not considered to be related to another corporation for the capital deduction unless it is also associated with that corporation.
- In cases where a related corporation has more than one tax year ending in a calendar year, it has to file this agreement for each of those tax years.
- According to subsection 181.5(5), where a corporation has more than one tax year ending in the same calendar year and is related in two or more of those tax years to another corporation that has a tax year ending in that calendar year, the capital deduction of the first corporation for each such tax year at the end of which it is related to the other corporation is an amount equal to its capital deduction for the first such tax year.
- Any corporation in the related group may file this agreement on behalf of the group. However, if an agreement is not already on file with us when we assess any of the returns for a tax year ending in the calendar year of the agreement, we will ask for one.

Agreement

Date filed (do not use this area) **010**

Is this an amended agreement? **020** ☐ 1 Yes ☒ 2 No

Calendar year to which the agreement applies **030** 2008

Note: This agreement must include all the information indicated below for all members of the related group, including members to which no amount of capital deduction is allocated for the year. However, any member that is exempt from Part I.3 tax under subsection 181.1(3) of the *Income Tax Act* does not have to be included.

Name of each corporation that is a member of the related group 200	Business number (if a corporation is not registered, enter "NR") 300	Allocation of capital deduction for the year $ 400
Newmarket - Tay Power Distribution Ltd	86907 7925 RC 0001	50,000,000
Newmarket Hydro Holdings Inc	86514 2632 RC 0001	0
Unipower Holdings Ltd	86553 9399 RC 0001	0
1443393 Ontario Inc	89239 7613 RC 0001	0
1443394 Ontario Inc	86553 9191 RC 0001	0
1443396 Ontario Inc	86553 8995 RC 0001	0
1443397 Ontario Inc	89239 7217 RC 0001	0
1443398 Ontario Inc	86553 8797 RC 0001	0
1402318 Ontario Inc	86709 9772 RC 0001	0
Tay Utility Contracting Inc	86777 9449 RC 0001	0
Tay Hydro Inc	86863 4528 RC 0001	0
Township of Tay	NR	0
	Total (cannot be more than $50,000,000)	50,000,000

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SHAREHOLDER INFORMATION

Schedule 50

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual or trust) 100	Business Number (If a corporation is not registered, enter "NR") * 200	Social Insurance Number * 300	Trust Number (If a trust number is not available, enter "NA") * 350	Percentage common shares 400	Percentage preferred shares 500
Newmarket Hydro Holdings Inc	86514 2632 RC 0001			93.000	
	RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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BALANCE SHEET INFORMATION

Schedule 100

Assets	Code	Current year	Prior year
Cash and deposits	**1000**	6,835,000	6,633,900
Accounts Receivable	1060	6,773,000	7,214,300
Inventories	1120	1,157,000	995,482
Work in progress	1125	8,902,000	8,069,714
Short term investments	1180	1,836,000	837,106
Prepaid expenses	1484	293,000	379,805
Manufacturing and processing plant	1682	48,887,000	45,946,452
Other long term assets	2420	(2,847,000)	464,109
Total assets	**2599**	71,836,000	70,540,868

Liabilities	Code	Current year	Prior year
Bank overdraft	**2600**		
Amounts payable and accrued liabilities	2620	11,693,405	9,422,905
Current portion of long term liability	2920	325,000	352,586
Other current liabilities	2960	514,000	200,000
Deposits received	2961	3,802,000	4,325,967
Dividends payable	2962		1,665,000
Long term debt	3140	23,943,000	23,978,821
Deferred income	3220	48,000	141,246
Amounts owing to related Canadian parties	3301		1,665,000
Other long term liabilities	3320	840,000	742,354
Total liabilities	**3499**	41,165,405	42,493,879

Equity	Code	Current year	Prior year
Common shares	**3500**	27,140,206	27,140,206
Retained earnings / deficit	**3600**	3,530,389	906,783
Total equity	**3620**	30,670,595	28,046,989
Total liabilities and equity	**3640**	71,836,000	70,540,868

Retained earnings	Code	Current year	Prior year
Retained earnings/deficit-start	**3660**	906,783	
Net income / loss	**3680**	2,623,606	906,783
Total retained earnings	**3849**	3,530,389	906,783

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INCOME STATEMENT INFORMATION

Schedule 125

Details

Operating name, if different from the corporations' legal name

0001 ____________________

Description of operation, if filing multiple Schedules 125

0002 ____________________

Revenue	Code	Current year	Prior year
Trade sales of goods and services	**8000**		
Processing revenue	8044	15,072,000	48,901,994
Total sales of goods and services	**8089**	15,072,000	48,901,994
Investment revenue	8090		307,093
Realized gains / losses on disposal of assets	8210		(1,106,082)
Other revenue	8230	1,165,000	545,993
Total revenue	**8299**	16,237,000	48,648,998

Cost of sales	Code	Current year	Prior year
Opening inventory	**8300**		
Purchases / cost of materials	8320		38,699,759
Cost of sales	**8518**		38,699,759
Gross profit / loss (item 8089 - item 8518)	**8519**	15,072,000	10,202,235

Operating expenses	Code	Current year	Prior year
Advertising and promotion	8520	72,000	
Meals and entertainment	8523	30,000	13,200
Amortization of tangible assets	8670	4,082,044	2,732,316
Interest on mortgages	8713	1,634,000	1,091,120
Collection and credit costs	8717	1,750,000	1,132,815
Office expenses	8810	2,075,050	1,584,852
Rental	8910	270,000	
Repairs and maintenance	8960	1,832,300	1,180,659
Property taxes	9180	260,000	190,206
Total operating expenses	**9367**	12,005,394	7,925,168
Total expenses	**9368**	12,005,394	46,624,927
Net non-farming income	**9369**	4,231,606	2,024,071

Farming revenue	Code	Current year	Prior year
Grains and oilseeds	**9370**		
Total farm revenue	**9659**		

Farming expenses	Code	Current year	Prior year
Crop expenses	**9660**		
Total farm expenses	**9898**		
Net farm income	**9899**		
Net income / loss before taxes and extraordinary items	**9970**	4,231,606	2,024,071

Summary

Complete this section if only one Schedule 125 is filed, Schedule 140 is used to summarize the information from multiple Schedules 125.

Extraordinary items	**9975**	-		-	
Legal settlements	**9976**	-		-	
Unrealized gains / losses	**9980**	+		+	
Unusual items	**9985**	-		-	
Current income taxes	**9990**	-	1,608,000	-	1,117,288
Future income tax provision	**9995**	-		-	
Net income / loss after taxes and extraordinary items	**9999**	=	2,623,606	=	906,783

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Schedule 141
Code 0801

NOTES CHECKLIST

- 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**	☒ Yes	☐ No
Is the accountant connected* with the corporation?	**097**	☐ Yes	☒ No

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note

If the accountant does not have a professional designation or is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4 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	☒
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**	☐ Yes	☒ No

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	☐
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**	☒ Yes	☐ No

If **yes**, complete lines 102 to 107 below:

Are any values presented at other than cost?	**102**	☐ Yes	☒ No
Has there been a change in accounting policies since the last return?	**103**	☐ Yes	☒ No
Are subsequent events mentioned in the notes?	**104**	☒ Yes	☐ No
Is re-evaluation of asset information mentioned in the notes?	**105**	☐ Yes	☒ No
Is contingent liability mentioned in the notes?	**106**	☐ Yes	☒ No
Is information regarding commitments mentioned in the notes?	**107**	☒ Yes	☐ No

Does the corporation have investments in joint venture(s) or partnership(s)?	**108**	☐ Yes	☒ No

If **yes**, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)?	**109**	☐ Yes	☐ No

TaxPaid

Tax instalments paid

Jurisdiction	Description	Date	Amount
Federal			2,160,000
Federal			
		Total	2,160,000

* Enter Québec instalments paid on form CO-1027.VE

Summary by jurisdiction

Federal	2,160,000	Manitoba	
British Columbia		Ontario	
Alberta			
Saskatchewan			

Instalments

Federal tax instalments

Instalment base

	Estimate for current year	First instalment base	Second instalment base
Year-end	2009/12/31	2008/12/31	2007/12/31
Taxable income		4,480,408	3,392,447
Base amount of Part I tax		1,702,555	1,289,130
Corporate surtax			37,995
Refundable tax on CCPC's investment income			
Small business deduction			
Federal tax abatement		448,041	339,245
Manufacturing and processing profits deduction			
Foreign tax credits			
Tax reductions		380,835	237,471
Political contribution tax credit			
Investment tax credit			
Other credits			
Part I tax payable		873,679	750,409
Part I.3 tax payable			
Part VI tax payable			
Part VI.1 tax payable			
Part XIII.1 tax payable			
Net provincial or territorial tax payable (excluding Ontario)			
Ontario - Single administration			
Income tax payable		627,257	
Corporate minimum tax payable			
Capital tax payable		118,966	
Ontario special additional tax on life insurance corporations			
Total tax payable		1,619,902	750,409
Days in taxation year	365	365	245
Tax payable adjusted for short taxation years		1,619,902	1,117,956
Estimated credits for the current year:			
Investment tax credit refund			
Dividend refund			
Other federal credits			
Other provincial credits			
Total estimated credits			
Instalment base (excludes federal and/or provincial component on or below the $3,000 threshold)		1,619,902	1,117,959
Monthly payment		134,992	93,163

Instalment payment options

☐ 1. based on estimated taxes for the current year

☐ 2. based on the first instalment base

☒ 3. based on the first and second instalment base

☐ 4. instalments are not required

Does the corporation qualify for quarterly Instalments*? ☐ Yes ☐ No

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible

Instalment payments

Date	Instalments required	Instalments paid	Instalments payable
2009/01/31	93,163		
2009/02/28	93,163		
2009/03/31	143,358		
2009/04/30	143,358		
2009/05/31	143,358		
2009/06/30	143,358		
2009/07/31	143,358		

Instalments

Federal tax instalments

Date	Instalments required	Instalments paid	Instalments payable
2009/08/31	143,358		
2009/09/30	143,358		
2009/10/31	143,358		
2009/11/30	143,358		
2009/12/31	143,358		
Total	1,619,906		

Summary

Tax Summary

Corporation name Newmarket - Tay Power Distribution Ltd

Tax year ending 2008/12/31

Taxable income

Net income for tax purposes		4,480,408
Charitable donations and gifts	-	
Taxable dividends	-	
Losses of prior years	-	
Other adjustments	±	
Taxable income	=	4,480,408

Part I tax

38% of taxable income			1,702,555
Surtax		+	
Refundable tax on CCPC investment income		+	
Active business income	4,480,408		
Small business deduction		-	
Federal tax abatement		-	448,041
Manufacturing and processing deduction		-	
Additional deduction - credit unions		-	
Foreign tax credits		-	
Resource deduction		-	
Political contribution tax credit		-	
Investment tax credit		-	
Other deductions and credits		-	380,835
Part I tax		=	873,679

Tax payable

Part I tax			873,679
Part I.3 tax (large corporations tax)		+	
Taxable dividends received			
Part IV tax		+	
Other federal tax payable		+	
Subtotal		=	873,679
Provincial and territorial tax (except QC,ON,AB)		+	
Provincial tax on large corporations (NB,NS)		+	
Tax payable		+	873,679
Tax instalments paid		-	2,160,000
Investment tax credit refund		-	
Taxable dividends paid			
Dividend refund		-	
Other refundable credits		-	
Balance owing (refund) on federal return		=	(1,286,321)
Provincial income tax (ON,AB,QC)			627,257
Capital and other provincial taxes		+	118,966
Tax instalments and credits		-	
Other provincial taxes		=	746,223
Total balance owing (refund)			(540,098)

Provincial tax

	% Provincial allocation	Taxable income	Income tax	Capital and other provincial taxes	Tax instalments and credits	Net provincial tax
Newfoundland						
Prince Edward Island						
Nova Scotia						
New Brunswick						
Manitoba						
Saskatchewan						
British Columbia						
Yukon Territory						
Northwest Territories						
Nunavut						
Schedule 5 provincial tax payable						
Ontario	100.0000	4,480,408	627,257	118,966		746,223
Alberta						
Québec						
Totals			627,257	118,966		746,223

Loss continuity

	Current year carry back	Carryforward end of year
Capital		
Non-capital		
Farm		
Restricted farm		
Limited partnership		
Listed personal property		

Other carryforwards

Capital dividend account	
Refundable dividend tax on hand (net of dividend refund)	
Unused Part 1.3 tax credit	
Unused surtax credits	
Foreign business tax credits	
Donations and gifts	
Investment tax credits	
Ontario CMT losses	
Ontario CMT credit	

5Year

5 Year Tax Summary

Years Ending:	2008/12/31	2007/12/31	2007/04/30	2006/12/31	2005/12/31
Taxable income					
Net Income for tax purposes	4,480,408	3,392,447	2,225,492	6,014,886	4,888,672
Charitable donations and gifts	-	-	-	-	- 1,885,000
Taxable dividends	-	-	-	-	-
Losses of other years	-	-	-	-	- 150,000
Other adjustments	±	±	±	±	±
Taxable income	= 4,480,408	= 3,392,447	= 2,225,492	= 6,014,886	= 2,853,672
Active business income	4,480,408	3,392,447	2,225,492	6,014,886	4,888,672
Part I tax					
38% of taxable income	1,702,555	1,289,130	845,687	2,285,657	1,084,395
Surtax	+	+ 37,995	+ 24,926	+ 67,367	+ 31,961
Refundable tax on CCPC investment income	+	+	+	+	+
Small business deduction	-	-	-	- 48,000	-
Federal tax abatement	- 448,041	- 339,245	- 222,549	- 601,489	- 285,367
Manufacturing and processing deduction	-	-	-	-	-
Additional deduction - credit unions	-	-	-	-	-
Foreign tax credits	-	-	-	-	-
Resource deduction	-	-	-	-	-
Political contribution tax credit	-	-	-	-	-
Investment tax credit	-	-	-	-	-
Other deductions and credits	- 380,835	- 237,471	- 155,784	- 400,042	- 199,757
Part I tax	= 873,679	= 750,409	= 492,280	= 1,303,493	= 631,232
Tax payable					
Part I tax	873,679	750,409	492,280	1,303,493	631,232
Part I.3 tax	+	+	+	+	+
Part IV tax	+	+	+	+	+
Other federal tax payable	+	+	+	+	+
Subtotal	= 873,679	= 750,409	= 492,280	= 1,303,493	= 631,232
Provincial and territorial tax (except AB,QC)	+	+	+	+	+
Provincial tax on large corporations (NB,NS)	+	+	+	+	+
Tax payable	= 873,679	= 750,409	= 492,280	= 1,303,493	= 631,232
Tax instalments made	- 2,160,000	-	- 500,000	- 1,330,493	- 1,182,400
Investment tax credit refund	-	-	-	-	-
Dividend refund	-	-	-	-	-
Other refundable credits	-	-	-	-	-
Balance owing (refund)	= (1,286,321)	= 750,409	= (7,720)	= (27,000)	= (551,168)
Provincial income tax (AB,QC)	627,257	474,943	311,569	842,084	399,514
Capital and other provincial taxes	+ 118,966	+ 99,718	+ 40,734	+ 135,924	+ 139,939
Tax instalments and credits	-	-	- 400,000	- 979,930	-
Other provincial taxes	= 746,223	= 574,661	= (47,697)	= (1,922)	= 539,453
Total taxes owing (refund)	(540,098)	1,325,070	(55,417)	(28,922)	(11,715)

Ontario

Ministry of Revenue

Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Newmarket - Tay Power Distribution Ltd	1800410	2008/12/31

Part 1: Calculation of CMT Base

Banks - Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations - Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net income/(loss) (unconsolidated, determined in accordance with GAAP)			2100 ±	2,623,606
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	2101 +			
Provision for deferred income taxes (credits) / benefit of future income taxes	2102 +			
Equity income from corporations	2103 +			
Share of partnership(s)/joint venture(s) income	2104 +			
Dividends received/receivable deductible under fed.s.112	2105 +			
Dividends received/receivable deductible under fed.s.113	2106 +			
Dividends received/receivable deductible under fed.s.83(2)	2107 +			
Dividends received/receivable deductible under fed.s.138(6)	2108 +			
Federal Part VI.1 tax on dividends declared and paid, under fed.s.191.1(1) ______ x 3 =	2109 +			
Subtotal	=		2110 -	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	2111 +	1,608,000		
Provision for deferred income taxes (debits) / cost of future income taxes	2112 +			
Equity losses from corporations	2113 +			
Share of partnership(s)/joint venture(s) losses	2114 +			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	2115 +			
Subtotal	=	1,608,000	2116 +	1,608,000

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property, occuring before March 22, 2007, for current/prior years

** Fed.s.85	2117 +		or	2118 -	
** Fed.s.85.1	2119 +		or	2120 -	
** Fed.s.97	2121 +		or	2122 -	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	2123 +		or	2124 -	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	2125 +		or	2126 -	
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years	2127 +		or	2128 -	
Interest allowable under ss. 20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income				2150 -	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)				2155 -	

Subtotal (Additions)	=	2129 +	
Subtotal (Subtractions)	=	2130 -	
** Other adjustments		2131 ±	
Subtotal ± 2100 - 2110 + 2116 + 2129 - 2130 ± 2131		2132 =	4,231,606
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss		2133 ±	
Adjusted net income (loss) (if loss, transfer to **2202** in ***Part 2: Continuity of CMT Losses Carried Forward.***)		2134 =	4,231,606
Deduct: * CMT losses: pre-1994 Loss	From 2210 +		
* CMT losses: other eligible losses	2211 +		
	=	2135 -	

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this tax return*.

CMT Base	2136 =	4,231,606

Transfer to CMT Base on page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)

Part 2: Continuity of CMT Losses Carried Forward

CMT loss continuity by year

Year of origin	Beginning balance	Transfers on amalgamation	Transfers on wind-up	Adjustments	Current year loss	Applied	Ending balance
							Expired
2001/12/31							
2002/12/31							
2003/12/31							
2004/12/31							
2005/12/31							
2006/12/31							
2007/04/30							
2007/12/31							
2008/12/31							
Totals							

Balance at Beginning of year Notes (1), (2) **2201** +

Add: Current year's losses **2202** +

Losses from predecessor corporations on amalgamation that occurred before March 22, 2007 **Note (3)** **2203** +

Losses from predecessor corporations on wind-up completed before March 22, 2007 **Note (3)** **2204** +

Amalgamation (1) **2205** ☐ Yes Wind-up (1) **2206** ☐ Yes

Subtotal = ▶ **2207** +

Adjustments (attach schedule) **2208** ±

CMT losses available 2201 + **2207** ± **2208** **2209** =

Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income **2210** +

Other eligible losses utilized during the year to reduce adjusted net income **Note (4)** **2211** +

Losses expired during the year **2212** +

Subtotal = ▶ **2213** -

Balances at End of Year Note (5) 2209 - **2213** **2214** =

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation that occurred before March 22, 2007, to which fed.s.87 applies and/or a wind-up completed before March 22, 2007, to which fed.s.88(1) applies (see s.57.5(8) and s.57.5(9)). The continuation of CMT losses no longer applies for amalgamations and wind-ups that occur after March 21, 2007.

(4) CMT losses must be used to the extent of the lesser of the adjusted net income **2134** and CMT losses available **2209**.

(5) Amount in **2214** must equal sum of **2270** + **2290**.

(6) Include the lesser of the total investment losses of a predecessor corporation from an investment in another predecessor corporation that is controlled by the first predecessor corporation, and the total unused CMT losses of the other predecessor corporation.

(7) Include the lesser of the total investment losses of the parent corporation from its investment in the subsidiary corporation, and the total unused CMT losses of the subsidiary corporation.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

Year of Origin (oldest year first)	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	**2260**	**2280**
2241 2001/12/31	**2261**	**2281**
2242 2002/12/31	**2262**	**2282**
2243 2003/12/31	**2263**	**2283**
2244 2004/12/31	**2264**	**2284**
2245 2005/12/31	**2265**	**2285**
2246 2006/12/31	**2266**	**2286**
2247 2007/04/30	**2267**	**2287**
2248 2007/12/31	**2268**	**2288**
2249 2008/12/31	**2269**	**2289**
Totals	**2270**	**2290**

The sum of amounts 2270 + 2290 must equal amount in 2214.

Corporate Minimum Tax (CMT)

Part 4: Continuity of CMT Credit Carryovers

CMT credit continuity by year

Year of origin	Beginning balance	Transfers on amalgamation or wind-up	Adjustments	Current year credit	Applied	Expired	Ending balance
2002/12/31							
2003/12/31							
2004/12/31							
2005/12/31							
2006/12/31							
2007/04/30							
2007/12/31							
2008/12/31							
Totals							

Balance at Beginning of year Note (1) 2301 +

Add: Current year's CMT Credit (**280** on page 8 of the CT23 or **347** on page 6 of the CT8. If negative, enter NIL) From **280 or 347** +

Gross Special Additional Tax **Note (2) 312** on page 5 of CT8.
(Life Insurance corporations only. Others enter NIL.) From **312** +

Subtract Income Tax
(**190** on page 6 of the CT23 or page 4 of the CT8) From **190** -

Subtotal (If negative, enter NIL) = **2305** -

Current year's CMT credit (If negative, enter NIL) **280** or **347** – **2305** = **2310** +

CMT Credit Carryovers from predecessor corporations **Note (3)** **2325** +

Amalgamation (1) **2315** ☐ Yes Wind-up (1) **2320** ☐ Yes

Subtotal 2301 + **2310** + **2325** **2330** +

Adjustments *(Attach schedule)* **2332** ±

CMT Credit Carryover available 2330 ± **2332** **2333** =

Transfer to Page 8 of the CT23
or page 6 of the CT8

Subtract: CMT credit utilized during the year to reduce income tax
(**310** on page 8 of the CT23 or **351** on page 6 of the CT8.) + From **310 or 351**
CMT Credit expired during the year **2334** +

Subtotal = **2335** -

Balance at End of Year Note (4) 2333 - **2335** **2336** =

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))
(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).
(3) Include and indicate whether CMT credits are a result of an amalgamation that occurred before March 22, 2007 to which fed.s.87 applies and/or a wind-up completed before March 22, 2007, to which fed.s.88(1) applies. (see s.43.1(4))
(4) Amount in **2336** must equal the sum of **2370** + **2390**.

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

Year of Origin (oldest year first)	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	**2360**	**2380**
2341	**2361**	**2381**
2342 2002/12/31	**2362**	**2382**
2343 2003/12/31	**2363**	**2383**
2344 2004/12/31	**2364**	**2384**
2345 2005/12/31	**2365**	**2385**
2346 2006/12/31	**2366**	**2386**
2347 2007/04/30	**2367**	**2387**
2348 2007/12/31	**2368**	**2388**
2349 2008/12/31	**2369**	**2389**
Totals	**2370**	**2390**

The sum of amounts 2370 + 2390 must equal amount in 2336.

Ontario

Ministry of Finance
Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007

CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act - Ministry of Finance (MOF)
Corporations Information Act - Ministry of Government Services (MGS)

This form is a combination of the Ministry of Revenue (MOR) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return.** Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☒ Yes ☐ No

Ministry Use

Corporation's Legal Name *(including punctuation)*
Newmarket - Tay Power Distribution Ltd

Ontario Corporations Tax Account No. (MOF)
1800410

This Return covers the Taxation Year
Start 2008/01/01
End 2008/12/31

Mailing address
590 Steven Court

City	Province	Country	Postal code
Newmarket	ON	CA	L3Y 6Z2

Has the mailing address changed since last filed CT23 Return? ☐ Yes | Date of Change | year month day

Date of Incorporation or Amalgamation
2007/04/30

Registered/Head Office Address
590 Steven Court

City	Province	Country	Postal code
Newmarket	ON		L3Y 6Z2

Ontario Corporation No. (MGS) 1800410

Location of Books and Records
590 Steven Court

City	Province	Country	Postal code
Newmarket	ON		L3Y 6Z2

Canada Revenue Agency Business No.
869077925RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
Iain Clinton, CA	(905) 953-8548	( ) -

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario (*Extra-Provincial Corporations only*) (MGS)
590 Steven Court

City	Province	Country	Postal code
Newmarket	ON	CA	L3Y 6Z2

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced
Ceased
☒ *Not Applicable*

Former Corporation Name (*Extra-Provincial Corporations only*) ☒ *Not Applicable* (MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). No. of Schedule(s): 0

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check 1 this box. Schedule(s) A and K are not required (MGS). ☒ **No Change**

Preferred Language / *Langue de préférence*
☒ English *anglais* ☐ French *français*

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person
Iain Clinton

Title: D ☐ Director O ☒ Officer P ☐ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Taxation Year End

Exempt From Filing (EFF) Corporations Tax Return Declaration

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)

This EFF Declaration must be filed for each taxation year that the corporation is exempt from filing and must be filed within 6 months after the corporation's taxation year end.

Criteria for exempt from filing status:

a) has filed a federal Income Tax Return (T2) with Canada Revenue Agency for the taxation year;
b) had no Ontario taxable income for the taxation year (subject to the provisions in Note 2 below);
c) had no Ontario Corporations Tax payable for the taxation year;
d) was a Canadian-controlled private corporation throughout the taxation year (i.e. generally a private corporation with 50% or more shares owned by Canadian residents as defined by the *Income Tax Act* (Canada));
e) has provided its Canada Revenue Agency business number to the Ministry of Revenue; and
f) is **not** subject to the Corporate Minimum Tax (i.e. alone or as part of an associated group whose total assets exceed $5 million or whose total revenue exceeds $10 million for the taxation year).

Note 1: Filing of this declaration and the Annual Return does not constitute the filing of a Corporations Tax Return under section 75 of the *Corporations Tax Act*.

Note 2: The following loss situations will require otherwise EFF corporations to file a CT23 tax return complete with all related schedules and financial statements:

- If a corporation has a loss in the current taxation year that is to be carried back and applied to a previous taxation year(s), regardless of whether the loss is the same as for federal purposes or not, a CT23 tax return is required for the current taxation year. The corporation must also provide information indicating that the loss is to be carried back and specify the year and the amount of loss to be carried back to each taxation year.
- If a corporation has a prior year loss, that is not the same for both federal and Ontario purposes and the corporation is applying a loss carryforward from the prior year to the current year, a CT23 tax return is required for the current taxation year, and if not previously filed, a CT23 tax return for the prior taxation year in which the loss was incurred is also required. Although a tax return for the loss year is not required where the loss is not being applied, the ministry will accept the filing of a tax return for a loss year at the time the loss is incurred.
- If a corporation has a prior year loss, that is the same for both federal and Ontario purposes, but in the current taxation year the corporation is applying a different amount of loss for Ontario than the loss amount being applied for federal income tax purposes, the corporation is required to file a CT23 tax return for the current taxation year only.

The following 3 items MUST be completed for EFF declarations only. In cases where the Annual Return, which includes page 1, is **also** being filed, completion of these fields is **not** required.

1. Corporation's Mailing Address

City Province Country Postal code

2. Ontario Corporation No. (MGS)

3. Canada Revenue Agency Business No. RC

I, ______________________________ declare that:

The above corporation meets **all** of the exempt from filing criteria (a) through (f) above for the taxation year and therefore qualifies under the *Corporations Tax Act* as exempt from filing an Ontario Corporations Tax Return.

Signature	Title/Relationship to Corporation	Telephone number ( ) -	Date

Please note that making a false statement to avoid compliance with the *Corporations Tax Act* is an offence which can result in a penalty and/or fine.

If you check "Yes" to ALL of the following criteria, you are eligible to file the CT23 Short-Form Corporations Tax Return. To obtain a copy, contact the Ministry Information Centre at the numbers listed on page 2 of the Guide.

Yes	No		
X		(a)	The corporation is a Canadian-controlled private corporation (CCPC) throughout the taxation year. Indicate Share Capital with full voting rights owned by Canadian Residents (nearest whole percentage) 100 %
	X	(b)	The corporation's taxable income for the taxation year is $200,000 or less. For a taxation year with less than 51 weeks, taxable income must be grossed-up. (*Refer to Guide.)*
	X	(c)	The corporation is **not** a member of a partnership/joint venture or a member of an associated group of corporations during the taxation year.
	X	(d)	The corporation's taxation year ends on or after January 1, 2001, and its gross revenue and total assets are each $1,500,000 or less and the corporation is not a financial institution; or The corporation's taxation year commences after September 30, 2001, and its gross revenue and total assets are each $3,000,000 or less and the corporation is not a financial institution.
	X	(e)	The corporation is **not** claiming a tax credit other than the Incentive Deduction for Small Business Corporations (IDSBC), Co-operative Education Tax Credit (CETC), Graduate Transitions Tax Credit (GTTC) or Apprenticeship Training Tax Credit (ATTC).
X		(f)	The corporation's Ontario allocation factor is 100%.

Note: Family Farm or Fishing corporations that have a taxation year ending on or after January 1, 2000 and are **not** subject to the Corporate Minimum Tax, may also use the **CT23 Short-Form Corporations Tax Return** if the corporation checks "Yes" to a), b), c), e) and f) above.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (1 **) box(es) and complete required information.**

Type of Corporation

1
- 1 [X] Canadian-controlled private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
- 2 [ ] Other Private
- 3 [ ] Public
- 4 [ ] Non-share Capital
- 5 [ ] Other (*specify*)

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2
- 1 [ ] Family Farm corporation s.1(2)
- 2 [ ] Family Fishing corporation s.1(2)
- 3 [ ] Mortgage Investment corporation s.47
- 4 [ ] Credit Union s.51
- 5 [ ] Bank Mortgage subsidiary s.61(4)
- 6 [ ] Bank s.1(2)
- 7 [ ] Loan and Trust corporation s.61(4)
- 8 [ ] Non-resident corporation s.2(2)(a) or (b)
- 9 [ ] Non-resident corporation s.2(2)(c)
- 10 [ ] Mutual Fund corporation s.48
- 11 [ ] Non-resident owned investment corporation s.49
- 12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
- 14 [ ] Bare Trustee corporation
- 15 [ ] Branch of Non-resident s.63(1)
- 16 [ ] Financial institution prescribed by Regulation only
- 17 [ ] Investment Dealer
- 18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
- 19 [X] Hydro successor, municipal electrical utility or subsidiary of either
- 20 [ ] Producer and seller of steam for uses other than for the generation of electricity
- 21 [ ] Insurance Exchange s.74.4
- 22 [ ] Farm Feeder Finance Co-operative corporation
- 23 [ ] Professional corporation (incorporated professionals only)

- [ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)
- [ ] Amended Return
- [ ] Taxation year end change - Canada Revenue Agency approval required
- [ ] Final taxation year up to dissolution (*Note: for discontinued businesses, see guide*.)
- [ ] Final taxation year before amalgamation
- [ ] The corporation has a floating fiscal year end
- [ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario
- [ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year
  If checked, date control was acquired ______________
- [ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)
- [ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)
- [ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
[ ]	[X]	the Carry-back of a Loss?
[ ]	[X]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a Member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use Head Office no.) ______________

Ontario Employer Health Tax Account no. (Use Head Office no.) ______________

Specify major business activity
Electricity Distribution

Income Tax

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	From **690**	±	4,480,408
Subtract: Charitable donations	**1**	-	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	**2**	-	
Subtract: Taxable dividends deductible, per federal Schedule 3	**3**	-	
Subtract: Ontario political contributions *(Attach schedule* 2A) (Int.B. 3002R)	**4**	-	
Subtract: Federal Part VI.1 tax ______ X 3	**5**	-	
Subtract: Prior years' losses applied - Non-capital losses	From **704**	-	
Net capital losses (page 16) From **715** ______ X inclusion rate 50.000000 % =	**714**	-	
Farm losses	From **724**	-	
Restricted farm losses	From **734**	-	
Limited partnership losses	From **754**	-	
Taxable income (Non-capital loss)	**10**	=	4,480,408
Addition to taxable income for unused foreign tax deduction for federal purposes	**11**	+	
Adjusted taxable income 10 + **11** (if **10** is negative, enter **11**)	**20**	=	4,480,408

Taxable Income — **Number of days in Taxation Year**

From **10** (or **20**)	4,480,408	X **30** 100.0000 % (Ontario Allocation)	X 12.5%	X **33** (Days after Dec. 31, 2002 and before Jan. 1, 2004)	÷ **73** 366 (Total Days)	=	**29** +	
From **10** (or **20**)	4,480,408	X **30** 100.0000 % (Ontario Allocation)	X 14.0%	X **34** 366 (Days after Dec. 31, 2003)	÷ **73** 366 (Total Days)	=	**32** +	627,257

Income Tax Payable (before deduction of tax credits) **29** + **32** — **40** = 627,257

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (1) ☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))			**50**	4,480,408
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	**51** +	4,480,408		
Add: Losses of other years deducted for federal purposes (fed.s.111)	**52** +			
Subtract: Losses of other years deducted for Ontario purposes (s.34)	**53** -			
	=	4,480,408	▶ **54**	4,480,408
Federal Business limit (line 410 of the T2 return) for the year before the application of fed.s.125(5.1)	**55** +	400,000		

Ontario Business Limit Calculation

320,000 X **31** ______ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ ** 366 =+ **46** ______

400,000 X **34** 366 (Days after Dec. 31, 2003) ÷ ** 366 =+ **47** 500,000

Business limit for Ontario purposes **46** + **47** = **44** 500,000 X **48** 100.0000 % (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) = **45** 500,000

Income eligible for the IDSBC From **30** 100.0000 % (***Ontario Allocation) X **56** 500,000 (Least of **50**, **54** or **45**) **60** = 500,000

* ***Note***: *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note***: *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note***: *Ontario Allocation for IDSBC purposes may differ from* ***30*** *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

Calculation of IDSBC Rate	7.0% X **31**	Days after Dec. 31, 2002 and before Jan. 1, 2004:	÷ **73**	Total Days: 366	= **89** +	
	8.5% X **34**	Days after Dec. 31, 2003: 366	÷ **73**	Total Days: 366	= **90** +	8.5000
IDSBC Rate for Taxation Year **89** + **90**					**78** =	8.5000
Claim	From **60**	500,000	X From **78**	8.5000 %	**70** =	42,500

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount in **114** below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

*** Taxable Income of the corporation** From **10** (or **20** if applicable) **80** + 4,480,408

If you are a member of an associated group (*1*) **81** ☒ (Yes)

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
As per attached Schedule			+ **82**	
			+ **83**	
			+ **84**	

Aggregate Taxable Income **80 + 82 + 83 + 84** , etc. **85** = 4,480,408

Number of days in Taxation Year

320,000 X **31**	Days after Dec. 31, 2002 and before Jan. 1, 2004:	÷ **73**	Total Days: 366	= **115** +	
400,000 X **34**	Days after Dec. 31, 2003: 366	÷ **73**	Total Days: 366	= **116** +	500,000
			115 + **116**	=	500,000 ▶ **114** - 500,000

(If negative, enter nil) **86** = 3,980,408

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax	4.667% X **38**	Days after Dec. 31, 2002: 366	÷ **73**	Total Days: 366	= **97** + 4.2500
From **86** 3,980,408	X From **97** 4.2500 % =				**87** = 169,167
From **87** 169,167	X From **60** 500,000	÷ From **114** 500,000			**88** = 169,167

Surtax Lesser of **70** or **88** **100** = 42,500

*** *Note: Short Taxation Years*** - Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Income Tax *continued from Page 5*

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* 110

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits		**120** +	
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From	**56** -	500,000

Add: Adjustment for Surtax on Canadian-controlled private corporations
From **100** 42,500 ÷ From **30** 100.0000 % ÷ From **78** 8.5000 % = **121** 500,000
*Ontario Allocation

Lesser of **56** or **121**		**122** +	500,000
120 - **56** + **122**		**130** =	
Taxable income	From	**10** +	4,480,408
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From	**56** -	500,000
Add: Adjustments for Surtax on Canadian-controlled private corporations	From	**122** +	500,000
Subtract: Taxable income **10** X Allocation % to jurisdictions outside Canada		**140** -	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses		**141** -	
10 - **56** + **122** - **140** - **141**		**142** =	4,480,408

Claim — **Number of Days in Taxation Year**

143 ____ (Lesser of **130** or **142**) X From **30** 100.0000 (*Ontario Allocation) % X 1.5% X **33** ____ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ **73** 366 (Total Days) = **154** +

143 ____ (Lesser of **130** or **142**) X From **30** 100.0000 (*Ontario Allocation) % X 2.0% X **34** 366 (Days after Dec. 31, 2003) ÷ **73** 366 (Total Days) = **156** +

M&P claim for taxation year **154** + **156** — **160** =

***Note**: *Ontario Allocation for M&P Credit purposes may differ from **30** if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations — 161 =

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity — 162 =

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* **170**

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit **175** ____ Credit Claimed **180** ____

Subtotal of Income Tax **40** - **70** + **100** - **110** - **160** - **161** - **162** - **170** - **180** — 190 = 627,257

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit from **5620** OITC Claim Form *(Attach original Claim Form)* **191** +

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit from **5798** CT23 Schedule 113 (*Attach Schedule 113*) **192** +

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. **204** Name of Production
Eligible Credit from **5850** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* **193** +

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From **6596** **194**
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005.
Eligible Credit from **6598** CT23 Schedule 115 *(Attach Schedule 115)* **195** +

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit from **6900** OBPTC Claim Form
*(Attach **both** the original Claim Form and the Certificate of Eligibility)* **196** +

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit from **6700** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) (*Attach the original Certificate of Eligibility*) **197** +

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit from **7100** OBRITC Claim Form *(Attach original Claim Form)* **198** +

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit from **7300** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* **199** +

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit from **7400** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* **200** +

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit from **7500** OSRTC Claim Form
*(Attach **both** the original Claim Form and the Certificate of Eligibility)* **201** +

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From **5896** **202**
Applies to employment of eligible apprentices.
Eligible Credit from **5898** CT23 Schedule 114 (*Attach Schedule 114*) **203** +

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 **220** =

Specified Tax Credits ***Applied to reduce Income Tax*** **225** =

Income Tax **190 - 225 OR Enter NIL if reporting Non-Capital Loss** (*amount cannot be negative*) **230** = 627,257

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8**. If CMT is not applicable, transfer amount in **230** to Income Tax in **Summary** section on **Page 17**.

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8**.

Corporate Minimum Tax (CMT)

Total Assets of the corporation	**240** +	75,464,012		
Total Revenue of the corporation			**241** +	16,237,000

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

***If you are a member of an associated group (** 1) **242** ☒ (Yes)

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
As per attached Schedule			+ **243**	+ **244**
			+ **245**	+ **246**
			+ **247**	+ **248**

Aggregate Total Assets **240 + 243 + 245 + 247** , etc.	**249** =	75,464,012		
Aggregate Total Revenue **241 + 244 + 246 + 248**, etc.			**250** =	16,237,000

Determination of Applicability

Applies if ***either*** Total Assets **249** exceeds $5,000,000 ***or*** Total Revenue **250** exceeds $10,000,000.

Short Taxation Years - Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation - The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101.**

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - CMT Base From Schedule 101 **2136** 4,231,606 (If negative, enter zero) X From **30** 100.0000 (Ontario Allocation) % X 4%		**276** =	169,264
Subtract: Foreign Tax Credit for CMT purposes *(Attach schedule)*		**277** -	
Subtract: Income Tax	From	**190** -	627,257
Net CMT Payable (if negative, enter Nil on page 17.)		**280** =	

If **280** is less than zero and you do not have a CMT credit carryover, transfer **230** from **Page 7** to **Income Tax Summary, on Page 17**.

If **280** is less than zero and you have a CMT credit carryover, complete A & B below.

If **280** is greater than or equal to zero, transfer **230** to **Page 17** and transfer **280** to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From **2333**

Application of CMT Credit Carryovers

A.	Income Tax (before deduction of specified credits)		From	**190** +	627,257
	Gross CMT Payable	From **276** + 169,264			
	Subtract: Foreign Tax Credit for CMT purposes	From **277** -			
	If **276** - **277** is negative, enter NIL in **290**	= 169,264		**290** -	169,264
	Income Tax eligible for CMT Credit			**300** =	457,993
B.	Income Tax (after deduction of specified credits)		From	**230** +	627,257
	Subtract: CMT credit used to reduce income taxes			**310** -	
	Income Tax			**320** =	627,257

Transfer to Page 17

***If A & B apply,* 310 *cannot exceed the lesser of* 230, 300 *and your CMT credit carryover available* 2333**.

If only B applies,* 310 *cannot exceed the lesser of* 230 *and your CMT credit carryover available 2333.

Capital Tax *(Refer to Guide and Int.B. 3011R)*

*If your corporation is a Financial Institution (s.58(2)), complete lines **480** and **430** on page 10 then proceed to page 13.*

*If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in **480** and **430** are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in **550** on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s. 2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	**350**	+	27,140,206
Retained earnings (if deficit, deduct) (Int.B. 3012R)	**351**	±	3,530,389
Capital and other surpluses, excluding appraisal surplus (Int.B. 3012R)	**352**	+	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	**353**	+	29,836,000
Bank loans (Int.B. 3013R)	**354**	+	
Bankers acceptances (Int.B. 3013R)	**355**	+	
Bonds and debentures payable (Int.B. 3013R)	**356**	+	
Mortgages payable (Int.B. 3013R)	**357**	+	
Lien notes payable (Int.B. 3013R)	**358**	+	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	**359**	+	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	**360**	+	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	**361**	+	1,138,882
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	**362**	+	
Subtotal	**370**	=	61,645,477
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	**371**	-	(7,058,924)
Deductible R&D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	**372**	-	
Total Paid-up Capital	**380**	=	68,704,401
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	**381**	-	
Electrical Generating Corporations Only - All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	**382**	-	
Net Paid-up Capital	**390**	=	68,704,401

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	**402**	+	837,106
Mortgages due from other corporations	**403**	+	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	**404**	+	
Loans and advances to unrelated corporations	**405**	+	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	**406**	+	160,417
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	**407**	+	
Total Eligible Investments	**410**	=	997,523

continued on Page 10

Capital Tax *continued from Page 9*

Total Assets (Int.B. 3015R)

Total Assets per balance sheet	**420** +	75,464,012
Mortgages or other liabilities deducted from assets	**421** +	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	**422** +	
Subtract: Investment in partnership(s)/joint venture(s)	**423** -	
Total Assets as adjusted	**430** =	75,464,012
Amounts in **360** and **361** (if deducted from assets)	**440** +	
Subtract: Amounts in **371**, **372** and **381**	**441** -	(7,058,924)
Subtract: Appraisal surplus if booked	**442** -	
Add or Subtract: Other adjustments (specify on an attached schedule)	**443** ±	
Total Assets	**450** =	82,522,936

Investment Allowance (**410** ÷ **450**) X **390**	**Not to exceed 410**	**460** =	830,487
Taxable Capital **390** - **460**		**470** =	67,873,914

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)

Gross Revenue of the corporation	16,237,000		
Corporation's Share of partnership(s)/joint venture(s) Gross Revenue *(Attach schedule)*			
Aggregate of Gross Revenue	16,237,000	**480**	16,237,000
Total Assets (as adjusted)	From	**430**	75,464,012

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004. Financial Institutions use calculations on page 13.*

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in **550** on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD) — **Number of Days in Taxation Year**

				Total Days		
7,500,000	X	**36** (Days after Dec. 31, 2004 and before Jan. 1, 2006)	÷	**73** 366	= **501** +	
10,000,000	X	**37** (Days after Dec. 31, 2005 and before Jan. 1, 2007)	÷	**73** 366	= **502** +	
12,500,000	X	**38** (Days after Dec. 31, 2006 and before Jan. 1, 2008)	÷	**73** 366	= **504** +	
15,000,000	X	**39** 366 (Days after Dec. 31, 2007)	÷	**73** 366	= **505** +	15,000,000
Taxable Capital Deduction (TCD)		**501 + 502 + 504 + 505**			**503** =	15,000,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate — **Number of Days in Taxation Year**

				Total Days		
0.3 %	X	**556** (Days before Jan. 1, 2007)	÷	**73** 366	= **511**	%
0.225 %	X	**557** 366 (Days after Dec. 31, 2006 and before Jan. 1, 2009)	÷	**73** 366	= **512**	0.2250 %
Capital Tax Rate		**511** + **512**			= **516**	0.2250 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If **430** and **480** on page 10 are both $3,000,000 or less, enter NIL in **550** on page 12 and complete the return from that point.

C2. If Taxable Capital in **470** is **equal to or less than the TCD** in **503**, enter NIL in **550** on page 12 and complete the return from that point.

C3. If Taxable Capital in **470 exceeds the TCD** in **503**, complete the following calculation and transfer the amount from **523** to **543** on page 12, and complete the return from that point.

+ From **470** ________
- From **503** ________
= **471** ________ x From **30** 100.0000 % (Ontario Allocation) x From **516** 0.2250 % (Capital Tax Rate) x **555** 366 (Days in taxation year) / 365 (366 if leap year) *If floating taxation year, refer to Guide.* = **523** + ________ *Transfer to **543** on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either **509** or **524** and complete this section before you can calculate your Capital Tax calculation under either Section E or Section F.

D1. ☐ **509** (1 if applicable) All corporations that you are associated with do **not** have a permanent establishment in Canada.
If Taxable Capital **470** on page 10 is equal to or less than the TCD **503** on page 10, enter NIL in **550** on page 12 and complete the return from that point.

If Taxable Capital **470** on page 10 exceeds the TCD **503** on page 10, proceed to **Section E**, enter the TCD amount in **542** in Section E, and complete Section E and the return from that point.

D2. ☒ **524** (1 if applicable) One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

D2. Calculation Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital from **470** on page 10 — From **470** + 67,873,914

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
As per attached Schedule			+ **531**	
			+ **532**	
			+ **533**	

Aggregate Taxable Capital **470 + 531 + 532 + 533**, etc. — **540** = 67,873,914

If **540** above is equal to or less than the TCD **503** on page 10, the corporation's Capital Tax for the taxation year, is NIL. Enter NIL in **523** in section E below, as applicable.
If **540** above is greater than the TCD **503** on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From **470** 67,873,914 ÷ From **540** 67,873,914 X From **503** 15,000,000 **541** = 15,000,000

*Transfer to **542** in Section E below*

Ss.69(2.1) Election Filed

☐ **591** (1 if applicable) — **Election filed.** *Attach a copy of Schedule 591 with this CT23 Return*. Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital **540** above, exceeds the TCD **503** on page 10.

Complete the following calculation and transfer the amount from **523** to **543**, and complete the return from that point.

+ From
470 67,873,914
\- **542** 15,000,000
= **471** 52,873,914 x From **30** 100.0000 % x From **516** 0.2250 % x **555** 366 = **523** + 118,966

Ontario Allocation — Capital Tax Rate — Days in taxation year *365 (366 if leap year) — **Total Capital Tax for the taxation year**

*Transfer to **543** and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+From
470 ______ X From **30** 100.0000 % x From **516** 0.2250 % = **561** +

Ontario Allocation — Capital Tax Rate

\- Capital tax deduction from **995** relating to **your corporation's** Capital Tax deduction, on Schedule 591 — From **995** -
562 =

Capital Tax **562** ______ X Days in taxation year **555** 366 = **563** + — **Total Capital tax for the taxation year**

*365 (366 if leap year)

*Transfer to **543** and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits	**543** =	118,966
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)*	**546** -	
Capital Tax 543 - 546 *(amount cannot be negative)*	**550** =	118,966

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions Only

For taxation years commencing **after May 4, 1999** enter NIL in **550** on page 12, and complete the return from that point.

1.2 Other than Credit Unions

*(Retain details of calculations for amounts in boxes **565** and **570**. Do not submit with this tax return.)*

565 ____ Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1	x **567** 0.4500 % Capital Tax Rate(1) *(Refer to Guide)*	x From **30** ____ % Ontario Allocation	x **555** ____ Days in taxation year *365 (366 if leap year)	= **569** +	
570 ____ Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount	x **571** ____ % Capital Tax Rate(2) *(Refer to Guide)*	x From **30** ____ % Ontario Allocation	x **555** ____ Days in taxation year *365 (366 if leap year)	= **574** +	

Capital Tax for Financial Institutions - other than Credit Unions (before Section 2) 569 + 574 **575** =

** If floating taxation year, refer to Guide*.

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments **585** -

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (1) ☐ Yes

Capital Tax - Financial Institutions 575 - 585 **586** =

*Transfer to **543** on Page 12*

Premium Tax (s.74.2 & 74.3) (*Refer to Guide*)

(1) Uninsured Benefits Arrangements **587** ____ x 2% **588** =
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in **588** and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in **588**.)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* **589** -

Premium Tax 588 - 589 **590** =

Transfer to Page 17

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1			**600** ±	4,480,408
				Transfer to Page 15

Add:

Federal capital cost allowance	**601** +	3,957,636		
Federal cumulative eligible capital deduction	**602** +	110,447		
Ontario taxable capital gain	**603** +			
Federal non-allowable reserves. Balance beginning of year	**604** +	919,041		
Federal allowable reserves. Balance end of year	**605** +			
Ontario non-allowable reserves. Balance end of year	**606** +	1,138,882		
Ontario allowable reserves. Balance beginning of year	**607** +			
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	**608** +			
Federal resource allowance *(Refer to Guide)*	**609** +			
Federal depletion allowance	**610** +			
Federal foreign exploration and development expenses	**611** +			
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	**617** +			
Management fees, rents, royalties and similar payments to non-arms' length non-residents				

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004	Total Days		
612	X 5/12.5 X	**33**	÷ **73** 366	= **633** +	
		Days after Dec. 31, 2003	Total Days		
612	X 5/14.0 X	**34** 366	÷ **73** 366	= **634** +	

Total add-back amount for Management fees, etc. **633 + 634** =	**613** +			
Federal Scientific Research Expenses claimed in year from line **460** of fed. form T661 excluding any negative amount in **473** from Ont. CT23 Schedule 161	**615** +			
Add any negative amount in **473** from Ont. CT23 Schedule 161	**616** +			
Federal allowable business investment loss	**620** +			
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	**614** +			
Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614	=	6,126,006	**640**	6,126,006
				Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under **675**)	**650** +	3,957,636
Ontario cumulative eligible capital deduction	**651** +	110,447
Federal taxable capital gain	**652** +	
Ontario non-allowable reserves. Balance beginning of year	**653** +	919,041
Ontario allowable reserves. Balance end of year	**654** +	
Federal non-allowable reserves. Balance end of year	**655** +	1,138,882
Federal allowable reserves. Balance beginning of year	**656** +	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	**657** +	
Ontario depletion allowance	**658** +	
Ontario resource allowance *(Refer to Guide)*	**659** +	
Ontario current cost adjustment *(Attach schedule)*	**661** +	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	**675** +	
Subtotal of deductions for this page 650 to 659 + 661 + 675	**681**	6,126,006
		Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net income (loss) for federal income tax purposes, per federal Schedule 1	From **600** ±		4,480,408
Total of Additions on page 14	From **640** =		6,126,006
Sub Total of deductions on page 14	From **681** =	6,126,006	

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year **662** ____________

ONTTI Gross-up deduction calculation:
From **662** ____________ Gross-up of CCA x 100/ **30** From Ontario Allocation 100.0000 - From **662** ____________ **663** =

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: **665** ____________ x 30% x 100/ **30** From Ontario Allocation 100.0000 **666** =

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: **667** ____________ x 100% x 100/ **30** From Ontario Allocation 100.0000 **668** =

Number of Employees accommodated **669**

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: **670** ____________ x 30% x 100/ **30** From Ontario Allocation 100.0000 **671** =

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: **672** ____________ x 15% x 100/ **30** From Ontario Allocation 100.0000 **673** =

Ontario allowable business investment loss	**678** +			
Ontario Scientific Research Expenses claimed in year in 477 from Ont. CT23 Schedule 161	**679** +			
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	**677** +			
Total of other deductions allowed by Ontario *(Attach schedule)*	**664** +			
Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664	=	6,126,006	**680**	6,126,006

Net income (loss) for Ontario Purposes **600** + **640** - **680** **690** = 4,480,408

Transfer to Page 4

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	**700** (2)	**710** (2)	**720** (2)	**730**	**740**	**750**
Add: Current year's losses (7)	**701**	**711**	**721**	**731**	**741**	**751**
Losses from predecessor corporations (3)	**702**	**712**	**722**	**732**		**752**
Subtotal	**703**	**713**	**723**	**733**	**743**	**753**
Subtract: Utilized during the year to reduce taxable income	**704** (2)	**715** (2)(4)	**724** (2)	**734** (2)(4)	**744** (4)	**754** (4)
Expired during the year	**705**		**725**	**735**	**745**	
Carried back to prior years to reduce taxable income (5)	**706** (2) To Pg 17	**716** (2) To Pg 17	**726** (2) To Pg 17	**736** (2) To Pg 17	**746**	
Subtotal	**707**	**717**	**727**	**737**	**747**	**757**
Balance at End of Year	**709** (8)	**719**	**729**	**739**	**749**	**759**

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first)	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year	**817** (9)	**860** (9)		**850**	**870**
801 8th preceding taxation year 2001/12/31	**818** (9)	**861** (9)		**851**	**871**
802 7th preceding taxation year 2002/12/31	**819** (9)	**862** (9)		**852**	**872**
803 6th preceding taxation year 2003/12/31	**820**	**830**	**840**	**853**	**873**
804 5th preceding taxation year 2004/12/31	**821**	**831**	**841**	**854**	**874**
805 4th preceding taxation year 2005/12/31	**822**	**832**	**842**	**855**	**875**
806 3rd preceding taxation year 2006/12/31	**823**	**833**	**843**	**856**	**876**
807 2nd preceding taxation year 2007/04/30	**824**	**834**	**844**	**857**	**877**
808 1st preceding taxation year 2007/12/31	**825**	**835**	**845**	**858**	**878**
809 Current taxation year 2008/12/31	**826**	**836**	**846**	**859**	**879**
Total	**829**	**839**	**849**	**869**	**889**

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from **11** if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in **709** must equal total of **829** + **839**.

(9) Include non-capital losses incurred in taxation years ending after
March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance**.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Corporation's Tax Account No. (MOF)	Taxation Year Ending	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			**910**	**920**	**930**	**940**
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income.						
i) 3rd preceding	**901**	2006/12/31	**911**	**921**	**931**	**941**
ii) 2nd preceding	**902**	2007/04/30	**912**	**922**	**932**	**942**
iii) 1st preceding	**903**	2007/12/31	**913**	**923**	**933**	**943**
Total loss to be carried back			From **706**	From **716**	From **726**	From **736**
Balance of loss available for carry-forward			**919**	**929**	**939**	**949**

Summary

		Line		Amount
Income Tax	From **230** or	**320**	+	627,257
Corporate Minimum Tax	From	**280**	+	
Capital Tax	From	**550**	+	118,966
Premium Tax	From	**590**	+	
Total Tax Payable		**950**	=	746,223
Subtract:	Payments	**960**	-	
	Capital Gains Refund (s.48)	**965**	-	
	Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	**985**	-	
	Specified Tax Credits *(Refer to Guide)*	**955**	-	
Balance		**970**	=	746,223
If payment due	Enclosed *	**990**		
If overpayment: Refund *(Refer to Guide)*		**975**	=	
Apply to		**980**		

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name
Iain Clinton

Title
Chief Financial Officer

Full Residence Address
590 Steven Court

City
Newmarket

Province	Country	Postal Code
ON	CA	L3Y 6Z2

Signature	Date
	2010/05/26

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Ontario

Ministry of Finance

Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

ONTARIO CAPITAL COST ALLOWANCE

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Newmarket - Tay Power Distribution Ltd	1800410	2008/12/31

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year	3 Cost of acquisitions during the the year See note 1 below	4 Net adjustments	5 Proceeds of dispositions during the year	6 Ontario undepreciated capital cost (col 2 + 3 or col 2 - 4 - 5)	7 50% rule See note 2 below	8 Reduced undepreciated capital cost (col 6 - 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (col 8 x 9 or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (col 6 - 12)
1	35,404,395	635,006			36,039,401	317,503	35,721,898	4			1,428,876	34,610,525
3	6,775				6,775		6,775	5			339	6,436
8	2,571,557	65,142			2,636,699	32,571	2,604,128	20			520,826	2,115,873
10	1,379,079	729,426			2,108,505	364,713	1,743,792	30			523,138	1,585,367
17	55,339				55,339		55,339	8			4,427	50,912
2	6,815,689				6,815,689		6,815,689	6			408,941	6,406,748
47	9,151,745	4,833,799			13,985,544	2,416,900	11,568,644	8			925,492	13,060,052
45	19,464				19,464		19,464	45			8,759	10,705
12	40,131	66,934			107,065	33,467	73,598	100			73,598	33,467
13	182,139	37,455			219,594	18,728	200,866				31,474	188,120
50		115,512			115,512	57,756	57,756	55			31,766	83,746
								Totals			3,957,636	

Enter in box **650** on the CT23

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

Ministry of Revenue

Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Cumulative Eligible Capital Deduction
Schedule 10
For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Newmarket - Tay Power Distribution Ltd	(MOF) 1800410	2008/12/31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 - Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital - balance at beginning of taxation year *(if negative, enter zero)*					+ 1,577,819	A
Add: Cost of eligible capital property acquired during the taxation year	+	B				
Other adjustments	+	C				
B + C	=	x 3/4	=	D		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002		x 1/2	=-	E		
D minus E (*if negative, enter zero*)			=		+	F
Amount transferred on amalgamation or wind-up of subsidiary					+	G
Subtotal A + F + G					= 1,577,819	H
Deduct:						
Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	+	I				
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada)	+	J				
Other adjustments	+	K				
I + J + K	=	x 3/4			= -	L
Ontario cumulative eligible capital balance H minus L					= 1,577,819	M

*If **M** is negative, enter zero at line **Q** and proceed to **Part 2**, page 2.*

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business				N		
From **M**	1,577,819					
From **N** -						
Current year deduction M minus N	1,577,819	x 7%*	= + 110,447	O		
N + **O**			= 110,447	▶	- 110,447	P

***Note**: The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.*

*Enter amount in box **651** of the CT23*

Ontario cumulative eligible capital - closing balance M minus **P** *(if negative, enter zero)* = 1,467,372 Q

See page 2 - part 2

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Newmarket - Tay Power Distribution Ltd	(MOF) 1800410	2008/12/31

Part 2 - Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative

Amount from line M above *show as a positive amount; not negative.*						R
Total of cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988			+	1		
Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80 (7)			+	2		
Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988	+	3				
Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988	-	4				
Deduct line 4 from line 3 (*if negative, enter zero*)	=		+	5		
Total lines **1 + 2 + 5**			=	6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line **1**		7				
Amounts at **Line** Z from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 (*This will be **Line T** in earlier versions of this schedule.*)	+	8				
Total lines 7 + 8	=		-	9		
Deduct line **9** from line **6** *(if negative, enter zero)*			=	▶	-	S
R minus S *(if negative, enter zero)*					=	T
From Line **5** ______ x 1/2					= -	U
T minus U (*if negative, enter zero*)					=	V
From **V** ______ x 66.6667 %					=	W
Lesser of line **R** and **S**					= +	Z
Amount to be included in income W + Z						

Ontario

Ministry of Finance

Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Newmarket - Tay Power Distribution Ltd	(MOF) 1800410	2008/12/31

For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes

Part 1 - Capital gains reserves

Description of property	Ontario balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Ontario balance at the end of the year
Totals	A	B	C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 - Other reserves

Description	Ontario balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Ontario balance at the end of the year
Reserve for doubtful debts			
Reserve for undelivered goods and services not rendered			
Reserve for prepaid rent			
Reserve for December 31, 1995 income			
Reserve for refundable containers			
Reserve for unpaid amounts			
Other tax reserves			
Totals	D	E	F

The amount from **D** plus the amount from **E** should be entered in **607** of the CT23.

The amount from **F** should be entered in **654** of the CT23.

Part 3 - Continuity of non-deductible reserves

Reserve	Ontario opening balance and transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
Post employment benefits	742,354				840,000
Percentage AR allowance	176,687				298,882
Totals	919,041				1,138,882
	*Enter in box **653** of the CT23*				*Enter in box **606** of the CT23*

Ontario

Ministry of Finance

Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Newmarket - Tay Power Distribution Ltd	1800410	2008/12/31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Due to related parties	1,665,000
Long term Debt	23,943,000
Customer deposits	3,850,000
Current portion of deposits	378,000
Total	29,836,000

*Transfer to **353** on the CT23*

Ontario

Ministry of Finance
Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Paid-Up Capital: Other Reserves

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Newmarket - Tay Power Distribution Ltd	1800410	2008/12/31

Description of Reserves NOT ALLOWED as a Deduction for Income Tax	Balance Beginning of the Year	Add	Deduct	Transfer on Amalgamation or Wind-up of Subsidiary	Balance at the End of the Year
Employee Future Benefits	742,354	98,000	354		840,000
AR allowance (non-specific)	176,687	122,195			298,882
				Total	1,138,882

*Transfer to **361** on the CT23*

Ontario **Ministry of Finance**
Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Corporate Minimum Tax - Associated Corporation

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Newmarket - Tay Power Distribution Ltd	1800410	2008/12/31

Name of Associated Corporation (Canadian and Foreign)	Corporations Tax Number	Taxation Year End	Total Assets	Total Revenue
Newmarket Hydro Holdings Inc		2008/12/31		
Unipower Holdings Ltd		2008/12/31		
1443393 Ontario Inc		2008/12/31		
1443394 Ontario Inc		2008/12/31		
1443396 Ontario Inc		2008/12/31		
1443397 Ontario Inc		2008/12/31		
1443398 Ontario Inc		2008/12/31		
1402318 Ontario Inc		2008/12/31		
Tay Utility Contracting Inc				
Tay Hydro Inc				
Township of Tay				
		Totals		
			*Transfer to **249** of the CT23*	*Transfer to **250** of the CT23*

Ontario

Ministry of Finance

Corporations Tax
PO Box 642
33 King Street West
Oshawa ON L1H 8T1

CT23 - Certification Form Diskette Filing

Return I.D. #____________________ *(Ministry Use Only)*

Corporations Tax Account Number
1800410

Please check appropriate boxes if applicable:

☐ First year of filing	☐ Final taxation year up to Dissolution	☐ Change of Control fed.s.249(4)
☐ Amended return	☐ Final taxation year before Amalgamation	Date Control was acquired: ____________
☐ Taxation year end has changed (approval by CCRA required)	☐ Floating Fiscal year end	
☐ Exempt from filing	☒ Subject to CMT	

Date of incorporation
2007/04/30

Return for taxation year
Start 2008/01/01
End 2008/12/31

CCRA Business No.
869077925RC0001

Jurisdiction Incorporated
Ontario

Corporation's legal name and mailing address
Newmarket - Tay Power Distribution Ltd
Care of

Change of information? Yes ☐ No ☒

Address
590 Steven Court

City	Province	Country	Postal code
Newmarket	ON	CA	L3Y 6Z2

Transmitter Details

Transmitter number
Transmitter name
Name of person to contact
Telephone number ( ) -
Facsimile number ( ) -
Transmitter Address

Disk Reference Number

Aggregate of Total Revenue	**210**	16,237,000
Aggregate of Total Assets	**209**	75,464,012
Taxable Income (Non-capital Loss)	**10**	4,480,408
Total Tax Payable	**950**	746,223
Payments:	**990**	
Enclosed:		
Apply to: Year		
Apply Amount:		

975 Refund:	Yes ☐	No ☒
If Yes, Due to:		
Loss Carryback:	Yes ☐	No ☒
Overpayment:	Yes ☐	No ☒
Refundable tax credit	Yes ☐	No ☒

Certification

I am an authorized signing officer of the Corporation. I certify that this Return, including all schedules and statements filed with or as part of this Return, has been examined by me and is a true, correct and complete Return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the Corporations Tax Act. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name
Iain Clinton

Title
Chief Financial Officer

Full Residence address
590 Steven Court

City
Newmarket

Province	Country	Postal code
ON	CA	L3Y 6Z2

Signature

Phone Number	Date
(905) 953-8548	2010/05/26

ProFile Version 2006.7.0 Approval code 080G

Payment Advice

Corporations Tax Account Number	1800410
Date of Incorporation	2007/04/30
Corporation Name	
Newmarket - Tay Power Distribution Ltd	

Enter the amount of payment and indicate taxation year.

Taxation Year End	Payment amount
	$
2008/12/31	$
Total Payment	$

Submit your cheque (drawn on a Canadian financial institution) or money order in Canadian Funds, payable to: The Minister of Finance

Send to: Ontario Ministry of Finance
Corporations Tax
P.O. Box 642
33 King Street West
Oshawa ON L1H 8T1

Incomplete information will result in a delay processing an assessment.

ALLOWANCE FOR PILS

The calculations of the allowance for 2010 PILs in the amount of $1,154,089 are provided in the “Proposed PILs model” at Exhibit 4, Tab 8, Schedule 3, Attachment 1.

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1

August 30, 2009

Model Overview

Select a worksheet link

Tab	ShortName	Title	Instruction	Link
P		**PILS Calculationa**		P0 Administration
P0	Admin	Administration	Enter administrative information about the Application	P0 Administration
P1	UCC	Undepreciated Capital Costs (UCC)	Enter actual balances and projected asset additions & retirements	P1 Undepreciated Capital Costs (UCC)
P2	CEC	Cumulative Eligible Capital (CEC)	Enter actual balance, projected changes and deduction rates	P2 Cumulative Eligible Capital (CEC)
P3	Interest	Interest Expense	Enter deemed and projected actual interest amounts	P3 Interest Expense
P4	LCF	Loss Carry-Forward (LCF)	Enter details of historical losses available to offset projected taxable income	P4 Loss Carry-Forward (LCF)
P5	Reserves	Reserve Balances	Enter balance amounts and projected changes in tax and accounting reserves	P5 Reserve Balances
P6	TxblIncome	Taxable Income	Enter amounts required to calculate taxable income	P6 Taxable Income
P7	CapitalTax	Capital Taxes	Enter rate base amounts	P7 Capital Taxes
P8	TotalPILs	Total PILs Expense	Enter tax credit amounts	P8 Total PILs Expense
Y		**Reference Information**		Y1 Tax Rates and Exemptions
Y1	TaxRates	Tax Rates and Exemptions	Enter applicable rates and exemption amounts	Y1 Tax Rates and Exemptions
Y2	CCA	Capital Cost Allowances (CCA)	Enter asset classes and applicable rates for CCA deductions	Y2 Capital Cost Allowances (CCA)
Z		**Model Parameters**		Z1 Model Variables
Z1	ModelVariables	Model Variables		Z1 Model Variables
Z0	Disclaimer	Software Terms of Use		Z0 Software Terms of Use

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1
August 30, 2009

P0 Administration

Enter administrative information about the Application

Application Version		v0.1
Name of Applicant		Newmaket-Tay
License Number		ED-2007-0624
Test Year		2010
File Number(s)		EB-2009-0269
Date of Application		30-Aug-2009
Contact:		
	Name	Iain Clinton
	email	iclinton@nmhydro.ca
	phone	905-953-8548
Date of previous Test Year approval		12-Apr-2006

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1
August 30, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions & retirements

Class	Description	UCC Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Less: Disallowed FMV Increment
1	Distribution System - post 1987	34,610,525		
2	Distribution System - pre 1988	6,406,748		
8	General Office/Stores Equip	2,115,873		
10	Computer Hardware/ Vehicles	1,585,367		
10.1	Certain Automobiles			
12	Computer Software	33,467		
13.1	Leasehold Improvement # 1	188,121		
13.2	Leasehold Improvement # 2			
13.3	Leasehold Improvement # 3			
13.4	Leasehold Improvement # 4			
14	Franchise			
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	50,912		
43.1	Certain Energy-Efficient Electrical Generating Equipment			
45	Computers & Systems Software acq'd post Mar 22/04	10,705		
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			
47	Distribution System post Feb 22/05	13,060,052		
50	Computer Equipment Post March 18, 2007	83,746		
3	Building pre 1988	6,436		
	TOTAL	**58,151,952**		

[1] per Schedule 8 of 2008 corporate tax return

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-026

August 30, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2009 CCA
1	Distribution System - post 1987	222,377		34,832,902	111,189	34,721,713	4.0%	1,388,869
2	Distribution System - pre 1988			6,406,748		6,406,748	6.0%	384,405
8	General Office/Stores Equip	44,293		2,160,167	22,147	2,138,020	20.0%	427,604
10	Computer Hardware/ Vehicles	346,763		1,932,130	173,382	1,758,749	30.0%	527,625
10.1	Certain Automobiles						30.0%	
12	Computer Software	38,316		71,783	19,158	52,625	100.0%	52,625
13.1	Leasehold Improvement # 1	254,135		442,256	127,067	315,188		50,681
13.2	Leasehold Improvement # 2						4 years	
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise						6 years	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			50,912		50,912	8.0%	4,073
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04			10,705		10,705	45.0%	4,817
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	4,969,564		18,029,616	2,484,782	15,544,834	8.0%	1,243,587
50	Computer Equipment Post March 18, 2007	26,096		109,842	13,048	96,794	55.0%	53,237
3	Building pre 1988			6,436		6,436	5.0%	322
	TOTAL	**5,901,544**		**64,053,496**	**2,950,772**	**61,102,724**		**4,137,843**

[1] per Schedule 8 of 2008 corporate tax return

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-026

August 30, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	UCC 31 Dec/09
1	Distribution System - post 1987	33,444,033
2	Distribution System - pre 1988	6,022,343
8	General Office/Stores Equip	1,732,563
10	Computer Hardware/ Vehicles	1,404,506
10.1	Certain Automobiles	
12	Computer Software	19,158
13.1	Leasehold Improvement # 1	391,575
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	46,839
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	5,888
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	16,786,029
50	Computer Equipment Post March 18, 2007	56,605
3	Building pre 1988	6,114
	TOTAL	**59,915,653**

[1] per Schedule 8 of 2008 corporate tax return

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-026

August 30, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	2010 Projected Additions	2010 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2010 CCA
1	Distribution System - post 1987	1,429,792		34,873,825	714,896	34,158,929	4.0%	1,366,357
2	Distribution System - pre 1988			6,022,343		6,022,343	6.0%	361,341
8	General Office/Stores Equip	92,040		1,824,603	46,020	1,778,583	20.0%	355,717
10	Computer Hardware/ Vehicles	115,000		1,519,506	57,500	1,462,006	30.0%	438,602
10.1	Certain Automobiles						30.0%	
12	Computer Software	260,200		279,358	130,100	149,258	100.0%	149,258
13.1	Leasehold Improvement # 1	95,000		486,575	47,500	439,075		75,000
13.2	Leasehold Improvement # 2							
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise							
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			46,839		46,839	8.0%	3,747
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04			5,888		5,888	45.0%	2,649
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	8,346,475		25,132,504	4,173,238	20,959,267	8.0%	1,676,741
50	Computer Equipment Post March 18, 2007	45,100		101,705	22,550	79,155	55.0%	43,535
3	Building pre 1988			6,114		6,114	5.0%	306
	TOTAL	**10,383,607**		**70,299,260**	**5,191,804**	**65,107,456**		**4,473,253**

[1] *per Schedule 8 of 2008 corporate tax return*

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-026

August 30, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	UCC 31 Dec/10
1	Distribution System - post 1987	33,507,468
2	Distribution System - pre 1988	5,661,002
8	General Office/Stores Equip	1,468,886
10	Computer Hardware/ Vehicles	1,080,904
10.1	Certain Automobiles	
12	Computer Software	130,100
13.1	Leasehold Improvement # 1	411,575
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	43,092
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	3,238
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	23,455,763
50	Computer Equipment Post March 18, 2007	58,170
3	Building pre 1988	5,808
	TOTAL	**65,826,007**

[1] per Schedule 8 of 2008 corporate tax return

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1
August 30, 2009

P2 Cumulative Eligible Capital (CEC)

Enter actual balance, projected changes and deduction rates

	2009				2010			
CEC Opening Balance [1]				1,467,372				1,364,656
Eligible Capital Property (ECP) Acquisitions								
Other Adjustments								
Subtotal		x 3/4 =				x 3/4 =		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002		x 1/2 =				x 1/2 =		
Amount transferred on amalgamation or wind-up of subsidiary								
Subtotal before deductions				1,467,372				1,364,656
ECP Dispositions (net)								
Other Adjustments								
Subtotal		x 3/4 =				x 3/4 =		
Balance before tax deduction				1,467,372				1,364,656
Tax Deduction		*Rate:*	*7.0%*	102,716		*Rate:*	*7.0%*	95,526
CEC Ending Balance				1,364,656				1,269,130

[1] *2009 amount per ending balance on Schedule 10 of 2008 corporate rax return*

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1
August 30, 2009

P3 Interest Expense

Enter deemed and projected actual interest amounts

	2009	2010	
Deemed Interest Expense (A)			
3900-Interest Expense			
Add: Capitalized Interest (USA #6040)			*Enter credit to P&L as positive number*
Add: Capitalized Interest (USA #6042)			*Enter credit to P&L as positive number*
Less: non-debt interest expense (USA #6035)			
			Enter other adjustments for tax purposes
Total Interest Projected (B)			
Excess Interest Expense			*(B) less (A); if negative: zero*

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1

August 30, 2009

P4 Loss Carry-Forward (LCF)

Enter details of historical losses available to offset projected taxable income

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	2009	2010
Non-Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable income					
Ending Balance					
Net Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable capital gains					
Ending Balance					

[1] per Schedule 7-1 of 2008 corporate tax return

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1
August 30, 2009

P5 Reserve Balances

Enter balance amounts and projected changes in tax and accounting reserves

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	Changes (+ / -) in 2009	Balance 31 Dec/09	Changes (+ / -) in 2010	Balance 31 Dec/10
Capital Gains Reserves ss.40(1)							
Tax Reserves not deducted for book purposes:							
Reserve for doubtful accounts ss. 20(1)(l)							
Reserve for goods and services not delivered ss. 20(1)(m)							
Reserve for unpaid amounts ss. 20(1)(n)							
Debt & Share Issue Expenses ss. 20(1)(e)							
TOTAL							
Accounting Reserves not deducted for tax purposes:							
General Reserve for Inventory Obsolescence (non-specific)							
General reserve for bad debts					356,000		356,000
Accrued Employee Future Benefits:					938,000	43,000	981,000
- Medical and Life Insurance							
- Short & Long-term Disability							
- Accumulated Sick Leave							
- Termination Cost							
- Other Post-Employment Benefits							
Provision for Environmental Costs							
Restructuring Costs							
Accrued Contingent Litigation Costs							
Accrued Self-Insurance Costs							
Other Contingent Liabilities							
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)							
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)							
TOTAL					**1,294,000**	**43,000**	**1,337,000**

[1] *per Schedule 13 of 2008 corporate tax return*

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1

August 30, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]					5,225,161	1,067,513	3,684,789
Additions:							
Interest and penalties on taxes	103						
Amortization of tangible assets	104				4,249,838	4,525,693	4,525,693
Amortization of intangible assets	106						
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109						
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112						
Taxable Capital Gains	113						
Political Donations	114						
Deferred and prepaid expenses	116						
Scientific research expenditures deducted on financial statements	118						
Capitalized interest	119						
Non-deductible club dues and fees	120						
Non-deductible meals and entertainment expense	121				22,500	30,000	30,000
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125						
Reserves from financial statements- balance at end of year	126				1,294,000	1,337,000	1,337,000

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1
August 30, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved			2009 Projection	2010 @ existing rates	2010 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]					5,225,161	1,067,513	3,684,789
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						
Capital items expensed	206						
Debt issue expense	208						
Development expenses claimed in current year	212						
Financing fees deducted in books	216						
Gain on settlement of debt	220						
Non-deductible advertising	226						
Non-deductible interest	227						
Non-deductible legal and accounting fees	228						
Recapture of SR&ED expenditures	231						
Share issue expense	235						
Write down of capital property	236						
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Total Additions					**5,566,338**	**5,892,693**	**5,892,693**

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1

August 30, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved			2009 Projection	2010 @ existing rates	2010 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]					5,225,161	1,067,513	3,684,789
Deductions:							
Gain on disposal of assets per financial statements	401						
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403				4,137,843	4,473,253	4,473,253
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405				102,716	95,526	95,526
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413						
Reserves from financial statements - balance at beginning of year	414				1,138,882	1,294,000	1,294,000
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Total Deductions					**5,379,441**	**5,862,779**	**5,862,779**

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1
August 30, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved			2009 Projection	2010 @ existing rates	2010 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]					5,225,161	1,067,513	3,684,789
NET INCOME (LOSS) FOR TAX PURPOSES					**5,412,058**	**1,097,427**	**3,714,703**
Charitable donations from Schedule 2							
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)					**5,412,058**	**1,097,427**	**3,714,703**

[1] *2009 Projection = "Earnings before Tax' (sheet E1); 2010 @ existing rates = "Earnings before Tax' (sheet E2); 2010 @ new dist. rates = "Deemed Return On Equity' (sheet E3)*

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1

August 30, 2009

P7 Capital Taxes

Enter rate base amounts

Rates and exemptions from sheet Y1

	2009	2010	
OCT (Ontario Capital Tax):			
Taxable Capital	69,459,129	68,200,000	*'Calculated Value' from sheet E3*
Less: Exemption	15,000,000	15,000,000	
Deemed Taxable Capital	54,459,129	53,200,000	
Tax Rate	0.225%	0.075%	
OCT payable	**122,533**	**39,900**	
Federal LCT (Large Corporations Tax):			
Rate Base	69,459,129	68,200,000	
Less: Exemption	50,000,000	50,000,000	
Deemed Taxable Capital	19,459,129	18,200,000	
Tax Rate			
LCT payable			

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1

August 30, 2009

P8 Total PILs Expense

Enter tax credit amounts

	2009 Projection	2010 Projection [1]	2010 Test [1]	
Regulatory Taxable Income/(Loss)	5,412,058	1,097,427	3,714,703	*from sheet P6*
Combined Income Tax Rate	34.75%	35.31%	31.07%	*"t" (from sheet Y1)*
Total Income Taxes	1,890,932	387,542	1,154,089	
Investment & Miscellaneous Tax Credits				*Input amounts*
Income Tax Payable	**1,890,932**	**387,542**	**1,154,089**	*"i"*
Large Corporations Tax (LCT)				*from sheet P7*
Ontario Capital Tax (OCT)	122,533	39,900	39,900	*from sheet P7*
Grossed-up Income Tax			1,674,246	*= i / (1 - t)*
Grossed-up LCT				*= LCT / (1 - t)*
Total PILs Expense	**2,013,465**	**427,442**	**1,714,146**	***Enter these results on sheet E4***

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1

August 30, 2009

Y1 Tax Rates and Exemptions

Enter applicable rates and exemption amounts

2009 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$400,000	11.00%	5.50%	16.50%	
$400,000	$500,000	19.00%	5.50%	24.50%	
$500,000	$1,500,000	19.00%	14.50%	33.50%	4.25%
$1,500,000		19.00%	15.75%	34.75%	

2009 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$15,000,000
Capital Tax Rate		0.225%
Surtax Rate		

2010 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$400,000	11.00%	5.50%	16.50%	
$400,000	$500,000	19.00%	5.50%	24.50%	
$500,000	$1,500,000	19.00%	14.00%	33.00%	4.25%
$1,500,000		19.00%	12.07%	31.07%	

2010 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$15,000,000
Capital Tax Rate		0.075%
Surtax Rate		

Newmaket-Tay (ED-2007-0624)

PILs Calculations for 2010 EDR Application (EB-2009-0269) version: v0.1
August 30, 2009

Y2 Capital Cost Allowances (CCA)

Enter asset classes and applicable rates for CCA deductions

Class	Description	Rate	Years	½ Year Rule
1	Distribution System - post 1987	4.0%		YES
2	Distribution System - pre 1988	6.0%		YES
8	General Office/Stores Equip	20.0%		YES
10	Computer Hardware/ Vehicles	30.0%		YES
10.1	Certain Automobiles	30.0%		YES
12	Computer Software	100.0%		YES
13.1	Leasehold Improvement # 1			YES
13.2	Leasehold Improvement # 2		4	YES
13.3	Leasehold Improvement # 3			YES
13.4	Leasehold Improvement # 4			YES
14	Franchise		6	NO
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	8.0%		YES
43.1	Certain Energy-Efficient Electrical Generating Equipment	30.0%		YES
45	Computers & Systems Software acq'd post Mar 22/04	45.0%		YES
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	30.0%		YES
47	Distribution System post Feb 22/05	8.0%		YES
50	Computer Equipment Post March 18, 2007	55.0%		YES
3	Building pre 1988	5.0%		YES

Exhibit 5:

COST OF CAPITAL AND RATE OF RETURN

Exhibit 5: Cost Of Capital And Rate Of Return

Tab 1 (of 1): Cost of Capital and Rate of Return

CAPITAL STRUCTURE

The purpose of this evidence is to summarize the method and cost of financing The Applicant's capital requirements for the 2010 test year. The proposed cost of capital (7.31%) has been calculated in accordance with the Board's *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* dated December 20, 2006 (the "Cost of Capital Report") and the Board's most recent directive (letter dated February 24, 2010) on the cost of capital parameters to use for 2010 cost of service applications.

The Applicant currently has different deemed capital structures but with the same debt rates and return in each of its service areas as follows:

Newmarket (2009 IRM)	Ratio %	Cost Rate %	Return %
Long Term Debt – Municipal	52.70%	6.10%	
Long Term Debt - Financial Institutions	0.00%		
Short Term Debt	4.00%	4.47%	
Common Equity	43.30%		8.57%

Tay (2006 EDR)	Ratio %	Cost Rate %	Return %
Long Term Debt - Municipal	50.00%	6.10%	
Long Term Debt - Financial Institutions	0.00%		
Short Term Debt	0.00%	4.47%	
Common Equity	50.00%		8.57%

These components have been updated to reflect the most recent direction from the Board. The Applicant's proposed cost of capital for the 2010 Test Year is summarized in Exhibit 5, Tab 1, Schedule 1, Attachment 1.

The following section outlines The Applicant's cost of capital assumptions with respect to long term debt, short term debt and return on equity.

Attachment 1 (of 1):

Capitalization and Cost of Capital

Capitalization and Cost of Capital

NTP - 2010 Test Year	$	Ratio %	Cost Rate %	Return %	Return	WACC
Long Term Debt - Municipal	35,969,347	56.00%	5.87%		2,111,401	
Short Term Debt	2,569,239	4.00%	2.07%		53,183	
Common Equity	25,692,391	40.00%		9.85%	2,530,701	
Total	**64,230,978**				**4,695,285**	**7.31%**

COST OF CAPITAL

Long Term Debt

The Applicant currently has the following three long-term shareholder debt instruments:

Town of Newmarket

The Town of Newmarket holds a promissory note in the amount of $22,000,000. The current annual debt rate for this instrument (6.10%) matches the deemed debt rate previously set by the Board. For the purpose of preparing this application, The Applicant has used the Board's 2010 deemed long-term debt rate of 5.87% to calculate its cost of long-term debt.

Newmarket Hydro Holdings Inc

Newmarket Hydro Holdings Inc holds a promissory note in the amount of $1,900,000. The current annual debt rate for this instrument (6.10%) matches the deemed debt rate previously set by the Board. For the purpose of preparing this application, The Applicant has used the Board's 2010 deemed long-term debt rate of 5.87% to calculate its cost of long-term debt

The Township of Tay

The Township of Tay holds a promissory note in the amount of $1,742,821. The current annual debt rate for this instrument (6.10%) matches deemed debt rate set by the Board. For the purpose of preparing this application, The Applicant has used the Board's 2010 deemed long-term debt rate of 5.87% to calculate its cost of long-term debt.

Short-Term Debt

The Applicant has $2,569,239 in deemed short-term debt. For the purpose of preparing the cost of capital in this application, The Applicant has used the Board's deemed short-term debt rate of 2.07%.

Return on Equity (ROE)

The Applicant has used the Board's most current deemed ROE of 9.85% for the purpose of preparing its proposed cost of capital in this application.

Capitalization and Cost of Capital

2010 Test	$	Ratio %	Cost Rate %	Return %	Return	WACC
Long Term Debt - Municipal	35,969,347	56.00%	5.87%		2,111,401	
Short Term Debt	2,569,239	4.00%	2.07%		53,183	
Common Equity	25,692,391	40.00%		9.85%	2,530,701	
Total	64,230,977				4,695,285	7.31%

Weighted Average Cost of Debt

2010 Debt Balances

Enter details of debt balances outstanding in 2010 (excluding short-term debt e.g. line of credit)

Description	Amount	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate (a)	Other Costs (b)	Due to Affiliate?	Annual Cost (c)
Town of Newmarket	22,000,000	1-Oct-2001		5.87%			1,291,400
Township of Tay	1,742,821	1-Nov-2000		5.87%			102,304
Newmarket Hydro Holdings Inc	1,900,000	1-May-2009		5.87%			111,530

Description	Effective Rate	Days o/s in 2010	Average Balance	2010 Cost	2010 Ending Balance	Debt o/s USA #	Int. Expense USA #
Town of Newmarket	5.87%	365	22,000,000	1,291,400	0		
Township of Tay	5.87%	365	1,742,821	102,304	0		
Newmarket Hydro Holdings Inc	5.87%	365	1,900,000	111,530	0		
					0		
					0		
					0		
					0		
					0		
					0		
					0		
TOTAL	5.87%		25,642,821	1,505,234	0		

NEWMARKET-TAY POWER DISTRIBUTION LTD.
OEB INTERROGATORIES
EB-2007-0776
EXHIBIT A
PROMISSORY NOTE - NEWMARKET

BE IT RESOLVED THAT:

1. The Promissory Note shall have a principal amount of $22 million.

2. Interest on the Promissory Note shall accrue from October 1, 2001 and be payable at a simple annual rate equal to the rate of interest which the Corporation is from time to time permitted by the Ontario Energy Board to recover in its rates (currently 7.25% per annum) such interest to be paid on the last day of the Corporation's fiscal year.

3. The principal on the Promissory Note shall be due and payable on such terms and at such time as may be further determined by the Director of Finance/Town Treasurer in consultation with the senior officers of the Corporation; provided, however, that in no event, will the repayment terms of the Promissory Note be initially determined or thereafter changed by the Town without giving the Corporation at least 13 months' prior notice thereof.

4. The amount to be added to the stated capital account of the Common Shares in consideration of the issuance of the 1000 Common Shares to the Town approved by the Board of Directors by a resolution dated as of November 1, 2000 shall be $25,806,563.

5. Any officer of the Corporation is authorized and directed to do all such acts and things and to execute or cause to be executed (whether under seal of the Corporation or otherwise) all such instruments, agreements and other documents as in such officer's opinion may be necessary in furtherance of the foregoing.

Approval of Transfer of Shares

1. The transfer of 1001 common shares of the Corporation to Newmarket Hydro Holdings Inc. from the Corporation of the Town of Newmarket with effect from November 1, 2000 is hereby approved.

DATED May 1, 2002

David Weir

NEWMARKET-TAY POWER DISTRIBUTION LTD.
OEB INTERROGATORIES
EB-2007-0776
EXHIBIT A
PROMISSORY NOTE - TAY

SCHEDULE "A"

FORM OF PROMISSORY NOTE

PROMISSORY NOTE

Principal Amount: $1,742,821.00 Due: On Demand

Victoria Harbour, Ontario
November 1, 2000

For value received, the undersigned promises to pay to the order of The Corporation of the Township of Tay (the "Township") at Victoria Harbour, Ontario, the sum of $1,742,821.00 together with interest calculated at the rate of 7.25% per annum and payable semi-annually on June 30th and December 31st in each year with the first interest payment due on December 31, 2000, covering interest accruing from November 1, 2000 to December 31, 2000. Provided that the rate of interest payable under this Promissory Note may be changed from time to time by written agreement between the Township and the undersigned confirmed by a By-law of the Township and a Resolution of the Board of Directors of the undersigned and failing such agreement the interest rate shall continue to remain at the rate of 7.25% per annum until demand for payment has been made.

The undersigned shall not have the right to pre-pay the principal amount outstanding on this Promissory Note in whole or in part at any time other than as required by the Township.

TAY HYDRO-ELECTRIC
DISTRIBUTION COMPANY INC.

Name: R. Crawford
Title: President

I have authority to bind the Corporation.

Exhibit 6:

REVENUE DEFICIENCY OR SUFFICIENCY

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 1 (of 2): Utility Revenue

OVERVIEW OF REVENUE REQUIREMENT

The Applicant's $18,315,226 gross revenue requirement for 2010 contemplates the recovery of its costs of providing distribution service (OM&A and Amortization), a fair return on its invested capital as determined by the Board, and its Payments in Lieu of Taxes ("PILS"). The Applicant estimates revenue offsets totaling $846,361 leaving $17,468,865 to be recovered from distribution rates.

When its forecasted customers and volumes for 2010 are taken into account, The Applicant estimates that its present rates will produce a Gross Revenue Deficiency of $2,617,276 for the 2010 Test Year. The estimated deficiency does not include any consideration for the impact of energy costs or the disposition of variance/deferral accounts.

Details of The Applicant's Distribution Revenue Requirement can be found in the next page in the table 6.1.1.1 – Distribution Revenue Requirement.

The Test Year service gross revenue requirement is derived from the following components:

- Distribution Expenses:
- OM&A and other taxes $7,940,164 (Exhibit 2, Tab 6, Schedule 3, Attachment 2)
- Amortization expense $4,525,690 (Exhibit 2, Tab 5, Schedule 2, Attachment 1)
- Return On Capital $4,695,284 (Exhibit 5, Tab 1 Schedule 1, Attachment 1)
- Allowance for PILs $1,154,088 (Exhibit 5, Tab 1 Schedule 1, Attachment 1)

Table 6.1.1.1 - Distribution Revenue Requirement

	2010 Projection	Non-recurring items (Total)	2010 Normalized
OM&A Expenses	7,940,164		7,940,164
3850-Amortization Expense	4,525,690		4,525,690
Total Distribution Expenses	12,465,854	0	12,465,854
Regulated Return On Capital	4,695,284		4,695,284
PILs (with gross-up)	1,154,088		1,154,088
Service Revenue Requirement	**18,315,226**	**0**	**18,315,226**
Less: Revenue Offsets	846,361		846,361
Base Revenue Requirement	**17,468,865**	**0**	**17,468,865**

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 2 (of 2): Deficiency or Surplus

CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

This exhibit describes the main components used in the calculation of the forecasted revenue deficiency for NTP during the 2010 test year. If existing rates are continued, NTP expects to realize a net revenue shortfall of $1,939,320. The calculation is based on the following:

- Utility income of $2,755,964 from total net revenues of $15,697,951 for 2010 using current rates, along with projected OM&A of $7,766,218, depreciation of $4,525,690, PILs of $476,133 and other taxes totalling $173,946.
- A utility rate base of 64,230,976 projected for the 2010 test year.
- An indicated rate of return of 4.29% as compared to the proposed rate of return of 7.31% which leads to a gross revenue deficiency after PILs of $2,617,275.

Details of the calculation of revenue deficiency are presented at Exhibit 6, Tab 2, Schedule 1, Attachment 1.

Attachment 1 (of 2):

Table of Revenue Deficiency or Surplus

Calculation of Revenue Deficiency or Surplus

	2010 Projection	**2009 Projection**		**Var #**	**Var %**
Utility Income	2,755,964	2,854,873		(98,908)	(3.5%)
Utility Rate Base	64,230,976	59,979,973		4,251,003	7.1%
Indicated Rate of Return	4.29%	4.76%		(0.47%)	(9.9%)
Requested / Approved Rate of Return	7.31%	7.02%		0.29%	4.1%
Sufficiency / (Deficiency) in Return	(3.02%)	(2.26%)		(0.76%)	(33.6%)
Net Revenue Sufficiency / (Deficiency)	**(1,939,320)**	**(1,355,722)**		**(583,599)**	**(43.0%)**
Provision for PILs/Taxes *	(677,955)			(677,955)	0.0%
Gross Revenue Sufficiency / (Deficiency)	**(2,617,275)**	**(1,355,722)**		**(1,261,554)**	**(93.1%)**
Deemed Overall Debt Rate	*5.62%*	*5.99%*		*(0.37%)*	*(6.2%)*
Deemed Cost of Debt	*2,164,584*	*2,156,160*		*8,424*	*0.4%*
Utility Income less Deemed Cost of Debt	*591,380*	*698,713*		*(107,332)*	*(15.4%)*
Return On Deemed Equity	*2.30%*	*2.91%*		*(0.61%)*	*(21.0%)*

UTILITY INCOME

Total Net Revenues	15,697,951	15,779,642		(81,691)	(0.5%)
OM&A Expenses	7,766,218	6,566,288		1,199,930	18.3%
Depreciation & Amortization	4,525,690	4,333,380		192,310	4.4%
Taxes other than PILs / Income Taxes	173,946	246,309		(72,363)	(29.4%)
Total Costs & Expenses	12,465,854	11,145,977		1,319,876	11.8%
Utility Income before Income Taxes / PILs	3,232,097	4,633,665		(1,401,567)	(30.2%)
PILs / Income Taxes	476,133	1,778,792		(1,302,659)	(73.2%)
Utility Income	**2,755,964**	**2,854,873**		**(98,908)**	**(3.5%)**

Statement of Rate Base

Year	2006		2007		2008		2009		2010 Test	
	Additions	Total	Additions	Total	Additions	Total	Additions	Total	Additions	Total
Gross Fixed Assets	5,009,534	87,181,136	8,266,568	95,447,704	7,017,535	102,465,240	5,920,779	108,386,019	10,383,607	118,769,626
Accumulated Depreciation	-3,649,324	-44,409,368	-3,982,935	-48,392,303	-4,089,131	-52,481,434	-4,333,380	-56,814,814	-4,525,690	-61,340,504
Net Fixed Assets	1,344,878	42,771,768	4,283,633	47,055,401	2,928,404	49,983,806	1,587,399	51,571,204	5,857,917	57,429,122
Average		42,730,767	2,182,818	44,913,584	3,606,019	48,519,603	2,257,902	50,777,505	3,722,658	54,500,163
Allowance for Working Funds		9,014,925	121,916	9,136,841	-37,220	9,099,621	102,847	9,202,468	528,346	9,730,814
Rate Base		51,745,692	2,304,734	54,050,426	3,568,799	57,619,224	2,360,749	59,979,973	4,251,005	64,230,978

CAUSES OF REVENUE DEFICIENCY OR SURPLUS

The causes of the $2,716,276 distribution revenue deficiency for the 2010 test year are listed and explained in the Summary of the Application, Exhibit 1, Tab 1, Schedule 3.

Exhibit 7:

COST ALLOCATION

Exhibit 7: Cost Allocation

Tab 1 (of 5): Cost Allocation Model

OVERVIEW AND APPROACH TO THE COST ALLOCATION

Background

Newmarket and Tay completed separate cost allocation models based on each entity's 2004 actual data for purpose of the Board's 2006 Cost Allocation Review – Informational Filing (CAR-IF) reflecting their independent status at the time. These 2006 CAR-IFs were submitted in January 2007. Copies are included electronically with this submission.

The Applicant subsequently used the 2006 Newmarket model to support the 2008 Rate Submission for the Newmarket service area and adopted distribution rates based on an allocation of the actual 2008 costs to customer classes contained in the Settlement Agreement in that proceeding.

To support this 2010 filing, The Applicant has developed a single NTP cost allocation model that combines the independent Newmarket and Tay models using 2010 Test Year forecast costs, throughput, other input values and proposed rates. The allocators used in the combined model were updated based on the most recent available data. Separate Newmarket and Tay models were not maintained to save costs and appropriately reflect the revenue requirement since The Applicant is proposing harmonized rates that reflect the total costs of the integrated utility.

Allocation of Distribution Costs to the Street Light Class

As part of the rate harmonization, The Applicant is proposing a change to the methodology used for allocating costs to the street light class in order to provide an allocation of costs to rate classes that better reflects the principle of cost causality given the configuration of the combined distribution system.

The Applicant's staff was involved with the initial design of the Cost Allocation model in 2006 but since that time The Applicant has been concerned that the methodology embedded in the 2006 CAR-IF model over-allocates costs to the street light class. The 2006 CAR-IF methodology assumes that each street light connection point is the equivalent of a single residential home and allocates costs accordingly. This simplifying assumption is not supported by the cost analysis subsequently conducted by The Applicant based on the configuration of The Applicant's distribution system.

The point of demarcation between The Applicant's distribution system is at the base of the streetlight pole in underground areas and the streetlight bracket in overhead areas. The conductors in the streetlight pole (in underground systems) and the street light bracket (in overhead systems) are not part of The Applicant's distribution system. As such, the number of street light connections is the same as the number of lights in The Applicant's service area. Based on this configuration, the cost to provide the distribution of electricity to a single street light is actually about 25% of the cost of servicing a residential home. The details of this analysis are contained in Exhibit 7, Tab 2, Schedule 3.

SUMMARY OF 2010 COST ALLOCATION MODEL CHANGES

The following is a brief description of the 2010 model and the changes made:

Page I2 LDC Class

Newmarket and Tay currently have the same rate classes. One former Newmarket customer was previously expected to require that a large user class would need to be introduced in the 2010 application. However as mentioned in the load forecast evidence, that customer ceased operations on July 1, 2009. As a result, the currently approved rate classes remain appropriate for the test year. A description of these classes consistent those classes approved by the Board in its Rate Order EB-2007-0776, is provided below.

Residential

This classification refers to a service which is less than 50 kW supplied to single-family dwelling units that is for domestic or household purposes, including seasonal occupancy.

General Service Less Than 50 kW

This classification refers to any service supplied to premises other than those designated as Residential and whose average monthly maximum demand over the past twelve months is less than 50 kW. This includes multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered). For new customers without prior billing history, the peak demand is based on 90% of the proposed capacity or installed transformer.

General Service 50 to 4,999 kW

This classification refers to all non-residential customers whose average monthly maximum demand used for billing purposes over the past twelve months is equal to or greater than 50 kW but less than 5,000 kW. For new customers without prior billing history, the peak demand is based on 90% of the proposed capacity or installed transformer.

Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer is required to provide detailed manufacturer information/ documentation with regard to electrical demand/consumption of the proposed unmetered load.

Sentinel Lighting

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. The distributor will not install any new sentinel lights.

Street Lighting

All services supplied to street lighting equipment owned by or operated for the Town of Newmarket, Township of Tay, the Town of East Gwillimbury or the Province of Ontario shall be classified as Street Lighting Service. This classification refers to roadway and sidewalk lighting operations, controlled by photoelectric cells. The consumption for these customers is based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Page I3 – TB Data

This page was completely updated using combined 2010 Test Year data as provided in Exhibit 2 of this submission. As required with the 2007 CAR – IF, all fixed asset values are based on an average of 2009 Bridge year end and 2010 Test year end values. There are two items on this page that are important to point out:

- The Transformer Ownership Allowance treatment was adjusted to conform to the method suggested by the Board and Interveners subsequent to, and finally used with the 2008 Rate Filing
- Wholesale metering was moved from the Distribution Metering account to the Distribution Station Equipment account. These meters are broken out specifically on I4 BO Assets, but included along with other metering in the 1860 Meters account by the Applicant.

Page I4 BO Assets

This page was also populated with 2010 values with the exception of the Breakout Percentage which was left consistent with the 2007 CAR – IF's. At that time a detailed analysis was undertaken to support the splits for Newmarket and Tay. Since then there have not been any significant changes in system design that would alter those percentages. A weighted average for the two service areas was calculated from the 2007 models and then input to the 2010 combined model.

Page I5 Misc Data

The combined kilometers of roads from the 2007 submissions are used for the purpose of this submission. There has been minimal change since that time and the Applicant believes that any impact would be negligible.

The Fixed Charge included here is a weighted average of the currently approved values for the two service areas.

Page I6 Customer Data

All values on this page were reviewed and updated to 2010 information where appropriate. Consumption and Demand data by class are consistent with Exhibit 3 of this submission which is based on Weather Normalized values provided by Elenchus Research Associates. The details of the forecast are included in their report dated March 10, 2010.

Weighting factors were reviewed and updated to reflect current conditions.

An in-depth study was done regarding Street Light connections. This will be described later in this Exhibit.

The Loss Factor is based on the combined value requested in Exhibit 8 – Rate Design.

Page I7.1 Meter Capital

Meter Capital has changed significantly since the 2007 CAR – IF’s. By the end of 2010, all electro-mechanical and electronic consumption meters will have been replaced by smart meters. The unit values, numbers and types of meters have been updated to reflect this major change.

Page I7.2 Meter Reading

This data has been updated to reflect the estimated costs and weighting for the electronic reads associated with smart meters.

Page I8 Demand Data

The Applicant is of the of the opinion that the demand data used with the 2007 CAR – IF model is representative of the current customer mix with the exception of the General Service 50 to 4,999 kW class where the loss of the Applicant's largest customer in mid 2009 will seriously impact future demand. The Applicant has updated these values by removing the customer's actual 2004 values from each field.

Page I9 Direct Allocation

There is no direct allocation of cost.

Exhibit 7: Cost Allocation

Tab 2 (of 5): Revenue Allocation and Revenue-to-Cost Ratios

COST ALLOCATION RESULTS

The following table is the Q1 Revenue to cost / RR directly from the 2010 The Applicant's Cost Allocation Model. This table provides the detailed costs and revenues assigned to each rate class and shows that each is within the specified parameters established along with the Cost Allocation model.

Cost Allocation Results

	Total	Residential	GS <50	GS>50	Street Light	Sentinel	Unmetered Scattered Load
Distribution Revenue (sale)	$17,468,865	$9,926,666	$2,792,019	$4,388,428	$315,800	$16,508	$29,445
Miscellaneous Revenue (mi)	$846,361	$578,883	$146,466	$112,628	$3,487	$132	$4,765
Total Revenue	**$18,315,226**	**$10,505,549**	**$2,938,485**	**$4,501,056**	**$319,286**	**$16,640**	**$34,210**
Expenses							
Distribution Costs (di)	$2,152,266	$1,305,672	$373,882	$421,388	$45,814	$2,965	$2,546
Customer Related Costs (cu)	$2,739,221	$1,987,139	$412,530	$308,725	$15,144	$407	$15,277
General and Administration (ad)	$3,048,676	$2,026,639	$499,889	$469,478	$40,283	$2,247	$10,140
Depreciation and Amortization (dep)	$4,525,690	$2,799,705	$842,867	$791,795	$81,756	$4,979	$4,588
PILs (INPUT)	$1,154,088	$690,079	$215,134	$227,164	$19,404	$1,213	$1,095
Interest	$2,164,584	$1,294,298	$403,501	$426,064	$36,393	$2,275	$2,054
Total Expenses	**$15,784,526**	**$10,103,532**	**$2,747,803**	**$2,644,613**	**$238,794**	**$14,084**	**$35,699**
Direct Allocation	$0	$0	$0	$0	$0	$0	$0
Allocated Net Income (NI)	$2,530,701	$1,513,215	$471,749	$498,128	$42,548	$2,659	$2,401
Revenue Requirement (includes NI)	$18,315,226	$11,616,747	$3,219,552	$3,142,741	$281,342	$16,744	$38,100
Distribution Plant - Gross	$122,845,880	$74,842,916	$22,957,842	$22,353,412	$2,414,226	$141,126	$136,357
General Plant - Gross	$9,797,293	$5,980,522	$1,834,034	$1,763,477	$197,193	$10,812	$11,254
Accumulated Depreciation	($58,936,823)	($35,831,168)	($10,994,193)	($10,850,012)	($1,127,908)	($70,595)	($62,948)
Capital Contribution	($19,206,186)	($12,370,289)	($3,636,137)	($2,585,232)	($558,183)	($23,931)	($32,414)
Total Net Plant	**$54,500,163**	**$32,621,981**	**$10,161,546**	**$10,681,645**	**$925,329**	**$57,413**	**$52,249**

Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	$56,931,933	$22,685,690	$7,903,261	$25,843,411	$442,014	$25,276	$32,282
OM&A Expenses	$7,940,164	$5,319,450	$1,286,301	$1,199,591	$101,241	$5,618	$27,963
Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$64,872,097***	***$28,005,140***	***$9,189,561***	***$27,043,001***	***$543,255***	***$30,894***	***$60,245***
Working Capital	**$9,730,814**	**$4,200,771**	**$1,378,434**	**$4,056,450**	**$81,488**	**$4,634**	**$9,037**
Total Rate Base	**$64,230,978**	**$36,822,752**	**$11,539,980**	**$14,738,096**	**$1,006,817**	**$62,047**	**$61,285**
Equity Component of Rate Base	**$25,692,391**	**$14,729,101**	**$4,615,992**	**$5,895,238**	**$402,727**	**$24,819**	**$24,514**
Net Income on Allocated Assets	**$2,530,700**	**$402,017**	**$190,682**	**$1,856,442**	**$80,493**	**$2,556**	**($1,489)**
Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	**$2,530,700**	**$402,017**	**$190,682**	**$1,856,442**	**$80,493**	**$2,556**	**($1,489)**
RATIOS ANALYSIS							
REV TO EXP %	100.00%	90.43%	91.27%	143.22%	113.49%	99.38%	89.79%
Rev/Expense Floor/Ceiling per "Application of Cost Allocation for Electricity Distributors" Nov 28, 2007							
Floor		85.00%	80.00%	80.00%	70.00%	70.00%	80.00%
Ceiling		115.00%	120.00%	180.00%	120.00%	120.00%	120.00%

HIGHLIGHT OF SIGNIFICANT CHANGES

There are two significant factors that affect the allocation of costs in the 2010 version of the Cost Allocation Model as compared to the 2006 CAR-IF models for Newmarket and Tay. These are:

1) The introduction and complete installation of smart metering in the the Applicants service area; and

2) The proposed change in the methodology used to allocating costs that are based on Street Light Connections.

The Applicant has analyzed the impacts of these by running the Cost Allocation before and after the changes were made. The following table shows the Revenue to Cost impacts.

IMPACT OF SMART METERING AND STREET LIGHT STUDY

Numbers 1 and 2 above are historical versions of the Model as submitted in previous years. Numbers 3 to 5 show the impacts of the harmonization process along with the impacts of Smart Metering and Street Light Connections. Revenues are held constant throughout the cost allocation comparisons. Three modeling runs were undertaken with the results shown as 3, 4 and 5 in the impact comparison table shown above.

Number 3

The first run shows the impact of the harmonization of Newmarket and Tay costs, revenues and statistical values. Weighting for Meter Capital and Meter Reading or Street Light Capital remains the same as versions 1 & 2.

Number 4

The second run changes the weighting for Meter Capital by updating the installed costs to that of Smart Meters on the Meter Capital page and the reading costs on the Meter Reading page. As expected the major changes take place in the three metered classes. Residential and GS < 50 class ratios drop considerably while GS > 50 increases. The bulk of the costs relating to Smart Metering are in the Residential and GS < 50 classes. Metering in the GS > 50 class was weighted heavily in previous versions of the model.

Number 5

The third run changes the allocation methodology for the street light class. As previously noted, since the initial Cost Allocation Model was developed, The Applicant has suspected that it over-allocates cost to the Street Light Class.

The 2006 Cost Allocation Model assumes that the cost of servicing a street light is the same as it is for a residential home and allocates most costs at the same rate as a result. The Applicant's experience, however, shows that the cost of serving a single street light, which is normally below 200 watts, is considerably less than the cost of serving a house that is many times that load. Every component of the street light installation is a lower capacity and therefore less expensive. In addition, cable runs are shorter on average because street light installations can be daisy chained and installed together in series.

Exhibit 7: Cost Allocation

Tab 3 (of 5): Street Light Cost Allocation

STREET LIGHT COST ALLOCATION STUDY

The Applicant has completed a study that fairly allocates the cost of distributing electricity to the Street Light class. The results of this study show that the cost of providing distribution service to a street light is about 25% of the cost of serving the Residential Class. The following is a brief description of the approach taken with this analysis:

Using Offers to Connect for local developers, The Applicant assessed actual cost data representing the installation of distribution services for more than 1,000 residential customers and just under 300 street lights starting in 2002. Historically, The Applicant does not install these systems, but requests actual cost data to enable appropriate accounting treatment of the costs. Information received for each development includes the following statistical data:

Number of Homes
Number of Transformers
Number of Street Lights
Number of Street Light Pedestals
Average kWh/home/yr
Average kW/Light

Along with the statistical data, The Applicant receives the following cost data for each development:

Primary Conductor
Secondary - Housing
Secondary - Street Lights
Transformers
Services - Lot Line to Meter

Using this data, The Applicant developed a model to allocate the costs between Street Lights and Housing. Table 7-4 shows the weighted average results of the data for six developments that were input to the Model. The sample of 1000 residential and 300 street light connections represents 22.6% of all residential homes and 25.4% of all street lights connected since 2003. The individual results for the six developments varied from about three to one (cost/house to cost/light) to six to one. The individual development design was the determining factor with these ratios. Based on the assessment of its actual service costs, The Applicant contends that the overall ratio of four to one is representative of the utility as a whole and provides a much more accurate cost allocation for street lights than the one to one ratio assumed in the 2006 Cost Allocation Model.

Table 7-4 Street Light Cost Allocation Results

	Development	A	B	C	D	E	F
1	Number of Homes	306	97	159	200	113	126
2	Number of Transformers	33	11	18	27	13	17
3	Number of Street Lights	75	21	28	82	26	64
4	Number of Street Light Pedestals	6	2	2	7	2	10
5	Positions used on Transformers (1 + 4)	312	99	161	207	115	136
6	Average kWh/home/yr in this Development	8880	8880	8880	8880	8556	8880
7	Street Light Average on Hours	50%	50%	50%	50%	50%	50%
8	Hours/Day	24	24	24	24	24	24
9	Days	365	365	365	365	365	365
10	Average kW/Light	0.13	0.13	0.13	0.13	0.13	0.13
11	Annual Housing kWh (1 X 6)	2,717,280	861,360	1,411,920	1,776,000	966,828	1,118,880
12	Annual Street Light kWh (3 x 7 x 8 x 9 x 10)	42,705	11,957	15,943	46,691	14,804	36,442
13	Total Development Load (11 + 12)	2,759,985	873,317	1,427,863	1,822,691	981,632	1,155,322
14	Primary Conductor	221,904	103,077	120,735	653,004	61,400	268,424
15	Secondary Housing	362,863	110,702	237,872	177,750	115,105	142,220
16	Secondary Street Lights	71,305	17,271	13,892	50,757	26,670	53,843
17	Transformer	314,041	106,054	123,842	211,659	70,990	131,988
18	Services - Lot Line to Meter	139,230	44,135	72,345	65,000	39,550	57,330
	Total Development Cost	**1,109,342**	**381,239**	**568,685**	**1,158,170**	**313,715**	**653,805**

Allocation of Capital Cost	Formula							
Homes								
Primary Conductor	kWh of Total	218,470	101,666	119,387	636,276	60,474	259,957	1,401,960
Secondary Housing	100% Housing	362,863	110,702	237,872	177,750	115,105	142,220	1,146,510
Secondary Street Lights	100% Street Lights	0	0	0	0	0	0	0
Transformer	% of Tx Positions Used	308,002	103,911	122,303	204,501	69,755	122,283	931,585
Services - Lot Line to Meter	100% Housing	139,230	44,135	72,345	65,000	39,550	57,330	417,590
Housing Cost		**1,028,564**	**360,414**	**551,906**	**1,083,527**	**284,884**	**581,790**	**3,897,645**
Street Lights								
Primary Conductor	kWh of Total	3,433	1,411	1,348	16,728	926	8,467	26,583
Secondary Housing	100% Housing	0	0	0	0	0	0	0
Secondary Street Lights	100% Street Lights	71,305	17,271	13,892	50,757	26,670	53,843	233,739
Transformer	% of Tx Positions Used	6,039	2,143	1,538	7,158	1,235	9,705	26,989
Services - Lot Line to Meter	100% Housing	0	0	0	1	2	0	0
Street Light Cost		**80,778**	**20,825**	**16,779**	**74,643**	**28,833**	**72,015**	**287,310**
Total Development Cost		**1,109,342**	**381,239**	**568,685**	**1,158,171**	**313,717**	**653,805**	**4,184,956**
Total Cost/Home	# of Homes	3,361	3,716	3,471	5,418	2,521	4,617	3,894
Total Cost/Light	# of Lights	1,077	992	599	910	1,109	1,125	971
Ratio Home Cost to Light Cost		**3.12**	**3.75**	**5.79**	**5.95**	**2.27**	**4.10**	**4.01**

1

STREET LIGHT COST ALLOCATION - RESULTS AND ASSUMPTIONS

This ratio of housing cost to street lighting cost is representative of the underground systems designed and installed since 2002 at which time a pedestal installation became part of the secondary Street Light system (since the pedestals belong to the Town and they did not create a cost increase). The secondary cable for each light runs to the pedestal (about 10 lights / pedestal) and then a single cable runs to a single lug on the transformer and secondary cables for housing are attached to the remaining lugs (average 8.4 houses per transformer). Prior to that time the secondary street light cable ran directly to a single lug on the transformer. Secondary cables for housing are connected to the remaining lugs. This design change to pedestal installations was implemented to improve safety, and did not create any difference (+ or -) in costs for The Applicant. Therefore, the ratio can be applied to all Street Lights fed from underground distribution systems installed since 2002.

Overhead Street Light distribution is somewhat different in design. Typically, a secondary system buss is attached to the poles along a street and houses are fed from that buss. Town owned Street Lights are mounted on some poles and connected to the same secondary system buss that is attached to that pole. The secondary system buss is sized based on the number of homes connected to it and street lights are not considered due to the small load they create. This means that there is no dedicated secondary system buss for street lights other than a very short piece of cable tying the light to the secondary buss on the pole and an extremely small amount of capacity. Incremental costs are quite minor and if anything would increase the home to streetlight cost ratio even if the single streetlight connections were considered. However, since there is no hard data available for overhead fed systems and they represent only about 20% of the Street Lights, The Applicant has decided to apply the lower ratio based on underground connections and has not made any adjustment for the lower price per overhead connection.

For the purpose of the 2010 Cost Allocation Model, The Applicant has conservatively estimated the home-to-streetlight ratio and simply divided the total number of Street Lights by the resultant factor in Exhibit 7 Tab 3 Schedule 1 Table 7-4.

Exhibit 7: Cost Allocation

Tab 4 (of 5): Monthly Fixed Charge

MONTHLY FIXED CHARGE

Table 7.3.1.1 summarizes the output from the 2010 CAR – IF Model and compares those results with the currently approved Fixed Charge for each location and the requested values for the harmonized rates. It also shows that the requested Fixed Charge is within the upper and lower limits established by the Board for each class. The proposed fixed charges shown below are designed to stay within the tolerances while minimizing The Applicant's risk and the overall bill impacts to the customers. This will be covered further in Exhibit 8 – Rate Design.

Table 7.3.1.1 – Monthly Fixed Charge by Class

	Residential	GS <50	GS>50-Regular	Street Light	Sentinel Lights	Unmetered Scattered Load
Fixed Charge Cost Allocation Model Results						
Customer Unit Cost per month - Avoided Cost	7.72	19.38	52.90	0.58	0.42	8.35
Customer Unit Cost per month - Directly Related	11.32	27.46	82.57	0.98	0.71	13.72
Customer Unit Cost per month - Minimum System with PLCC Adjustment	17.43	33.87	125.62	6.57	6.81	15.36
Approved Fixed Charge - Newmarket	**13.45**	**25.21**	**157.20**	**1.76**	**1.76**	**16.41**
Approved Fixed Charge - Tay	**14.59**	**14.72**	**208.38**	**0.69**	**0.72**	**7.35**
Weighted Average Fixed Charge - NT Power	**13.59**	**24.37**	**159.09**	**1.67**	**1.72**	**12.77**
Proposed Fixed Charge	**17.00**	**33.00**	**150.00**	**2.00**	**2.00**	**12.00**
Fixed Charge Floor/Ceiling per "Application of Cost Allocation for Electricity Distributors" Nov 28, 2007						
Floor	7.72	19.38	52.90	0.58	0.42	8.35
Ceiling	20.92	40.64	150.74	7.88	8.17	18.43

Exhibit 7: Cost Allocation

Tab 5 (of 5): Customer Owned Transformer Credit

CUSTOMER OWNED TRANSFORMER CREDIT

Table 7.4.1.1 details the output from the 2010 CAR – IF Model and compares those results with the currently approved Customer Owned Transformer Credit for each location and the requested value for the harmonized rates.

Table 7.4.1.1 – Customer Owned Transformer Credit

Description	Total	Residential	GS <50	GS>50-Regular	Street Lights	Sentinel Lights	Unmetered Scattered Load
Depreciation on Acct 1850 Line Transformers	$400,518	$240,100	$105,008	$46,309	$8,104	$552	$445
Depreciation on General Plant Assigned to Line Transformers	$56,989	$34,599	$14,885	$5,978	$1,369	$82	$76
Acct 5035 - Overhead Distribution Transformers- Operation	$16,516	$9,901	$4,330	$1,910	$334	$23	$18
Acct 5055 - Underground Distribution Transformers - Operation	$71,923	$43,116	$18,857	$8,316	$1,455	$99	$80
Acct 5160 - Maintenance of Line Transformers	$103,597	$62,104	$27,161	$11,978	$2,096	$143	$115
Transformer Allowance Offset (Incl in 5035, 5055 & 5160)	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$32,439	$19,297	$8,606	$3,825	$633	$44	$35
Admin and General Assigned to Line Transformers	$120,000	$70,853	$32,004	$14,277	$2,568	$176	$121
PILs on Line Transformers	$88,823	$53,247	$23,288	$10,270	$1,797	$122	$99
Debt Return on Line Transformers	$166,595	$99,869	$43,678	$19,262	$3,371	$230	$185
Equity Return on Line Transformers	$194,773	$116,761	$51,066	$22,520	$3,941	$268	$217
Total	**$1,252,173**	**$749,847**	**$328,881**	**$144,645**	**$25,670**	**$1,740**	**$1,392**
Billed kW without Line Transformer Allowance		0	0	187,210	14,582	850	0
Billed kWh without Line Transformer Allowance		274,854,374	95,754,008	313,112,560	5,355,339	306,233	391,118
Line Transformation Unit Cost ($/kW) Model Results		**N/A**	**N/A**	**$0.77**	**N/A**	**N/A**	**N/A**
Line Transformation Unit Cost ($/kWh)		**$0.0027**	**$0.0034**	**$0.0005**	**$0.0048**	**$0.0057**	**$0.0036**
Approved Line Transformer Credit - Newmarket/kW				**$0.70**			
Approved Line Transformer Credit - Tay/kW				**$0.60**			
Requested Rate				**$0.70**			

Exhibit 8:

RATE DESIGN

Exhibit 8: Rate Design

Tab 1 (of 9): Rate Design Overview

RATE DESIGN OVERVIEW

This exhibit documents the calculation of The Applicant's proposed distribution rates by rate class for the 2010 Test Year. The rates are based on the revenue requirement shown in Exhibit 8, Tab 2, Schedule 1, Attachment 1 below and include the design changes proposed in Exhibit 7 – Cost Allocation.

The Distribution Rate impact has been offset by other reductions that affect all customers. These reductions significantly reduce and sometimes eliminate the Distribution Rate impact. These reductions are:

1) Elimination of the Smart Meter Adder

2) Reduction of Deferral Account Riders

3) Reduction of Line Loss factor

Exhibit 8: Rate Design

Tab 2 (of 9): Revenue Requirement

REVENUE REQUIREMENT OVERVIEW

The Applicant has determined its total 2010 total service revenue requirement will need to be $18,315,226 in order to recover the cost of providing distribution services to its customers. The revenue offsets as set out in Exhibit 3, in the amount of $846,361 reduce the total service revenue requirement to a base revenue requirement of $17,468,865. This base revenue requirement was used to determine the proposed distribution rates. The revenue requirement is summarized in Exhibit 8, Tab 2, Schedule 1, Attachment 1 below.

Revenue Requirement Details

Distribution Revenue Deficiency

	2010 @ Existing Rates	2010 Test Proposed Rates
Revenue Deficiency		2,617,276
Distribution Revenue at Existing Rates	14,851,590	14,851,590
Distribution Revenue Requirement	14,851,590	17,468,865
Distribution Rate Impact		17.62%
Other Operating Renenue	846,361	846,361
Total Revenue	**15,697,951**	**18,315,226**
Distribution Costs		
Operation Maintenance & Administration	7,766,218	7,766,218
Depreciation & Amortization	4,525,690	4,525,690
Property & Capital Tax	173,946	173,946
Deemed Interest	2,164,584	2,164,584
Total Costs & Expenses	**14,630,438**	**14,630,438**
Income Before Income Tax	1,067,513	3,684,789
Income Tax	476,133	1,154,088
Income After Income Tax	**591,380**	**2,530,701**

Return On Equity w/Pils	**3,684,789**
Distribution Revenue Deficiency	**2,617,276**

Exhibit 8: Rate Design

Tab 3 (of 9): Existing Rates

EXISTING RATES

The existing rate schedule is presented at Exhibit 8, Tab 3, Schedule 1, Attachment 1.

The current rates were approved as part of the proceeding EB-2007-0776 and EB-2007-0578. The Applicant applied for distribution rate adjustments pursuant to the Rebasing process topped with an IRM process. Notice of The Applicant's rate application was given through newspaper publication in The Applicant's service area, and advising how interested parties may intervene in the proceeding or comment on the application.

The Board found that The Applicant's rate application was filed on the basis of the new guidelines.

Rates were adjusted by a price escalator less a productivity factor. Based on the final 2008 data published by Statistics Canada, the Board established the price escalator to be 2.3%.

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0776
EB-2007-0578

Newmarket Service Area
Per EB-2007-0776 Decision

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.06
Service Charge Tax Change Rate Rider – effective until April 30, 2010	$	(0.01)
Distribution Volumetric Rate	$/kWh	0.0136
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kWh	0.0025
Retail Transmission Rate – Network Service Rate	$/kWh	0.0054
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	25.82
Service Charge Tax Change Rate Rider – effective until April 30, 2010	$	(0.03)
Distribution Volumetric Rate	$/kWh	0.0159
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kWh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	157.81
Service Charge Tax Change Rate Rider – effective until April 30, 2010	$	(0.16)
Distribution Volumetric Rate for non-interval metered customers	$/kW	4.3252
Distribution Volumetric Rate for interval metered customers	$/kW	4.4462
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kW	0.1401
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/ kW	(0.0043)
Retail Transmission Rate – Network Service Rate	$/kW	1.9923
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7038
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	16.41
Service Charge Tax Change Rate Rider – effective until April 30, 2010	$	(0.02)
Distribution Volumetric Rate	$/kWh	0.0138
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kWh	0.0092
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
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EB-2007-0776
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Service Charge (per connection)	$	1.76
Distribution Volumetric Rate	$/kW	6.7259
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kW	0.5879
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/ kW	(0.0067)
Retail Transmission Rate – Network Service Rate	$/kW	1.5101
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3447
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.76
Distribution Volumetric Rate	$/kW	8.7412
Distribution Volumetric Deferral Account Rate Rider – effective until April 30, 2010	$/ kW	0.1907
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/ kW	(0.0087)
Retail Transmission Rate – Network Service Rate	$/kW	1.5025
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3172
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	8.50
Statement of account	$	8.50
Duplicate invoices for previous billing	$	3.25
Easement letter	$	8.50
Account history	$	8.50
Returned cheque charge (plus bank charges)	$	16.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	12.50
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	25.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	18.00
Disconnect/Reconnect at meter - during regular Hours	$	50.00
Disconnect/Reconnect at meter – after regular hours	$	120.00
Disconnect/Reconnect at pole – during regular hours	$	160.00
Disconnect/Reconnect at pole – after regular hours	$	315.00
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.70)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Newmarket – Tay Power Distribution Ltd.
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Retail Service Charges (if applicable)

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0365
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0261
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Tay Service Area
Per EB-2007-0578 Decision

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.18
Distribution Volumetric Rate	$/kWh	0.0116
Regulatory Asset Recovery	$/kWh	0.0058
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	17.31
Distribution Volumetric Rate	$/kWh	0.0177
Regulatory Asset Recovery	$/kWh	0.0039
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
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EB-2007-0776
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General Service 50 to 4,999 kW

Service Charge	$	210.93
Distribution Volumetric Rate	$/kW	3.3024
Regulatory Asset Recovery	$/kW	0.9416
Retail Transmission Rate – Network Service Rate	$/kW	1.9747
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6747
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	7.35
Distribution Volumetric Rate	$/kWh	0.0177
Regulatory Asset Recovery	$/kWh	0.0079
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0042
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	0.72
Distribution Volumetric Rate	$/kW	3.2915
Regulatory Asset Recovery	$/kW	7.4173
Retail Transmission Rate – Network Service Rate	$/kW	1.4968
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3217
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.69
Distribution Volumetric Rate	$/kW	3.7705
Regulatory Asset Recovery	$/kW	1.0734
Retail Transmission Rate – Network Service Rate	$/kW	1.4893
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2946
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00

Newmarket – Tay Power Distribution Ltd.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0776
EB-2007-0578

Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect at meter - during regular Hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
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
Service Charge for Access to the Power Poles $/pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0866
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0757
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

2010 DISTRIBUTION REVENUE

In order to design the 2010 rates required to return the Revenue Requirement calculated in Exhibit 8, Tab 2, Schedule 1, Attachment 1, The Applicant first calculated the 2010 distribution revenue that would be earned at the currently approved rates. These rates are applied to projected 2010 statistical data by service territory in the following table.

REVENUE AT CURRENTLY APPROVED DISTRIBUTION RATES

Service Territory: **Newmarket**

	2010 Test			2009 Approved Rates		Revenue		
	kWh	kW	Avg Cust/Con	Fixed	Variable	Fixed	Variable	Total
Residential	242,673,431		25,530	13.44	0.0136	4,117,478	3,300,359	7,417,837
GS<50	90,591,182		2,676	25.18	0.0159	808,580	1,440,400	2,248,980
USL	211,968		75	16.39	0.0138	14,751	2,925	17,676
GS>50	307,538,497	774,860	385	157.04	4.3209	725,525	3,348,093	4,073,617
GS>50 T/A		(597,211)			0.7000		(418,048)	(418,048)
Street Lights	4,917,148	13,360	7,862	1.76	8.7325	166,045	116,666	282,712
Sentinel Lights	297,183	826	393	1.76	6.7192	8,300	5,550	13,850
Total	**646,229,409**					**5,840,680**	**7,795,945**	**13,636,625**

Service Territory: **Tay**

	2010 Test			2009 Approved Rates		Revenue		
	kWh	kW	Avg Cust/Con	Fixed	Variable	Fixed	Variable	Total
Residential	32,180,943		3,840	14.59	0.0101	672,307	325,028	997,335
GS<50	5,162,826		225	14.72	0.0165	39,744	84,980	124,724

USL	179,150		50	7.35	0.0165	4,410	2,947	7,357
GS>50	5,574,063	13,635	16	208.34	2.7726	40,001	37,804	77,806
GS>50 T/A		(4,074)			0.6000		(2,445)	(2,445)
Street Lights	438,191	1,222	712	0.69	3.3617	5,895	4,108	10,003
Sentinel Lights	9,050	24	14	0.72	2.7786	118	67	185
Total	**43,544,223**					**762,476**	**452,489**	**1,214,965**
NTP								**14,851,590**

NTP DISTRIBUTION REVENUE AT WEIGHTED AVERAGE RATES

The above statistics and revenues are then combined to provide the total data for The Applicant by rate class. The revenues are divided by the appropriate statistic to calculate the weighted average rate for each customer class. The following table provides this calculation in detail.

NTP DISTRIBUTION REVENUE AT WEIGHTED AVERAGE RATES

Service Territory: **Newmarket**

	2010 Test			2009 Approved Rates		Revenue		
	kWh	kW	Avg Cust/Con	Fixed	Variable	Fixed	Variable	Total
Residential	242,673,431		25,530	13.44	0.0136	4,117,478	3,300,359	7,417,837
GS<50	90,591,182		2,676	25.18	0.0159	808,580	1,440,400	2,248,980
USL	211,968		75	16.39	0.0138	14,751	2,925	17,676
GS>50	307,538,497	774,860	385	157.04	4.3209	725,525	3,348,093	4,073,617
GS>50 T/A		(597,211)			0.7000		(418,048)	(418,048)
Street Lights	4,917,148	13,360	7,862	1.76	8.7325	166,045	116,666	282,712

Sentinel Lights	297,183	826	393	1.76	6.7192	8,300	5,550	13,850
Total	**646,229,409**					**5,840,680**	**7,795,945**	**13,636,625**

Service Territory: **Tay**

	2010 Test			2009 Approved Rates		Revenue		
	kWh	**kW**	**Avg Cust/Con**	**Fixed**	**Variable**	**Fixed**	**Variable**	**Total**
Residential	32,180,943		3,840	14.59	0.0101	672,307	325,028	997,335
GS<50	5,162,826		225	14.72	0.0165	39,744	84,980	124,724
USL	179,150		50	7.35	0.0165	4,410	2,947	7,357
GS>50	5,574,063	13,635	16	208.34	2.7726	40,001	37,804	77,806
GS>50 T/A		(4,074)			0.6000		(2,445)	(2,445)
Street Lights	438,191	1,222	712	0.69	3.3617	5,895	4,108	10,003
Sentinel Lights	9,050	24	14	0.72	2.7786	118	67	185
Total	**43,544,223**					**762,476**	**452,489**	**1,214,965**
NTP								**14,851,590**

Exhibit 8: Rate Design

Tab 4 (of 9): Proposed Changes to Distribution Rates

OVERVIEW OF FIXED AND VARIABLE CHARGES

The Applicant's first approach to the rate design was to apply the revenue shortfall of $2,617,276 across all rate classes using the variable rate only while maintaining the same percentage of total revenue by rate class. Table below demonstrates the result.

Revenue Shortfall in Variable Revenue

	2010 Test			Revised Rates		Revenue			
	kWh	kW	Avg Cust/Con	Fixed	Variable	Fixed (Actual $ from CIS)	Variable	Total	%
Residential	274,854,374		29,370	13.59	0.0172	4,789,786	5,108,381	9,898,166	56.66%
GS<50	95,754,008		2,901	24.37	0.0207	848,324	1,943,695	2,792,019	15.98%
USL	391,118		125	12.77	0.0195	19,161	10,284	29,445	0.17%
GS>50	313,112,560	788,495	401	159.09	5.5906	765,526	4,043,801	4,809,327	25.12%
GS>50 T/A		(601,285)			0.7000		(420,900)	(420,900)	
Street Lights	5,355,339	14,582	8,574	1.67	10.7830	171,941	172,359	344,300	1.97%
Sentinel Lights	306,233	850	407	1.72	8.6030	8,418	8,090	16,508	0.09%
Total	**689,773,632**	**202,642**				**6,603,156**	**10,865,710**	**17,468,865**	100.00%

CUSTOMER OWNED TRANSFORMER CREDIT

As shown in Exhibit 7 – Cost Allocation, the 2010 CAR – IF Model calculated a value of $0.67/kW for this rate. Since this value is close to the currently approved rate for Newmarket and the vast majority of customers who qualify for this rate are in Newmarket, The Applicant requests that the $0.70/kW rate be approved.

REVENUE BY RATE CLASS - COST ALLOCATION

Once the shortfall had been applied to the rate classes at the same percent of total revenue, the results were entered into the Cost Allocation Model in order to determine if any classes were out of the Revenue to Cost range. It was determined that the Revenue allocated to the Street Light Class took it beyond 120%. $28,500 was then moved from the Street Light Class to the Residential class in order to correct this problem. The Residential class was used for the offset because as a class it is the furthest below the 100% Cost to Revenue goal with the exception of Unmetered Scattered Load which is too small to absorb the amount. The following table shows the results.

Revenue Balancing

	2010 Test			Base Revenue			Revenue Impact	Revised Revenue			
	kWh	kW	Avg Cust /Con	Fixed (Actual $ from CIS)	Variable	Total		Variable Rate	Variable $	Total	%
Residential	274,854,374		29,370	4,789,786	5,108,381	9,898,166	28,500	0.0187	5,136,881	9,926,666	56.82%
GS<50	95,754,008		2,901	848,324	1,943,695	2,792,019	0	0.0203	1,943,695	2,792,019	15.98%
USL	391,118		125	19,161	10,284	29,445	0	0.0263	10,284	29,445	0.17%
GS>50	313,112,560	788,495	401	765,526	4,043,801	4,809,327	0	5.1285	4,043,801	4,809,327	25.12%
GS>50 T/A		-601,285			-420,900	-420,900		0.7000	0	-420,900	
Street Lights	5,355,339	14,582	8,574	171,941	172,359	344,300	-28,500	9.8655	143,859	315,800	1.81%
Sentinel Lights	306,233	850	407	8,418	8,090	16,508	0	9.5178	8,090	16,508	0.09%
Total	**689,773,632**			**6,603,156**	**10,865,710**	**17,468,865**	**0**		**11,286,609**	**17,468,865**	100.00%

FIXED / VARIABLE SPLIT

The output from the Cost Allocation Model is used to ensure that fixed rates fall within the allowable limits. Please see Exhibit 7 – Cost Allocation for more information on this. Also, bill impacts are determined to ensure that no single group of customers is receiving a disproportionate share of the revenue shortfall. Table 7.3.1.1 from Exhibit 7 – Cost Allocation is repeated here to show that the Fixed Charges by class fall within the Floor and Ceiling established for the Model.

	Residential	GS <50	GS>50-Regular	Street Light	Sentinel Lights	Unmetered Scattered Load
Fixed Charge Cost Allocation Model Results						
Customer Unit Cost per month - Avoided Cost	7.72	19.38	52.90	0.58	0.42	8.35
Customer Unit Cost per month - Directly Related	11.32	27.46	82.57	0.98	0.71	13.72
Customer Unit Cost per month - Minimum System with PLCC Adjustment	17.43	33.87	125.62	6.57	6.81	15.36
Approved Fixed Charge - Newmarket	**13.45**	**25.21**	**157.20**	**1.76**	**1.76**	**16.41**
Approved Fixed Charge - Tay	**14.59**	**14.72**	**208.38**	**0.69**	**0.72**	**7.35**
Weighted Average Fixed Charge - NT Power	**13.59**	**24.37**	**159.09**	**1.67**	**1.72**	**12.77**
Proposed Fixed Charge	**17.00**	**33.00**	**150.00**	**2.00**	**2.00**	**12.00**
Fixed Charge Floor/Ceiling per "Application of Cost Allocation for Electricity Distributors" Nov 28, 2007						
Floor	7.72	19.38	52.90	0.58	0.42	8.35
Ceiling	20.92	40.64	150.74	7.88	8.17	18.43

The following table shows the calculation of the variable rates by class once the above fixed rates are applied. The Fixed and Variable Rates that result are the rates that NTP proposes to implement.

Fixed/Variable Split

	2010 Test			Revised Revenue					
	kWh	**kW**	**Avg Cust/Con**	**Proposed Fixed Rate**	**Proposed Variable Rate**	**Fixed $**	**Variable $**	**Total**	**%**
Residential	274,854,374		29,370	17.00	0.0143	5,991,480	3,935,186	9,926,666	56.82%
GS<50	95,754,008		2,901	33.00	0.0172	1,148,796	1,643,223	2,792,019	15.98%
USL	391,118		125	12.00	0.0293	18,000	11,445	29,445	0.17%
GS>50	313,112,560	788,495	401	150.00	5.1840	721,800	4,087,527	4,809,327	25.12%
GS>50 T/A		(601,285)			0.7000	0	(420,900)	(420,900)	
Street Lights	5,355,339	14,582	8,574	2.00	7.5452	205,776	110,024	315,800	1.81%
Sentinel Lights	306,233	850	407	2.00	7.9298	9,768	6,740	16,508	0.09%
Total	**689,773,632**					**8,095,620**	**9,373,245**	**17,468,865**	**100.00%**

Attachment 1 (of 1):

Fixed / Variable Split

Fixed/Variable Split

	2010 Test			Revised Revenue					
	kWh	kW	Avg Cust/Con	Proposed Fixed Rate	Proposed Variable Rate	Fixed $	Variable $	Total	%
Residential	274,854,374		29,370	17.00	0.0143	5,991,480	3,935,186	9,926,666	56.82%
GS<50	95,754,008		2,901	33.00	0.0172	1,148,796	1,643,223	2,792,019	15.98%
USL	391,118		125	12.00	0.0293	18,000	11,445	29,445	0.17%
GS>50	313,112,560	788,495	401	150.00	5.1840	721,800	4,087,527	4,809,327	25.12%
GS>50 T/A		(601,285)			0.7000	0	(420,900)	(420,900)	
Street Lights	5,355,339	14,582	8,574	2.00	7.5452	205,776	110,024	315,800	1.81%
Sentinel Lights	306,233	850	407	2.00	7.9298	9,768	6,740	16,508	0.09%
Total	**689,773,632**					**8,095,620**	**9,373,245**	**17,468,865**	**100.00%**

Exhibit 8: Rate Design

Tab 5 (of 9): Transmission Rates

RETAIL TRANSMISSION SERVICE RATES (RTSR)

Wholesale Transmission Rates are being adjusted periodically and it is important to reflect these changes in the rates to the customers. The most recent change was effective January 1, 2010 and these rates have been used to calculate the costs that we should recover through 2010. The following table shows these rates:

Transmission Network	2.97
Transmission Connection (includes Transformer and Line Connection rates)	2.44

The Applicant first established the amount of Transmission Recovery that would result from existing rates at 2010 projected kWh and kW for each location. These results were summed in order to establish a harmonized total. These totals were then compared to the Wholesale Cost and prorated (up or down) to establish the Transmission Recovery by class to match that cost. Proposed rates were then established by dividing the prorated dollars by the kWh or kW for each class. The results do not vary significantly from current approved levels and do not impact customer bills appreciably.

The table below shows the details of the RTSR calculation:

Calculation of RTS Rates

Wholesale Cost	Network		Connection	
	Rate	**$**	**Rate**	**$**
NTP Wholesale (see Exhibit 2 - Rate Base)	2.97	4,525,660	2.44	3,368,696
Total Wholesale		**4,525,660**		**3,368,696**

Recovery at Current Rates & Proposed Loss Factor							
		kWh/kW	**Loss Factor**	**Network**		**Connection**	
Tay							
Residential	**kWh**	32,180,943	1.0356	0.0053	176,627	0.0047	156,631
GS<50	**kWh**	5,162,826	1.0356	0.0048	25,663	0.0042	22,455
USL	**kWh**	179,150	1.0356	0.0048	891	0.0042	779
GS>50	**kW**	13,635		1.9747	26,925	1.6747	22,835
Street Lights	**kW**	1,222		1.4893	2,046	1.2946	1,582
Sentinel Lights	**kW**	24		1.4968	31	1.3217	32
Total					**232,183**		**204,314**
Newmarket							
Residential	**kWh**	242,673,431	1.0356	0.0054	1,357,056	0.0048	1,206,272
GS<50	**kWh**	90,591,182	1.0356	0.0049	459,689	0.0043	403,400
USL	**kWh**	211,968	1.0356	0.0049	1,076	0.0043	944
GS>50	**kW**	774,860		1.9923	1,543,754	1.7038	1,320,206
Street Lights	**kW**	13,360		1.5025	20,073	1.3172	17,598
Sentinel Lights	**kW**	826		1.5101	1,247	1.3447	1,111
Total					**3,382,895**		**2,949,531**
Total recovery at weighted average rates (NT Power)							
Residential	**kWh**	274,854,374	1.0356	0.0054	1,533,683	0.0048	1,362,904
GS<50	**kWh**	95,754,008	1.0356	0.0049	485,352	0.0043	425,856
USL	**kWh**	391,118	1.0356	0.0049	1,966	0.0043	1,723
GS>50	**kW**	788,495		1.9920	1,570,679	1.7033	1,343,041
Street Lights	**kW**	14,582		1.5169	22,120	1.3153	19,180
Sentinel Lights	**kW**	850		1.5040	1,278	1.3441	1,142
Total					**3,615,078**		**3,153,845**
2010 Transmission Rates							
Residential	**kWh**	274,854,374	1.0356	**0.0067**	1,919,994	**0.0051**	1,455,749
GS<50	**kWh**	95,754,008	1.0356	**0.0061**	607,605	**0.0046**	454,866
USL	**kWh**	391,118	1.0356	**0.0061**	2,461	**0.0045**	1,840
GS>50	**kW**	788,495		**2.4937**	1,966,308	**1.8193**	1,434,533
Street Lights	**kW**	14,582		**1.8990**	27,692	**1.4049**	20,486
Sentinel Lights	**kW**	850		**1.8829**	1,600	**1.4356**	1,220
Total					**4,525,660**		**3,368,696**

Exhibit 8: Rate Design

Tab 6 (of 9): Low Voltage Rates

LOW VOLTAGE CHARGES

The Applicant incurs Low Voltage charges of about $30,000 from Hydro One at the wholesale level in the Tay service territory. When rates are calculated for these charges in the same way that RTS rates are calculated above, the resulting rates are very minor and in some cases go to 5 decimal places. As a result The Applicant requests that the rate for Low Voltage Charges be set at $0.00 and the recovery be made through the Variance Account dispositions in future rates.

			Apportioned Wholesale Cost	Calculated Rate
Residential	**kWh**	**274,854,374**	12,828.44	0.00005
GS<50	**kWh**	**95,754,008**	4,037.58	0.00004
USL	**kWh**	**391,118**	16.35	0.00004
GS>50	**kW**	**788,495**	12,923.82	0.01639
Street Lights	**kW**	**14,582**	183.08	0.01256
Sentinel Lights	**kW**	**850**	10.72	0.01261
Total			**30,000.00**	

Exhibit 8: Rate Design

Tab 7 (of 9): Loss Adjustment Factors

LOSS ADJUSTMENT FACTORS

Line losses have decreased over the last 5 years. Currently approved levels have Tay at 1.0866 and Newmarket at 1.0365. It is important to point out that Tay is embedded with Hydro One and more than 50% of their historical loss factor is due to the Hydro One loss adjustment factor (currently 1.04434). The following table shows the history of the combined values for The Applicant.

		2005	2006	2007	2008	2009
A	"Wholesale" kWh (IESO)	775,000,833	753,310,366	763,702,912	754,258,226	706,737,142
B	"Wholesale" kWh for Large User (IESO)	0	0	0		
C	Net "Wholesale" kWh (A)-(B)	775,000,833	753,310,366	763,702,912	754,258,226	706,737,142
D	"Retail" kWh (Distributor)	744,939,447	724,325,986	738,804,880	735,465,676	680,544,126
E	"Retail" kWh for Large User (IESO)	0	0	0	0	0
F	Net "Retail" kWh (D)-(E)	744,939,447	724,325,986	738,804,880	735,465,676	680,544,126
G	TLF Loss Factor [(C)/(F)]	1.04035	1.04002	1.03370	1.02555	1.03849
	DLF	1.03569	1.03536	1.02907	1.02096	1.03384
	SFLF	1.0045	1.0045	1.0045	1.0045	1.0045
H	Total Loss Factor Adjustment Secondary Metered Customers(5 year average)					1.0356
I	Total Loss Factor Adjustment Primary Metered Customers(5 year average)					1.02522

The Applicant requests that the 5 year average loss adjustment factors of 1.0356 (Secondary Metered) and 1.02522 (Primary Metered) be approved.

The Applicant cannot comment with certainty on the reasons for the decline in the losses over recent years, but offers the following as contributing factors:

- The amalgamation of Tay and Newmarket provided the opportunity for The Applicant to review metering installations within the new combined company. This review resulted in some changes in billing multipliers (plus and minus) the net of which had a positive effect on the losses.

- The Applicant has been a leader in recent years in the search for by-passed meter installations. The reduction/elimination of these illicit installations has a positive effect on the losses.

- The Applicant also feels that the installation of Smart Meters has had a positive effect in the area of losses as well. The conversion basically provided an audit of each and every location where Smart Meters are installed. Also, the Smart Meters provide feedback if it is removed or tampered with and therefore deters this type of activity.

Exhibit 8: Rate Design

Tab 8 (of 9): Adjustment Rate and Factor

HOURLY VS. 15 MINUTE ADJUSTMENT RATE AND FACTOR

The following description was copied directly from Exhibit 9.1.5 of the 2008 Rate Application. This adjustment was approved at that time and The Applicant seeks approval to continue using the 2.8% adjustment as described below. The rate of $5.32891/kW requested with this Application is simply the previously settled base rate of $5.18396/kw plus 2.8%. Please note that this does <u>not</u> represent a rate increase to the interval metered customers, but is simply a means of continuing an automated process that was previously done manually.

9.1.5 Hourly vs. 15 Minute Adjustment Rate and Factor (2008 Application)

In 2002, The Applicant commenced installing interval meters on its larger GS >50 Customers. Historically, distribution demand rates have been based on readings that are established on a rolling 15 minute peak using 5 minute intervals. However, transmission rates are based on a rolling hourly peak using the 5 minute intervals.

Currently the Wholesale Settlement System provides billing data that satisfies the transmission component of the customers' bills. To satisfy the distribution demand readings, The Applicant manually derives the 15 minute information from raw wholesale settlement data. As more interval meters are installed, this becomes a burdensome task. With this submission, The Applicant requests a rate increase to automate this process. The increase requested is 2.8% above the proposed base rate for this class.

The Applicant has maintained data on a customer by customer basis since meters were installed and have used this data to calculate the revised rate.

Of note, this issue was addressed by Milton Hydro Distribution Inc. several years ago. Milton is an industry leader with interval meters and received approval to handle the issue through an increased interval demand rate. Milton now has all of its GS >50 customers on interval meters, but the factor is a component of its single rate.

The following chart is the summary of the data collected and the calculation of the requested rate.

Read Type	GS>50
15m kW Demand Billed since Installation	**1,608,804**
60m kW Demand Billed since Installation	**1,565,043**
kW Difference	**43,760**
Difference Percentage	**2.80%**
kW Billing Factor	**1.0280**
Distribution KW Rate Requested (Thermal Demand Meter old style)	**3.5675**
Distribution KW Rate (Interval Meter)	**3.6672**

This is a list of each of The Applicant's customers that have interval meters and the total 15 minute and hourly demands that have been used for billing transmission and distribution.

Customer	kW since meter installed		
	15m Demands (Distribution)	60m Demands (Transmission)	15m Higher By
1	43,168	41,431	4.19%
2	11,857	11,576	2.42%
3	2,688	2,558	5.06%
4	26,642	25,843	3.09%
5	5,093	4,951	2.87%
6	16,905	16,625	1.68%
7	6,501	6,116	6.30%
8	8,718	8,437	3.32%
9	4,657	4,511	3.25%
10	5,948	5,797	2.62%
11	7,442	7,282	2.20%
12	3,814	3,636	4.89%
13	3,524	3,359	4.91%
14	5,954	5,285	12.66%
15	5,939	5,608	5.91%
16	3,893	3,819	1.94%
17	3,807	3,748	1.57%
18	8,158	7,747	5.31%
19	3,093	2,943	5.10%
20	5,479	5,263	4.10%
21	4,495	4,339	3.59%
22	2,987	2,766	8.00%
23	2,737	2,579	6.12%
24	7,308	7,006	4.31%
25	3,316	3,049	8.75%
26	6,276	5,915	6.10%
27	4,314	4,163	3.64%
28	6,582	6,362	3.47%
29	717	639	12.30%
30	143	137	4.92%
31	45,303	43,908	3.18%
32	63,826	62,377	2.32%
33	32,189	30,027	7.20%
34	109,354	107,649	1.58%
35	90,630	89,574	1.18%

Customer	kW since meter installed		
	15m Demands (Distribution)	60m Demands (Transmission)	15m Higher By
36	61,351	59,144	3.73%
37	347,359	342,981	1.28%
38	84,056	80,540	4.36%
39	27,191	26,629	2.11%
40	31,057	29,586	4.97%
41	34,593	33,438	3.45%
42	5,419	5,301	2.23%
43	6,717	6,223	7.94%
44	17,922	17,248	3.91%
45	5,518	5,293	4.25%
46	5,780	5,551	4.12%
47	14,856	14,499	2.46%
48	17,806	16,860	5.61%
49	20,192	19,302	4.61%
50	12,527	12,128	3.29%
51	1,389	1,344	3.29%
52	6,682	6,501	2.79%
53	12,387	11,968	3.50%
54	2,685	2,444	9.84%
55	1,976	1,891	4.47%
56	4,601	4,476	2.78%
57	33,276	32,708	1.74%
58	36,349	35,056	3.69%
59	27,952	27,422	1.93%
60	8,042	7,429	8.24%
61	34,070	33,486	1.74%
62	3,668	3,546	3.44%
63	18,449	17,902	3.05%
64	11,931	11,407	4.60%
65	16,213	15,301	5.96%
66	24,824	24,400	1.74%
67	25,793	25,324	1.85%
68	11,441	11,093	3.13%
69	26,354	25,874	1.86%
70	3,948	3,771	4.69%
71	6,505	6,426	1.23%
72	13,245	12,740	3.97%
73	3,544	3,486	1.66%
74	6,477	6,402	1.18%
75	3,741	3,581	4.48%
76	5,610	5,514	1.75%
77	1,849	1,804	2.51%
	323,281	**314,671**	**2.74%**
	1,608,804	**1,565,043**	**2.80%**

Exhibit 8: Rate Design

Tab 9 (of 9): Rate Schedules and Bill Impacts

RATE CLASSES

As discussed in Exhibit 7- Cost Allocation, The Applicant would like to keep the existing Rate Classes. In summary these are:

- Residential
- General Service Less Than 50 kW
- General Service 50 to 4,999 kW
- Unmetered Scattered Load
- Sentinel Lighting
- Street Lighting

EXISTING AND PROPOSED RATE SCHEDULES

The following table highlights the existing approved rates as shown above in Exhibit 8-3-1-1 and the requested rates.

Existing and Proposed Rate Schedules

Class	Newmarket 2009 Approved Rates	Tay 2007 Approved Rates	NT Power Proposed 2010 Rates
RESIDENTIAL			
Distribution kWh Rate	0.01360	0.01010	0.01432
Monthly Service Charge/Customer/Month	13.44000	14.59000	17.00000
Smart Meter Adder	0.61000	2.59000	0.00000
Deferral Account Recovery/kWh	0.00250	0.00580	0.00237
LV kWh Rate	0.00000	0.00150	0.00000
Wholesale Market Services/kWh	0.00520	0.00520	0.00520
Rural Rate Protection/kWh	0.00130	0.00100	0.00130
Transmission Network/kWh	0.00540	0.00530	0.00675
Transmission Connection/kWh	0.00480	0.00470	0.00511
Commodity - To 600 kWh	0.05700	0.05700	0.05700
Commodity - > 600 kWh	0.06600	0.06600	0.06600
Debt Retirement Charge/kWh	0.00700	0.00700	0.00700
Regulated Price Plan Admin Charge/Cust/Mn	0.25000	0.25000	0.25000
GENERAL SERVICE < 50 KW			
Distribution kWh Rate	0.01590	0.01646	0.01716
Monthly Service Charge/Customer/Month	25.18000	14.72000	33.00000
Smart Meter Adder	0.61000	2.59000	0.00000
Deferral Account Recovery/kWh	0.00120	0.00390	0.00181
LV kWh Rate	0.00000	0.00124	0.00000
Wholesale Market Services/kWh	0.00520	0.00520	0.00520
Rural Rate Protection/kWh	0.00130	0.00100	0.00130
Transmission Network/kWh	0.00490	0.00480	0.00613
Transmission Connection/kWh	0.00430	0.00420	0.00459
Commodity - To 750 kWh	0.05700	0.05700	0.05700
Commodity - > 750 kWh	0.06600	0.06600	0.06600
Debt Retirement Charge/kWh	0.00700	0.00700	0.00700
Regulated Price Plan Admin Charge/Cust/Mn	0.25000	0.25000	0.25000

GENERAL SERVICE < 50 KW USL			
Distribution kWh Rate	0.01380	0.01645	0.02926
Monthly Service Charge/Customer/Month	16.39000	7.35000	12.00000
Deferral Account Recovery/kWh	0.00920	0.00790	0.00074
LV kWh Rate	0.00000	0.00125	0.00000
Wholesale Market Services/kWh	0.00520	0.00520	0.00520
Rural Rate Protection/kWh	0.00130	0.00100	0.00130
Transmission Network/kWh	0.00490	0.00480	0.00608
Transmission Connection/kWh	0.00430	0.00420	0.00454
Commodity - To 750 kWh	0.05700	0.05700	0.05700
Commodity - > 750 kWh	0.06600	0.06600	0.06600
Debt Retirement Charge/kWh	0.00700	0.00700	0.00700
Regulated Price Plan Admin Charge/Cust/Mn	0.25000	0.25000	0.25000
GENERAL SERVICE > 50 KW			
Distribution KW Rate (Thermal Demand Meter old style)	4.32090	2.77260	5.18396
Distribution KW Rate (Interval Meter)	4.44190	2.77260	5.32891
Transformer Allowance/kW	-0.70000	-0.60000	-0.70000
Monthly Service Charge/Customer/Month	157.04000	208.38000	150.00000
Smart Meter Adder	0.61000	2.59000	0.00000
Deferral Account Recovery/kW	0.14010	0.94160	0.21181
LV kW Rate	0.00000	0.53000	0.00000
Wholesale Market Services/kWh	0.00520	0.00520	0.00520
Rural Rate Protection/kWh	0.00130	0.00100	0.00130
Transmission Network/kW	1.99230	1.97470	2.49375
Transmission Connection/kW	1.70380	1.67470	1.81933
Commodity - To 750 kWh	0.05700	0.05700	0.05700
Commodity - > 750 kWh	0.06600	0.06600	0.06600
Debt Retirement Charge/kWh	0.00700	0.00700	0.00700
Regulated Price Plan Admin Charge/Cust/Mn	0.25000	0.25000	0.25000
SENTINEL LIGHTS			
Distribution KW Rate	6.71920	2.77910	7.92981
Monthly Service Charge/Connection/Month	1.76000	0.72000	2.00000
Deferral Account Recovery/kW	0.58790	7.41730	0.18218
LV kW Rate	0.00000	0.51300	0.00000

Wholesale Market Services/kWh	0.00520	0.00520	0.00520
Rural Rate Protection/kWh	0.00130	0.00100	0.00130
Transmission Network/kW	1.51010	1.49680	1.88285
Transmission Connection/kW	1.34470	1.32170	1.43561
Commodity - To 750 kWh	0.05700	0.05700	0.05700
Commodity - > 750 kWh	0.06600	0.06600	0.06600
Debt Retirement Charge	0.00700	0.00700	0.00700
Regulated Price Plan Admin Charge/Cust/Mn	0.25000	0.25000	0.25000
STREET LIGHTING			
Distribution KW Rate	8.73250	3.36230	7.54518
Monthly Service Charge/Connection/Month	1.76000	0.69000	2.00000
Deferral Account Recovery/kW	0.19070	1.07340	0.16828
LV kW Rate	0.00000	0.40879	0.00000
Wholesale Market Services/kWh	0.00520	0.00520	0.00520
Rural Rate Protection/kWh	0.00130	0.00100	0.00130
Transmission Network/kW	1.50250	1.48930	1.89902
Transmission Connection/kW	1.31720	1.29460	1.40491
Commodity - To 750 kWh	0.05700	0.05700	0.05700
Commodity - > 750 kWh	0.06600	0.06600	0.06600
Debt Retirement Charge/kWh	0.00700	0.00700	0.00700
Regulated Price Plan Admin Charge/Cust/Mn	0.25000	0.25000	0.25000
Total Loss Factor - Secondary Metered Customer	1.03650	1.08660	1.03558
Total Loss Factor - Primary Metered Customer	N/A	1.07570	1.02522

SUMMARY OF BILL IMPACTS

The Applicant has analyzed the impacts of these changes to our customers at both locations at the consumption/demand levels requested by the Ontario Energy Board. The following Exhibit 8, Tab 9, Schedule 3 Attachment 1 is a summary of the impacts to the customers:

Summary of Bill Impacts

Summary of Bill Impacts Based on Total Bill Before Tax					
Class/Location	**kWh/Mn**	**kW/Mn**	**Old Bill $**	**New Bill $**	**% Change**
Residential - Newmarket	100		24.25	27.42	13.09%
	250		39.17	42.68	8.96%
	500		64.05	68.11	6.35%
	800		95.95	100.69	4.93%
	1,000		117.72	122.90	4.40%
Residential - Tay	100		27.80	27.42	-1.35%
	250		43.35	42.68	-1.54%
	500		69.27	68.11	-1.67%
	800		102.80	100.69	-2.05%
	1,000		125.49	122.90	-2.06%
GS Less than 50 kW - Newmarket	1,000		128.07	138.65	8.26%
	2,000		236.85	250.80	5.89%
	5,000		563.20	587.25	4.27%
	10,000		1,107.11	1,148.00	3.69%
GS Less than 50 kW - Tay	1,000		127.64	138.65	8.62%
	2,000		244.47	250.80	2.59%
	5,000		594.97	587.25	-1.30%
	10,000		1,179.13	1,148.00	-2.64%
Unmetered Scattered Load - Newmarket	200		36.53	32.58	-10.81%
	500		66.37	63.08	-4.96%
Unmetered Scattered Load - Tay	200		29.81	32.58	9.30%
	500		63.12	63.08	-0.07%
GS Greater Than 50 kW - Newmarket	25,000	60	2,694.23	2,778.01	3.11%
Analog/Smart Meter	40,000	100	4,182.71	4,327.55	3.46%
Analog/Smart Meter	200,000	500	20,308.95	21,063.77	3.72%
Analog/Smart Meter	400,000	1,000	40,466.75	41,984.05	3.75%
GS Greater Than 50 kW - Tay	25,000	60	2,814.40	2,778.01	-1.29%
Analog/Smart Meter	40,000	100	4,351.93	4,327.55	-0.56%
Analog/Smart Meter	200,000	500	20,941.77	21,063.77	0.58%
Street Lights -Newmarket	402,353	1,092	61,424.84	62,462.41	1.69%

Street Lights -Tay	37,201	104	4,593.79	5,799.69	26.25%
Sentinel Lts - Newmarket	60	0.18	8.46	8.69	2.72%
Sentinel Lts - Tay	60	0.18	7.87	8.66	10.04%

DETAILED BILL IMPACTS

Residential

Newmarket

(Average Consumption = 792 kWh/Mn)

Overall rate impact range for this group of customers is + 8.96% or $3.51 at the 250 kWh level to +3.27% or $7.41 at the 2,000 kWh level.

At the average consumption level within this class, the total bill is impacted by +4.93%.

The following table details the impacts at the 800 kWh level. Full detailed calculations as prescribed in OEB Appendix 2.4 appear at the end of this Exhibit in the Detailed Calculations – Newmarket.

Residential	**2009 BILL**			**2010 BILL**			**IMPACT**	
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**Change $**	**Change %**
Monthly Service Charge			13.44			17.00	3.56	26.49%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	800	0.01360	10.88	800	0.01432	11.45	0.57	5.27%
Deferred Account Recovery & LV Adder	800	0.00250	2.00	800	0.00237	1.90	(0.10)	-5.22%
Sub-Total			**26.93**			**30.35**	**3.42**	**12.70%**
Debt Retirement Charge	800	0.00700	5.60	800	0.00700	5.60	0.00	0.00%
Wholesale Market Services	829	0.00520	4.31	828	0.00520	4.31	(0.00)	-0.09%
Rural Rate Assistance	829	0.00130	1.08	828	0.00130	1.08	(0.00)	-0.09%
Transmission Network	829	0.00540	4.48	828	0.00675	5.59	1.11	24.81%
Transmission Connection	829	0.00480	3.98	828	0.00511	4.24	0.26	6.46%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	229	0.06600	15.13	228	0.06600	15.08	(0.05)	-0.32%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**95.95**			**100.56**	**4.73**	**4.93%**

Tay

(Average Consumption = 698 kWh/Mn)

Overall rate impact range for this group of customers is – 1.54% or ($0.67) at the 250 kWh level to -2.09% or ($5.00) at the 2,000 kWh level.

At the average consumption level within this class, the total bill is impacted by -2.05% or ($2.11). The Distribution Fixed and Variable components account for +25.5% increase which is fully offset by the following:

- Elimination of the Smart Meter Adder
- Reduction of the Deferral Account Recovery Rate
- Reduction of Total Loss Factor

Although these are the same reductions as those mentioned for Newmarket, they are more substantial for the Tay customers. All customers in this class will receive reductions in their bills as a result of this submission.

The following table details the impacts at the 800 kWh level. Full detailed calculations as prescribed in OEB Appendix 2.4 appear at the end of this Exhibit in Detailed Calculations – Tay.

Residential	**2009 BILL**			**2010 BILL**			**IMPACT**	
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**Change $**	**Change %**
Monthly Service Charge			14.59			17.00	2.41	16.52%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	800	0.01010	8.08	800	0.01432	11.45	3.37	41.76%
Deferred Account Recovery & LV Adder	800	0.00704	5.63	800	0.00237	1.90	(3.74)	-66.34%
Sub-Total			**30.89**			**30.22**	**(0.54)**	**-1.76%**
Debt Retirement Charge	800	0.00700	5.60	800	0.00700	5.60	0.00	0.00%
Wholesale Market Services	869	0.00520	4.52	828	0.00520	4.31	(0.21)	-4.70%
Rural Rate Assistance	869	0.00100	0.87	828	0.00130	1.08	0.21	23.90%
Transmission Network	869	0.00530	4.61	828	0.00675	5.59	0.98	21.30%
Transmission Connection	869	0.00470	4.09	828	0.00511	4.24	0.15	3.71%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	269	0.06600	17.77	228	0.06600	15.08	(2.69)	-15.16%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**102.80**			**100.69**	**(2.11)**	**-2.05%**

General Service Less Than 50 kW

General Service Less Than 50 kW – Newmarket

(Average Consumption = 2,821 kWh/mn)

Overall rate impact range for this group of customers is +8.26% or $10.58 at the 1,000 kWh level to +3.50% or $57.76 at the 15,000 kWh level.

At the average consumption level within this class, the total bill is impacted by +5.89%. The Distribution Fixed and Variable components account for +18.1% increase which is offset by the following:

- Elimination of the Smart Meter Adder
- Elimination of the Deferral Account Recovery Rate
- Reduction of Total Loss Factor
- There are no customers that are outside of the + 10% limit.

Full detailed calculations as prescribed in OEB Appendix 2.4 appear at the end of this Exhibit in Detailed Calculations – Newmarket.

General Service Less Than 50 kW – Tay

(Average Consumption = 1,912 kWh/mn)

Overall rate impact range for this group of customers is +8.62% or $11.01 at the 1,000 kWh level to -3.09% or -$55..54 at the 15,000 kWh level.

At the average consumption level within this class, the total bill is impacted by +2.59%.or $6.33. The Distribution Fixed and Variable components account for +41.3% increase which is offset by the following:

- Elimination of the Smart Meter Adder
- Elimination of the Deferral Account Recovery Rate
- Reduction of Total Loss Factor

Although these are the same reductions as those mentioned for Newmarket, they are more substantial for the Tay customers. There are no customers that are outside of the + 10% limit.

Full detailed calculations as prescribed in OEB Appendix 2.4 appear at the end of this Exhibit Detailed Calculations – Tay.

Unmetered Scattered Load

Unmetered Scattered Load - Newmarket

As shown in Table 8.9.3.1, all levels receive cost reductions. This class is very small within the Newmarket Service territory since most installations that are unmetered in other jurisdictions have been traditionally metered in Newmarket. The unmetered customers do not receive any allocation of costs relating to Smart Meters. The following factors contribute to the overall reductions:

- Reduction of average Distribution Rates. This is attributed to rate harmonization in that the Tay service area rates for this class are lower than those in Newmarket.
- Reduction of the Deferral Account Recovery Rate
- Reduction of Total Loss Factor

Full detailed calculations as prescribed in OEB Appendix 2.4 appear at the end of this Exhibit in Detailed Calculations – Newmarket.

Unmetered Scattered Load – Tay

This class is proportionately larger in the Tay Service territory and have enjoyed lower rates in recent years. Overall rate impacts range from -.07% or -$0.04 at the 500 kWh level to +9.3% or $2.77 at the 200 kWh level. They do not receive any allocation of costs related to Smart Meters. Distribution Increases are offset by the following reductions:

- Reduction of the Deferral Account Recovery Rate
- Reduction of Total Loss Factor

Full detailed calculations as prescribed in OEB Appendix 2.4 appear at the end of this Exhibit in Detailed Calculations – Tay.

General Service Greater Than 50 kW

General Service Greater Than 50 kW – Newmarket

(Average Consumption = 66,567 kWh and 168 kW/mn)

Overall impacts within this class are consistent with all customers falling within a band of 3.11 to 3.75%. In addition to other impacts, this class is not seriously affected by the installation of Smart Meters.

Full detailed calculations as prescribed in OEB Appendix 2.4 appear at the end of this Exhibit in Detailed Calculations – Newmarket.

General Service Greater Than 50 kW – Tay

(Average Consumption = 29,032 kWh and 71 kW/mn)

Overall impacts within this class are minimal with all customers receiving bill changes ranging from about -1.29% to +.73% with this application. In addition to other impacts, this class is not seriously affected by the installation of Smart Meters. Also, it is important to note that there are < 20 customers in this group with the largest consuming about 120,000 kWh and 220 kW/Mn.

Full detailed calculations as prescribed in OEB Appendix 2.4 appear at the end of this Exhibit in Detailed Calculations – Tay.

Street Lights

Street Lights – Newmarket

(Annual Consumption = 402,353 kWh and 1,092 kW/mn)

There is only one customer represented here; namely the Town of Newmarket. The bill calculation shown in Detailed Calculations – Newmarket represents an average monthly bill for 2010. The class was affected by the analysis described in Exhibit 7 – Cost Allocation. Distribution Rates were significantly adjusted with The Applicant's 2008 Application. Overall impact of this application is minimal.

Street Lights - Tay

(Annual Consumption = 37,201 kWh and 104 kW/mn)

There is only one customer represented here; namely the Township of Tay. The bill calculation shown in Detailed Bill Calculations – Tay represents an average monthly bill for 2010 using projected statistics. This Application represents the first adjustment that is supported by the Cost Allocation Model. As a result, the increase is more severe to this customer than the Town of Newmarket, but brings the total to an acceptable Cost/Revenue Ratio in one step. Fixed and Variable Distribution charges increase by 162.7%, but are somewhat offset by the following reductions leaving a total bill increase of 26.25%

- Reduction of the Deferral Account Recovery Rate
- Reduction of Total Loss Factor

Sentinel Lights

Sentinel Lights - Newmarket

Sentinel Lights are typically anywhere from one to a few lights that are billed in conjunction with another account (usually General Service). The bill calculation shown in Detailed Calculations – Newmarket represents the monthly bill for a typical single light. Distribution Rates were heavily impacted with The Applicant's 2008 Application and receives a minor adjustment here. Fixed and Variable Distribution charges increase by 6.8%, but are largely offset by the following reductions leaving a total bill increase of 2.7%:

- Reduction of the Deferral Account Recovery Rate
- Reduction of Total Loss Factor

Sentinel Lights - Tay

Sentinel Lights are typically anywhere from one to a few lights that are billed in conjunction with another account (usually General Service). The bill calculation shown in Detailed Bill Calculations – Tay represents the monthly bill for a typical single light. This Application represents the first adjustment that is supported by the Cost Allocation Model. As a result, the increase is more severe here than in the Newmarket Service area, but brings the total to an acceptable Cost/Revenue Ratio in one step. Fixed and Variable Distribution charges increase by 180.9%, but are largely offset by the following reductions leaving a total bill increase of 10.04%:

- Reduction of the Deferral Account Recovery Rate
- Reduction of Total Loss Factor

Detailed Bill Calculations

The following tables provide a comparison by class for customers at various level of consumption as specified in OEB Appendix 2.4. All calculations exclude taxes, and rates over which The Applicant has no control, are kept at the 2009 level.

Newmarket

Residential

	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Consumption	**100**							
Monthly Service Charge			13.44			17.00	3.56	26.49%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	100	0.01360	1.36	100	0.01432	1.43	0.07	5.27%
Deferred Account Recovery & LV Adder	100	0.00250	0.25	100	0.00237	0.24	(0.01)	-5.22%
Sub-Total			**15.66**			**18.67**	**3.01**	**19.21%**
Debt Retirement Charge	100	0.00700	0.70	100	0.00700	0.70	0.00	0.00%
Wholesale Market Services	104	0.00520	0.54	104	0.00520	0.54	(0.00)	-0.09%
Rural Rate Assistance	104	0.00130	0.13	104	0.00130	0.13	(0.00)	-0.09%
Transmission Network	104	0.00540	0.56	104	0.00675	0.70	0.14	24.81%
Transmission Connection	104	0.00480	0.50	104	0.00511	0.53	0.03	6.46%
Cost of Power Commodity <600 kWh	104	0.05700	5.91	104	0.05700	5.90	(0.01)	-0.09%
Cost of Power Commodity >600 kWh	0	0.06600	0.00	0	0.06600	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**24.25**			**27.42**	**3.17**	**13.09%**

Residential Consumption	**250**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			13.44			17.00	3.56	26.49%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	250	0.01360	3.40	250	0.01432	3.58	0.18	5.27%
Deferred Account Recovery & LV Adder	250	0.00250	0.63	250	0.00237	0.59	(0.03)	-5.22%
Sub-Total			**18.08**			**21.17**	**3.10**	**17.13%**
Debt Retirement Charge	250	0.00700	1.75	250	0.00700	1.75	0.00	0.00%
Wholesale Market Services	259	0.00520	1.35	259	0.00520	1.35	(0.00)	-0.09%
Rural Rate Assistance	259	0.00130	0.34	259	0.00130	0.34	(0.00)	-0.09%
Transmission Network	259	0.00540	1.40	259	0.00675	1.75	0.35	24.81%
Transmission Connection	259	0.00480	1.24	259	0.00511	1.32	0.08	6.46%
Cost of Power Commodity <600 kWh	259	0.05700	14.77	259	0.05700	14.76	(0.01)	-0.09%
Cost of Power Commodity >600 kWh	0	0.06600	0.00	0	0.06600	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**39.17**			**42.68**	**3.51**	**8.96%**

Consumption	**500**							
Monthly Service Charge			13.44			17.00	3.56	26.49%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	500	0.01360	6.80	500	0.01432	7.16	0.36	5.27%
Deferred Account Recovery & LV Adder	500	0.00250	1.25	500	0.00237	1.18	(0.07)	-5.22%
Sub-Total			**22.10**			**25.34**	**3.24**	**14.68%**
Debt Retirement Charge	500	0.00700	3.50	500	0.00700	3.50	0.00	0.00%
Wholesale Market Services	518	0.00520	2.69	518	0.00520	2.69	(0.00)	-0.09%
Rural Rate Assistance	518	0.00130	0.67	518	0.00130	0.67	(0.00)	-0.09%
Transmission Network	518	0.00540	2.80	518	0.00675	3.49	0.69	24.81%
Transmission Connection	518	0.00480	2.49	518	0.00511	2.65	0.16	6.46%
Cost of Power Commodity <600 kWh	518	0.05700	29.54	518	0.05700	29.51	(0.03)	-0.09%
Cost of Power Commodity >600 kWh	0	0.06600	0.00	0	0.06600	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**64.05**			**68.11**	**4.07**	**6.35%**

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NEWMARKET

Residential Consumption	**800**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			13.44			17.00	3.56	26.49%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	800	0.01360	10.88	800	0.01432	11.45	0.57	5.27%
Deferred Account Recovery & LV Adder	800	0.00250	2.00	800	0.00237	1.90	(0.10)	-5.22%
Sub-Total			**26.93**			**30.35**	**3.42**	**12.70%**
Debt Retirement Charge	800	0.00700	5.60	800	0.00700	5.60	0.00	0.00%
Wholesale Market Services	829	0.00520	4.31	828	0.00520	4.31	(0.00)	-0.09%
Rural Rate Assistance	829	0.00130	1.08	828	0.00130	1.08	(0.00)	-0.09%
Transmission Network	829	0.00540	4.48	828	0.00675	5.59	1.11	24.81%
Transmission Connection	829	0.00480	3.98	828	0.00511	4.24	0.26	6.46%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	229	0.06600	15.13	228	0.06600	15.08	(0.05)	-0.32%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**95.95**			**100.69**	**4.73**	**4.93%**

Consumption	**1,000**							
Monthly Service Charge			13.44			17.00	3.56	26.49%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	1,000	0.01360	13.60	1,000	0.01432	14.32	0.72	5.27%
Deferred Account Recovery & LV Adder	1,000	0.00250	2.50	1,000	0.00237	2.37	(0.13)	-5.22%
Sub-Total			**30.15**			**33.69**	**3.54**	**11.73%**
Debt Retirement Charge	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.00%
Wholesale Market Services	1,037	0.00520	5.39	1,036	0.00520	5.38	(0.00)	-0.09%
Rural Rate Assistance	1,037	0.00130	1.35	1,036	0.00130	1.35	(0.00)	-0.09%
Transmission Network	1,037	0.00540	5.60	1,036	0.00675	6.99	1.39	24.81%
Transmission Connection	1,037	0.00480	4.98	1,036	0.00511	5.30	0.32	6.46%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	437	0.06600	28.81	436	0.06600	28.75	(0.06)	-0.21%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**117.72**			**122.90**	**5.18**	**4.40%**

NEWMARKET

Residential Consumption	**1,500**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			13.44			17.00	3.56	26.49%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	1,500	0.01360	20.40	1,500	0.01432	21.48	1.08	5.27%
Deferred Account Recovery & LV Adder	1,500	0.00250	3.75	1,500	0.00237	3.55	(0.20)	-5.22%
Sub-Total			**38.20**			**42.03**	**3.83**	**10.03%**
Debt Retirement Charge	1,500	0.00700	10.50	1,500	0.00700	10.50	0.00	0.00%
Wholesale Market Services	1,555	0.00520	8.08	1,553	0.00520	8.08	(0.01)	-0.09%
Rural Rate Assistance	1,555	0.00130	2.02	1,553	0.00130	2.02	(0.00)	-0.09%
Transmission Network	1,555	0.00540	8.40	1,553	0.00675	10.48	2.08	24.81%
Transmission Connection	1,555	0.00480	7.46	1,553	0.00511	7.94	0.48	6.46%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	955	0.06600	63.01	953	0.06600	62.92	(0.09)	-0.15%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**172.13**			**178.42**	**6.29**	**3.66%**

Consumption	**2,000**							
Monthly Service Charge			13.44			17.00	3.56	26.49%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	2,000	0.01360	27.20	2,000	0.01432	28.63	1.43	5.27%
Deferred Account Recovery & LV Adder	2,000	0.00250	5.00	2,000	0.00237	4.74	(0.26)	-5.22%
Sub-Total			**46.25**			**50.37**	**4.12**	**8.92%**
Debt Retirement Charge	2,000	0.00700	14.00	2,000	0.00700	14.00	0.00	0.00%
Wholesale Market Services	2,073	0.00520	10.78	2,071	0.00520	10.77	(0.01)	-0.09%
Rural Rate Assistance	2,073	0.00130	2.69	2,071	0.00130	2.69	(0.00)	-0.09%
Transmission Network	2,073	0.00540	11.19	2,071	0.00675	13.97	2.78	24.81%
Transmission Connection	2,073	0.00480	9.95	2,071	0.00511	10.59	0.64	6.46%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	1,473	0.06600	97.22	1,471	0.06600	97.10	(0.12)	-0.13%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**226.54**			**233.95**	**7.41**	**3.27%**

GS<50 kW

NEWMARKET

NEWMARKET GS<50 kW	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Consumption	**1,000**							
Monthly Service Charge			25.18			33.00	7.82	31.06%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	1,000	0.0159	15.90	1,000	0.0172	17.16	1.26	7.93%
Deferred Account Recovery & LV Adder	1,000	0.0012	1.20	1,000	0.0018	1.81	0.61	51.16%
Sub-Total			**42.89**			**51.97**	**9.08**	**21.18%**
Debt Retirement Charge	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.00%
Wholesale Market Services	1,037	0.0052	5.39	1,036	0.0052	5.38	(0.00)	-0.09%
Rural Rate Assistance	1,037	0.0013	1.35	1,036	0.0013	1.35	(0.00)	-0.09%
Transmission Network	1,037	0.0049	5.08	1,036	0.0061	6.35	1.27	24.94%
Transmission Connection	1,037	0.0043	4.46	1,036	0.0046	4.75	0.29	6.58%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	287	0.0660	18.91	286	0.0660	18.85	(0.06)	-0.32%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**128.07**			**138.65**	**10.58**	**8.26%**

NEWMARKET

GS<50 Consumption	**2,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			25.18			33.00	7.82	31.06%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	2,000	0.0159	31.80	2,000	0.0172	34.32	2.52	7.93%
Deferred Account Recovery & LV Adder	2,000	0.0012	2.40	2,000	0.0018	3.63	1.23	51.16%
Sub-Total			**59.99**			**70.95**	**10.96**	**18.27%**
Debt Retirement Charge	2,000	0.0070	14.00	2,000	0.0070	14.00	0.00	0.00%
Wholesale Market Services	2,073	0.0052	10.78	2,071	0.0052	10.77	(0.01)	-0.09%
Rural Rate Assistance	2,073	0.0013	2.69	2,071	0.0013	2.69	(0.00)	-0.09%
Transmission Network	2,073	0.0049	10.16	2,071	0.0061	12.69	2.53	24.94%
Transmission Connection	2,073	0.0043	8.91	2,071	0.0046	9.50	0.59	6.58%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	1,323	0.0660	87.32	1,321	0.0660	87.20	(0.12)	-0.14%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**236.85**			**250.80**	**13.95**	**5.89%**

Consumption	**5,000**							
Monthly Service Charge			25.18			33.00	7.82	31.06%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	5,000	0.0159	79.50	5,000	0.0172	85.80	6.30	7.93%
Deferred Account Recovery & LV Adder	5,000	0.0012	6.00	5,000	0.0018	9.07	3.07	51.16%
Sub-Total			**111.29**			**127.87**	**16.58**	**14.90%**
Debt Retirement Charge	5,000	0.0070	35.00	5,000	0.0070	35.00	0.00	0.00%
Wholesale Market Services	5,183	0.0052	26.95	5,178	0.0052	26.92	(0.02)	-0.09%
Rural Rate Assistance	5,183	0.0013	6.74	5,178	0.0013	6.73	(0.01)	-0.09%
Transmission Network	5,183	0.0049	25.39	5,178	0.0061	31.73	6.33	24.94%
Transmission Connection	5,183	0.0043	22.28	5,178	0.0046	23.75	1.47	6.58%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	4,433	0.0660	292.55	4,428	0.0660	292.24	(0.31)	-0.10%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**563.20**			**587.25**	**24.05**	**4.27%**

NEWMARKET

GS< 50 Consumption	**10,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			25.18			33.00	7.82	31.06%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	10,000	0.0159	159.00	10,000	0.0172	171.61	12.61	7.93%
Deferred Account Recovery & LV Adder	10,000	0.0012	12.00	10,000	0.0018	18.14	6.14	51.16%
Sub-Total			**196.79**			**222.75**	**25.96**	**13.19%**
Debt Retirement Charge	10,000	0.0070	70.00	10,000	0.0070	70.00	0.00	0.00%
Wholesale Market Services	10,365	0.0052	53.90	10,356	0.0052	53.85	(0.05)	-0.09%
Rural Rate Assistance	10,365	0.0013	13.47	10,356	0.0013	13.46	(0.01)	-0.09%
Transmission Network	10,365	0.0049	50.79	10,356	0.0061	63.45	12.67	24.94%
Transmission Connection	10,365	0.0043	44.57	10,356	0.0046	47.50	2.93	6.58%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	9,615	0.0660	634.59	9,606	0.0660	633.98	(0.61)	-0.10%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**1,107.11**			**1,148.00**	**40.89**	**3.69%**

Consumption	**15,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			25.18			33.00	7.82	31.06%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	15,000	0.0159	238.50	15,000	0.0172	257.41	18.91	7.93%
Deferred Account Recovery & LV Adder	15,000	0.0012	18.00	15,000	0.0018	27.21	9.21	51.16%
Sub-Total			**282.29**			**317.62**	**35.33**	**12.52%**
Debt Retirement Charge	15,000	0.0070	105.00	15,000	0.0070	105.00	0.00	0.00%
Wholesale Market Services	15,548	0.0052	80.85	15,534	0.0052	80.77	(0.07)	-0.09%
Rural Rate Assistance	15,548	0.0013	20.21	15,534	0.0013	20.19	(0.02)	-0.09%
Transmission Network	15,548	0.0049	76.18	15,534	0.0061	95.18	19.00	24.94%
Transmission Connection	15,548	0.0043	66.85	15,534	0.0046	71.26	4.40	6.58%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	14,798	0.0660	976.64	14,784	0.0660	975.72	(0.92)	-0.09%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**1,651.02**			**1,708.75**	**57.73**	**3.50%**

NEWMARKET
Unmetered Scattered Load

	2009 BILL			2010 BILL			IMPACT	
	Volume	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**Change $**	**Change %**
Consumption	**200**							
Monthly Service Charge			16.39			12.00	(4.39)	-26.78%
Distribution	200	0.0159	3.18	200	0.0172	3.43	0.25	7.93%
Deferred Account Recovery & LV Adder	200	0.0012	0.24	200	0.0007	0.15	(0.09)	-38.71%
Sub-Total			**19.81**			**15.58**	**(4.23)**	**-21.36%**
Debt Retirement Charge	200	0.0070	1.40	200	0.0070	1.40	0.00	0.00%
Wholesale Market Services	207	0.0052	1.08	207	0.0052	1.08	(0.00)	-0.09%
Rural Rate Assistance	207	0.0013	0.27	207	0.0013	0.27	(0.00)	-0.09%
Transmission Network	207	0.0049	1.02	207	0.0061	1.26	0.24	23.91%
Transmission Connection	207	0.0043	0.89	207	0.0045	0.94	0.05	5.58%
Cost of Power Commodity <600 kWh	207	0.0570	11.82	207	0.0570	11.81	(0.01)	-0.09%
	0	0.0660	0.00	0	0.0660	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**36.53**			**32.58**	**(3.95)**	**-10.81%**

Consumption	**500**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			16.39			12.00	(4.39)	-26.78%
Distribution	500	0.0159	7.95	500	0.0172	8.58	0.63	7.93%
Deferred Account Recovery & LV Adder	500	0.0012	0.60	500	0.0007	0.37	(0.23)	-38.71%
Sub-Total			**24.94**			**20.95**	**(3.99)**	**-16.01%**
Debt Retirement Charge	500	0.0070	3.50	500	0.0070	3.50	0.00	0.00%
Wholesale Market Services	518	0.0052	2.69	518	0.0052	2.69	(0.00)	-0.09%
Rural Rate Assistance	518	0.0013	0.67	518	0.0013	0.67	(0.00)	-0.09%
Transmission Network	518	0.0049	2.54	518	0.0061	3.15	0.61	23.91%
Transmission Connection	518	0.0043	2.23	518	0.0045	2.35	0.12	5.58%
Cost of Power Commodity <600 kWh	518	0.0570	29.54	518	0.0570	29.51	(0.03)	-0.09%
	0	0.0660	0.00	0	0.0660	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**66.37**			**63.08**	**(3.29)**	**-4.96%**

GS>50 kW

Newmarket

GS>50 kW	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Consumption	**25,000**							
Demand	**60**							
Monthly Service Charge			157.04			150.00	(7.04)	-4.48%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution	60	4.3209	259.25	60	5.1840	311.04	51.78	19.97%
Deferred Account Recovery & LV Adder	60	0.1401	8.41	60	0.2118	12.71	4.30	51.19%
Sub-Total			**425.31**			**473.75**	**48.44**	**11.39%**
Wholesale Market Services	25,913	0.0052	134.75	25,889	0.0052	134.62	(0.12)	-0.09%
Rural Rate Assistance	25,913	0.0013	33.69	25,889	0.0013	33.66	(0.03)	-0.09%
Debt Retirement Charge	25,000	0.0070	175.00	25,000	0.0070	175.00	0.00	0.00%
Transmission Network/kW	60	1.9923	119.54	60	2.4937	149.62	30.09	25.17%
Transmission Connection	60	1.7038	102.23	60	1.8193	109.16	6.93	6.78%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	25,163	0.0660	1,660.73	25,139	0.0660	1,659.20	(1.53)	-0.09%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**2,694.23**			**2,778.01**	**83.78**	**3.11%**

1 Newmarket

GS> 50 Consumption	40,000	Rate	Charge	Volume	Rate	Charge $	Change $	Change %
Demand	100							
Monthly Service Charge			157.04			150.00	(7.04)	-4.48%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution (kW)	100	4.3209	432.09	100	5.1840	518.40	86.31	19.97%
Deferred Account Recovery (kW)	100	0.1401	14.01	100	0.2118	21.18	7.17	51.19%
Tranformer Allowance	100	-0.7000	-70.00	100	(0.7000)	(70.00)	0.00	0.00%
Sub-Total			**533.75**			**619.58**	**85.83**	**16.08%**
Wholesale Market Services	41,460	0.0052	215.59	41,423	0.0052	215.40	(0.19)	-0.09%
Rural Rate Assistance	41,460	0.0013	53.90	41,423	0.0013	53.85	(0.05)	-0.09%
Debt Retirement Charge	40,000	0.0070	280.00	40,000	0.0070	280.00	0.00	0.00%
Transmission Network/kW	100	1.9923	199.23	100	2.4937	249.37	50.14	25.17%
Transmission Connection	100	1.7038	170.38	100	1.8193	181.93	11.55	6.78%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	40,710	0.0660	2,686.86	40,673	0.0660	2,684.42	(2.44)	-0.09%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**4,182.71**			**4,327.55**	**144.84**	**3.46%**

2

Consumption	200,000	Rate	Charge	Volume	Rate	Charge $	Change $	Change %
Demand	500							
Monthly Service Charge			157.04			150.00	(7.04)	-4.48%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution (kW)	500	4.3209	2,160.45	500	5.1840	2,591.98	431.53	19.97%
Deferred Account Recovery (kW)	500	0.1401	70.05	500	0.2118	105.91	35.86	51.19%
Tranformer Allowance	500	(0.70)	(350.00)	500	(0.7000)	(350.00)	0.00	0.00%
Sub-Total			**2,038.15**			**2,497.89**	**459.74**	**22.56%**
Wholesale Market Services	207,300	0.0052	1,077.96	207,115	0.0052	1,077.00	(0.96)	-0.09%
Rural Rate Assistance	207,300	0.0013	269.49	207,115	0.0013	269.25	(0.24)	-0.09%
Debt Retirement Charge	200,000	0.0070	1,400.00	200,000	0.0070	1,400.00	0.00	0.00%
Transmission Network/kW	500	1.9923	996.15	500	2.4937	1,246.87	250.72	25.17%
Transmission Connection	500	1.7038	851.90	500	1.8193	909.67	57.77	6.78%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	206,550	0.0660	13,632.30	206,365	0.0660	13,620.10	(12.20)	-0.09%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**20,308.95**			**21,063.77**	**754.82**	**3.72%**

Newmarket

GS> 50 Consumption	**400,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Demand	**1,000**							
Monthly Service Charge			157.04			150.00	(7.04)	-4.48%
Smart Meter Adder			0.61			0.00	(0.61)	-100.00%
Distribution (kW)	1,000	4.3209	4,320.90	1,000	5.1840	5,183.96	863.06	19.97%
Deferred Account Recovery (kW)	1,000	0.1401	140.10	1,000	0.2118	211.81	71.71	51.19%
Tranformer Allowance	1,000	(0.70)	(700.00)	1,000	(0.7000)	(700.00)	0.00	0.00%
Sub-Total			**3,918.65**			**4,845.77**	**927.12**	**23.66%**
Wholesale Market Services	414,600	0.0052	2,155.92	414,230	0.0052	2,154.00	(1.92)	-0.09%
Rural Rate Assistance	414,600	0.0013	538.98	414,230	0.0013	538.50	(0.48)	-0.09%
Debt Retirement Charge	400,000	0.0070	2,800.00	400,000	0.0070	2,800.00	0.00	0.00%
Transmission Network/kW	1,000	1.9923	1,992.30	1,000	2.4937	2,493.75	501.45	25.17%
Transmission Connection	1,000	1.7038	1,703.80	1,000	1.8193	1,819.33	115.53	6.78%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	413,850	0.0660	27,314.10	413,480	0.0660	27,289.70	(24.40)	-0.09%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**40,466.75**			**41,984.05**	**1,517.30**	**3.75%**

Newmarket

Street Lights	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Monthly Service Charge	7,738	1.76	13,618.24	7,738	2.00	15,475.27	1,857.03	13.64%
Distribution	1,092	8.7325	9,538.80	1,092	7.5452	8,241.85	(1,296.95)	-13.60%
Deferred Account Recovery	1,092	0.1907	208.31	1,092	0.1683	183.82	(24.49)	-11.76%
Sub-Total			**23,365.34**			**23,900.94**	**535.59**	**2.29%**
Wholesale Market Services	417,039	0.0052	2,168.60	416,667	0.0052	2,166.67	(1.93)	-0.09%
Rural Rate Assistance	417,039	0.0013	542.15	416,667	0.0013	541.67	(0.48)	-0.09%
Debt Retirement Charge	402,353	0.0070	2,816.47	402,353	0.0070	2,816.47	0.00	0.00%
Transmission Network/kW	1,092	1.5025	1,641.23	1,092	1.8990	2,074.37	433.13	26.39%
Transmission Connection	1,092	1.3172	1,438.82	1,092	1.4049	1,534.63	95.81	6.66%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	416,289	0.0660	27,475.06	415,917	0.0660	27,450.52	(24.54)	-0.09%
Regulated Price Plan Admin	7,738	0.2500	1,934.41	7,738	0.2500	1,934.41	0.00	0.00%
Total Bill Before Tax			**61,424.84**			**62,462.41**	**1,037.57**	**1.69%**

Newmarket

Sentinel Lights	2009 BILL Volume	RATE $	CHARGE $	2010 BILL Volume	RATE $	CHARGE $	IMPACT Change $	Change %
Monthly Service Charge			2.00			2.00	0.00	0.00%
Distribution	0.2	6.7192	1.22	0.2	7.9298	1.44	0.22	18.02%
Deferred Account Recovery	0.2	0.5879	0.11	0.2	0.1822	0.03	(0.07)	-69.01%
Sub-Total			**3.33**			**3.48**	**0.15**	**4.40%**
Wholesale Market Services	62	0.0052	0.32	62	0.0052	0.32	(0.00)	-0.09%
Rural Rate Assistance	62	0.0013	0.08	62	0.0013	0.08	(0.00)	-0.09%
Debt Retirement Charge	60	0.0070	0.42	60	0.0070	0.42	0.00	0.00%
Transmission Network/kW	0.2	1.5101	0.27	0.2	1.8829	0.34	0.07	24.68%
Transmission Connection	0.2	1.3447	0.24	0.2	1.4356	0.26	0.02	6.76%
Cost of Power Commodity <750 kWh	62	0.0570	3.54	62	0.0570	3.54	0.00	0.00%
Cost of Power Commodity >750 kWh	0.0	0.0660	0.00	0.0	0.0660	0.00	0.00	0.00%
Regulated Price Plan Admin	1	0.2500	0.25	1	0.2500	0.25	0.00	0.00%
Total Bill Before Tax			**8.46**			**8.69**	**0.23**	**2.72%**

Tay

Residential

	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Consumption	**100**							
Monthly Service Charge			14.59			17.00	2.41	16.52%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	100	0.0101	1.01	100	0.0143	1.43	0.42	41.76%
Deferred Account Recovery & LV Adder	100	0.0070	0.70	100	0.0024	0.24	(0.47)	-66.34%
Sub-Total			**18.89**			**18.67**	**(0.23)**	**-1.19%**
Debt Retirement Charge	100	0.0070	0.70	100	0.0070	0.70	0.00	0.00%
Wholesale Market Services	109	0.0052	0.57	104	0.0052	0.54	(0.03)	-4.70%
Rural Rate Assistance	109	0.0010	0.11	104	0.0013	0.13	0.03	23.90%
Transmission Network	109	0.0053	0.58	104	0.0067	0.70	0.12	21.30%
Transmission Connection	109	0.0047	0.51	104	0.0051	0.53	0.02	3.71%
Cost of Power Commodity <600 kWh	109	0.0570	6.19	104	0.0570	5.90	(0.29)	-4.70%
Cost of Power Commodity >600 kWh	0	0.0660	0.00	0	0.0660	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**27.80**			**27.42**	**(0.38)**	**-1.35%**

1 TAY

Residential Consumption	**250**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.59			17.00	2.41	16.52%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	250	0.0101	2.53	250	0.0143	3.58	1.05	41.76%
Deferred Account Recovery & LV Adder	250	0.0070	1.76	250	0.0024	0.59	(1.17)	-66.34%
Sub-Total			**21.47**			**21.17**	**(0.29)**	**-1.37%**
Debt Retirement Charge	250	0.0070	1.75	250	0.0070	1.75	0.00	0.00%
Wholesale Market Services	272	0.0052	1.41	259	0.0052	1.35	(0.07)	-4.70%
Rural Rate Assistance	272	0.0010	0.27	259	0.0013	0.34	0.06	23.90%
Transmission Network	272	0.0053	1.44	259	0.0067	1.75	0.31	21.30%
Transmission Connection	272	0.0047	1.28	259	0.0051	1.32	0.05	3.71%
Cost of Power Commodity <600 kWh	272	0.0570	15.48	259	0.0570	14.76	(0.73)	-4.70%
Cost of Power Commodity >600 kWh	0	0.0660	0.00	0	0.0660	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**43.35**			**42.68**	**(0.67)**	**-1.54%**

2

Residential Consumption	**500**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.59			17.00	2.41	16.52%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	500	0.0101	5.05	500	0.0143	7.16	2.11	41.76%
Deferred Account Recovery & LV Adder	500	0.0070	3.52	500	0.0024	1.18	(2.34)	-66.34%
Sub-Total			**25.75**			**25.34**	**(0.41)**	**-1.58%**
Debt Retirement Charge	500	0.0070	3.50	500	0.0070	3.50	0.00	0.00%
Wholesale Market Services	543	0.0052	2.83	518	0.0052	2.69	(0.13)	-4.70%
Rural Rate Assistance	543	0.0010	0.54	518	0.0013	0.67	0.13	23.90%
Transmission Network	543	0.0053	2.88	518	0.0067	3.49	0.61	21.30%
Transmission Connection	543	0.0047	2.55	518	0.0051	2.65	0.09	3.71%
Cost of Power Commodity <600 kWh	543	0.0570	30.97	518	0.0570	29.51	(1.45)	-4.70%
Cost of Power Commodity >600 kWh	0	0.0660	0.00	0	0.0660	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**69.27**			**68.11**	**(1.16)**	**-1.67%**

Tay

Residential Consumption	**800**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.59			17.00	2.41	16.52%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	800	0.01010	8.08	800	0.01432	11.45	3.37	41.76%
Deferred Account Recovery & LV Adder	800	0.00704	5.63	800	0.00237	1.90	(3.74)	-66.34%
Sub-Total			**30.89**			**30.35**	**(0.54)**	**-1.76%**
Debt Retirement Charge	800	0.00700	5.60	800	0.00700	5.60	0.00	0.00%
Wholesale Market Services	869	0.00520	4.52	828	0.00520	4.31	(0.21)	-4.70%
Rural Rate Assistance	869	0.00100	0.87	828	0.00130	1.08	0.21	23.90%
Transmission Network	869	0.00530	4.61	828	0.00675	5.59	0.98	21.30%
Transmission Connection	869	0.00470	4.09	828	0.00511	4.24	0.15	3.71%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	269	0.06600	17.77	228	0.06600	15.08	(2.69)	-15.16%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**102.80**			**100.69**	**(2.11)**	**-2.05%**

Residential Consumption	**1,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.59			17.00	2.41	16.52%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	1,000	0.01010	10.10	1,000	0.01432	14.32	4.22	41.76%
Deferred Account Recovery & LV Adder	1,000	0.00704	7.04	1,000	0.00237	2.37	(4.67)	-66.34%
Sub-Total			**34.32**			**33.69**	**(0.63)**	**-1.85%**
Debt Retirement Charge	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.00%
Wholesale Market Services	1,087	0.00520	5.65	1,036	0.00520	5.38	(0.27)	-4.70%
Rural Rate Assistance	1,087	0.00100	1.09	1,036	0.00130	1.35	0.26	23.90%
Transmission Network	1,087	0.00530	5.76	1,036	0.00675	6.99	1.23	21.30%
Transmission Connection	1,087	0.00470	5.11	1,036	0.00511	5.30	0.19	3.71%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	487	0.06600	32.12	436	0.06600	28.75	(3.37)	-10.49%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**125.49**			**122.90**	**(2.59)**	**-2.06%**

Tay

Residential Consumption	**1,500**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.59			17.00	2.41	16.52%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	1,500	0.01010	15.15	1,500	0.01432	21.48	6.33	41.76%
Deferred Account Recovery & LV Adder	1,500	0.00704	10.56	1,500	0.00237	3.55	(7.01)	-66.34%
Sub-Total			**42.89**			**42.03**	**(0.86)**	**-2.00%**
Debt Retirement Charge	1,500	0.00700	10.50	1,500	0.00700	10.50	0.00	0.00%
Wholesale Market Services	1,630	0.00520	8.48	1,553	0.00520	8.08	(0.40)	-4.70%
Rural Rate Assistance	1,630	0.00100	1.63	1,553	0.00130	2.02	0.39	23.90%
Transmission Network	1,630	0.00530	8.64	1,553	0.00675	10.48	1.84	21.30%
Transmission Connection	1,630	0.00470	7.66	1,553	0.00511	7.94	0.28	3.71%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	1,030	0.06600	67.97	953	0.06600	62.92	(5.05)	-7.43%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**182.22**			**178.42**	**(3.80)**	**-2.08%**

Residential Consumption	**2,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.59			17.00	2.41	16.52%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	2,000	0.01010	20.20	2,000	0.01432	28.63	8.43	41.76%
Deferred Account Recovery & LV Adder	2,000	0.00704	14.08	2,000	0.00237	4.74	(9.34)	-66.34%
Sub-Total			**51.46**			**50.37**	**(1.09)**	**-2.11%**
Debt Retirement Charge	2,000	0.00700	14.00	2,000	0.00700	14.00	0.00	0.00%
Wholesale Market Services	2,173	0.00520	11.30	2,071	0.00520	10.77	(0.53)	-4.70%
Rural Rate Assistance	2,173	0.00100	2.17	2,071	0.00130	2.69	0.52	23.90%
Transmission Network	2,173	0.00530	11.52	2,071	0.00675	13.97	2.45	21.30%
Transmission Connection	2,173	0.00470	10.21	2,071	0.00511	10.59	0.38	3.71%
Cost of Power Commodity <600 kWh	600	0.05700	34.20	600	0.05700	34.20	0.00	0.00%
Cost of Power Commodity >600 kWh	1,573	0.06600	103.83	1,471	0.06600	97.10	(6.74)	-6.49%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**238.95**			**233.95**	**(5.00)**	**-2.09%**

Tay

GS<50 kW

	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Consumption	**1,000**							
Monthly Service Charge			14.72			33.00	18.28	124.18%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	1,000	0.0165	16.46	1,000	0.0172	17.16	0.70	4.26%
Deferred Account Recovery & LV Adder	1,000	0.0051	5.14	1,000	0.0018	1.81	(3.33)	-64.71%
Sub-Total			**38.91**			**51.97**	**13.06**	**33.58%**
Debt Retirement Charge	1,000	0.0070	7.00	1,000	0.0070	7.00	0.00	0.00%
Wholesale Market Services	1,087	0.0052	5.65	1,036	0.0052	5.38	(0.27)	-4.70%
Rural Rate Assistance	1,087	0.0010	1.09	1,036	0.0013	1.35	0.26	23.90%
Transmission Network	1,087	0.0048	5.22	1,036	0.0061	6.35	1.13	21.66%
Transmission Connection	1,087	0.0042	4.56	1,036	0.0046	4.75	0.19	4.09%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	337	0.0660	22.22	286	0.0660	18.85	(3.37)	-15.16%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**127.64**			**138.65**	**11.01**	**8.62%**

Tay

GS< 50 Consumption	2,000	Rate	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.72			33.00	18.28	124.18%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	2,000	0.0165	32.92	2,000	0.0172	34.32	1.40	4.26%
Deferred Account Recovery & LV Adder	2,000	0.0051	10.28	2,000	0.0018	3.63	(6.65)	-64.71%
Sub-Total			**60.51**			**70.95**	**10.44**	**17.25%**
Debt Retirement Charge	2,000	0.0070	14.00	2,000	0.0070	14.00	0.00	0.00%
Wholesale Market Services	2,173	0.0052	11.30	2,071	0.0052	10.77	(0.53)	-4.70%
Rural Rate Assistance	2,173	0.0010	2.17	2,071	0.0013	2.69	0.52	23.90%
Transmission Network	2,173	0.0048	10.43	2,071	0.0061	12.69	2.26	21.66%
Transmission Connection	2,173	0.0042	9.13	2,071	0.0046	9.50	0.37	4.09%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	1,423	0.0660	93.93	1,321	0.0660	87.20	(6.74)	-7.17%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**244.47**			**250.80**	**6.33**	**2.59%**

GS< 50 Consumption	5,000	Rate	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.72			33.00	18.28	124.18%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	5,000	0.0165	82.30	5,000	0.0172	85.80	3.50	4.26%
Deferred Account Recovery & LV Adder	5,000	0.0051	25.70	5,000	0.0018	9.07	(16.63)	-64.71%
Sub-Total			**125.31**			**127.87**	**2.56**	**2.05%**
Debt Retirement Charge	5,000	0.0070	35.00	5,000	0.0070	35.00	0.00	0.00%
Wholesale Market Services	5,433	0.0052	28.25	5,178	0.0052	26.92	(1.33)	-4.70%
Rural Rate Assistance	5,433	0.0010	5.43	5,178	0.0013	6.73	1.30	23.90%
Transmission Network	5,433	0.0048	26.08	5,178	0.0061	31.73	5.65	21.66%
Transmission Connection	5,433	0.0042	22.82	5,178	0.0046	23.75	0.93	4.09%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	4,683	0.0660	309.08	4,428	0.0660	292.24	(16.84)	-5.45%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**594.97**			**587.25**	**(7.72)**	**-1.30%**

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GS< 50 Consumption	10,000	Rate	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.72			33.00	18.28	124.18%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	10,000	0.0165	164.60	10,000	0.0172	171.61	7.01	4.26%
Deferred Account Recovery & LV Adder	10,000	0.0051	51.40	10,000	0.0018	18.14	(33.26)	-64.71%
Sub-Total			**233.31**			**222.75**	**(10.56)**	**-4.53%**
Debt Retirement Charge	10,000	0.0070	70.00	10,000	0.0070	70.00	0.00	0.00%
Wholesale Market Services	10,866	0.0052	56.50	10,356	0.0052	53.85	(2.65)	-4.70%
Rural Rate Assistance	10,866	0.0010	10.87	10,356	0.0013	13.46	2.60	23.90%
Transmission Network	10,866	0.0048	52.16	10,356	0.0061	63.45	11.30	21.66%
Transmission Connection	10,866	0.0042	45.64	10,356	0.0046	47.50	1.87	4.09%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	10,116	0.0660	667.66	9,606	0.0660	633.98	(33.68)	-5.04%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**1,179.13**			**1,148.00**	**(31.13)**	**-2.64%**

GS< 50 Consumption	15,000	Rate	Charge	Volume	Rate	Charge $	Change $	Change %
Monthly Service Charge			14.72			33.00	18.28	124.18%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	15,000	0.0165	246.90	15,000	0.0172	257.41	10.51	4.26%
Deferred Account Recovery & LV Adder	15,000	0.0051	77.10	15,000	0.0018	27.21	(49.89)	-64.71%
Sub-Total			**341.31**			**317.62**	**(23.69)**	**-6.94%**
Debt Retirement Charge	15,000	0.0070	105.00	15,000	0.0070	105.00	0.00	0.00%
Wholesale Market Services	16,299	0.0052	84.75	15,534	0.0052	80.77	(3.98)	-4.70%
Rural Rate Assistance	16,299	0.0010	16.30	15,534	0.0013	20.19	3.89	23.90%
Transmission Network	16,299	0.0048	78.24	15,534	0.0061	95.18	16.95	21.66%
Transmission Connection	16,299	0.0042	68.46	15,534	0.0046	71.26	2.80	4.09%
Cost of Power Commodity <600 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >600 kWh	15,549	0.0660	1,026.23	14,784	0.0660	975.72	(50.51)	-4.92%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**1,763.29**			**1,708.75**	**(54.54)**	**-3.09%**

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Unmetered Scattered Load	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Consumption	**200**							
Monthly Service Charge			7.35			12.00	4.65	63.27%
Distribution	200	0.0165	3.29	200	0.0172	3.43	0.14	4.32%
Deferred Account Recovery & LV Adder	200	0.0091	1.83	200	0.0007	0.15	(1.68)	- 91.95%
Sub-Total			**12.47**			**15.58**	**3.11**	**24.95%**
Debt Retirement Charge	200	0.0070	1.40	200	0.0070	1.40	0.00	0.00%
Wholesale Market Services	217	0.0052	1.13	207	0.0052	1.08	(0.05)	-4.70%
Rural Rate Assistance	217	0.0010	0.22	207	0.0013	0.27	0.05	23.90%
Transmission Network	217	0.0048	1.04	207	0.0061	1.26	0.22	20.66%
Transmission Connection	217	0.0042	0.91	207	0.0045	0.94	0.03	3.11%
Cost of Power Commodity <600 kWh	217	0.0570	12.39	207	0.0570	11.81	(0.58)	-4.70%
	0	0.0660	0.00	0	0.0660	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**29.81**			**32.58**	**2.77**	**9.30%**

Unmetered Scattered Load	2009 Volume	2009 RATE $	2009 CHARGE $	2010 Volume	2010 RATE $	2010 CHARGE $	Change $	Change %
Consumption	**500**							
Monthly Service Charge			7.35			12.00	4.65	63.27%
Distribution	500	0.0165	8.23	500	0.0172	8.58	0.36	4.32%
Deferred Account Recovery & LV Adder	500	0.0091	4.57	500	0.0007	0.37	(4.20)	- 91.95%
Sub-Total			**20.15**			**20.95**	**0.80**	**3.99%**
Debt Retirement Charge	500	0.0070	3.50	500	0.0070	3.50	0.00	0.00%
Wholesale Market Services	543	0.0052	2.83	518	0.0052	2.69	(0.13)	-4.70%
Rural Rate Assistance	543	0.0010	0.54	518	0.0013	0.67	0.13	23.90%
Transmission Network	543	0.0048	2.61	518	0.0061	3.15	0.54	20.66%
Transmission Connection	543	0.0042	2.28	518	0.0045	2.35	0.07	3.11%
Cost of Power Commodity <600 kWh	543	0.0570	30.97	518	0.0570	29.51	(1.45)	-4.70%
	0	0.0660	0.00	0	0.0660	0.00	0.00	0.00%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**63.12**			**63.08**	**(0.04)**	**-0.07%**

Tay

GS>50 kW	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Consumption	**25,000**							
Demand	**60**							
Monthly Service Charge			208.38			150.00	(58.38)	-28.02%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution	60	2.7726	166.36	60	5.1840	311.04	144.68	86.97%
Deferred Account Recovery & LV Adder	60	1.4716	88.30	60	0.2118	12.71	(75.59)	-85.61%
Sub-Total			**465.62**			**473.75**	**8.12**	**1.74%**
Wholesale Market Services	27,165	0.0052	141.26	25,889	0.0052	134.62	(6.63)	-4.70%
Rural Rate Assistance	27,165	0.0010	27.17	25,889	0.0013	33.66	6.49	23.90%
Debt Retirement Charge	25,000	0.0070	175.00	25,000	0.0070	175.00	0.00	0.00%
Transmission Network/kW	60	1.9747	118.48	60	2.4937	149.62	31.14	26.28%
Transmission Connection	60	1.6747	100.48	60	1.8193	109.16	8.68	8.64%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	26,415	0.0660	1,743.39	25,139	0.0660	1,659.20	(84.19)	-4.83%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**2,814.40**			**2,778.01**	**(36.39)**	**-1.29%**

Tay

GS>50 Consumption	**40,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Demand	**100**							
Monthly Service Charge			208.38			150.00	(58.38)	-28.02%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution (kW)	100	2.7726	277.26	100	5.1840	518.40	241.14	86.97%
Deferred Account Recovery (kW)	100	1.4716	147.16	100	0.2118	21.18	(125.98)	-85.61%
Tranformer Allowance	100	(0.6000)	(60.00)	100	(0.7000)	(70.00)	(10.00)	-16.67%
Sub-Total			**575.39**			**619.58**	**44.19**	**7.68%**
Wholesale Market Services	43,464	0.0052	226.01	41,423	0.0052	215.40	(10.61)	-4.70%
Rural Rate Assistance	43,464	0.0010	43.46	41,423	0.0013	53.85	10.39	23.90%
Debt Retirement Charge	40,000	0.0070	280.00	40,000	0.0070	280.00	0.00	0.00%
Transmission Network/kW	100	1.9747	197.47	100	2.4937	249.37	51.90	26.28%
Transmission Connection	100	1.6747	167.47	100	1.8193	181.93	14.46	8.64%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	42,714	0.0660	2,819.12	40,673	0.0660	2,684.42	(134.70)	-4.78%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill w/o GST			**4,351.93**			**4,327.55**	**(24.38)**	**-0.56%**

GS> 50 Consumption	**200,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Demand	**500**							
Monthly Service Charge			208.38			150.00	(58.38)	-28.02%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution (kW)	500	2.7726	1,386.30	500	5.1840	2,591.98	1,205.68	86.97%
Deferred Account Recovery (kW)	500	1.4716	735.80	500	0.2118	105.91	(629.89)	-85.61%
Transformer Allowance	500	(0.6000)	(300.00)	500	(0.7000)	(350.00)	(50.00)	-16.67%
Sub-Total			**2,033.07**			**2,497.89**	**464.82**	**22.86%**
Wholesale Market Services	217,320	0.0052	1,130.06	207,115	0.0052	1,077.00	(53.07)	-4.70%
Rural Rate Assistance	217,320	0.0010	217.32	207,115	0.0013	269.25	51.93	23.90%
Debt Retirement Charge	200,000	0.0070	1,400.00	200,000	0.0070	1,400.00	0.00	0.00%
Transmission Network/kW	500	1.9747	987.35	500	2.4937	1,246.87	259.52	26.28%
Transmission Connection	500	1.6747	837.35	500	1.8193	909.67	72.32	8.64%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	216,570	0.0660	14,293.62	206,365	0.0660	13,620.10	(673.52)	-4.71%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**20,941.77**			**21,063.77**	**122.00**	**0.58%**

Tay

Consumption	**400,000**	**Rate**	Charge	Volume	Rate	Charge $	Change $	Change %
Demand	**1,000**							
Monthly Service Charge			208.38			150.00	(58.38)	-28.02%
Smart Meter Adder			2.59			0.00	(2.59)	-100.00%
Distribution (kW)	1,000	2.7726	2,772.60	1,000	5.1840	5,183.96	2,411.36	86.97%
Deferred Account Recovery (kW)	1,000	1.4716	1,471.60	1,000	0.2118	211.81	(1,259.79)	-85.61%
Transformer Allowance	1,000	(0.6000)	(600.00)	1,000	(0.7000)	(700.00)	(100.00)	-16.67%
Sub-Total			**3,855.17**			**4,845.77**	**990.60**	**25.70%**
Wholesale Market Services	434,640	0.0052	2,260.13	414,230	0.0052	2,154.00	(106.13)	-4.70%
Rural Rate Assistance	434,640	0.0010	434.64	414,230	0.0013	538.50	103.86	23.90%
Debt Retirement Charge	400,000	0.0070	2,800.00	400,000	0.0070	2,800.00	0.00	0.00%
Transmission Network/kW	1,000	1.9747	1,974.70	1,000	2.4937	2,493.75	519.05	26.28%
Transmission Connection	1,000	1.6747	1,674.70	1,000	1.8193	1,819.33	144.63	8.64%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	433,890	0.0660	28,636.74	413,480	0.0660	27,289.70	(1,347.04)	-4.70%
Regulated Price Plan Admin			0.25			0.25	0.00	0.00%
Total Bill Before Tax			**41,679.08**			**41,984.05**	**304.97**	**0.73%**

Tay

Street Lights	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Monthly Service Charge	716	0.69	493.73	716	2.00	1,431.09	937.36	189.86%
Distribution	104	3.3623	348.84	104	7.5452	782.81	433.97	124.41%
Deferred Account Recovery	104	1.0734	111.37	104	0.1683	17.46	(93.91)	-84.32%
Sub-Total			**953.93**			**2,231.36**	**1,277.43**	**133.91%**
Wholesale Market Services	40,422	0.0052	210.20	38,524	0.0052	200.33	(9.87)	-4.70%
Rural Rate Assistance	40,422	0.0010	40.42	38,524	0.0013	50.08	9.66	23.90%
Debt Retirement Charge	37,201	0.0070	260.41	37,201	0.0070	260.41	0.00	0.00%
Transmission Network/kW	104	1.4893	154.51	104	1.8990	197.02	42.51	27.51%
Transmission Connection	104	1.2946	134.31	104	1.4049	145.76	11.44	8.52%
Cost of Power Commodity <750 kWh	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%
Cost of Power Commodity >750 kWh	39,672	0.0660	2,618.37	37,774	0.0660	2,493.10	(125.28)	-4.78%
Regulated Price Plan Admin	716	0.2500	178.89	716	0.2500	178.89	0.00	0.00%
Total Bill Before Tax			**4,593.79**			**5,799.69**	**1,205.89**	**26.25%**

Tay

Sentinel Lights	2009 BILL			2010 BILL			IMPACT	
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %
Monthly Service Charge			0.72			2.00	1.28	177.78%
Distribution	0.2	2.7791	0.51	0.2	7.9298	1.44	0.94	185.34%
Deferred Account Recovery	0.2	7.4173	1.35	0.2	0.1822	0.03	(1.32)	-97.54%
Sub-Total			**2.57**			**3.48**	**0.90**	**34.99%**
Wholesale Market Services	65	0.0052	0.34	62	0.0052	0.32	(0.02)	-4.70%
Rural Rate Assistance	65	0.0010	0.07	62	0.0013	0.08	0.02	23.90%
Debt Retirement Charge	60	0.0070	0.42	60	0.0070	0.42	0.00	0.00%
Transmission Network/kW	0.2	1.4968	0.27	0.2	1.8829	0.34	0.07	25.79%
Transmission Connection	0.2	1.3217	0.24	0.2	1.4356	0.26	0.02	8.62%
Cost of Power Commodity <750 kWh	65	0.0570	3.71	65	0.0570	3.71	0.00	0.00%
Cost of Power Commodity >750 kWh	0	0.0660	0.00	-3.1	0.0660	(0.20)	(0.20)	0.00%
Regulated Price Plan Admin	1	0.2500	0.25	1	0.2500	0.25	0.00	0.00%
Total Bill Before Tax			**7.87**			**8.66**	**0.79**	**10.04%**

Exhibit 9:

DEFERRAL AND VARIANCE ACCOUNTS

Exhibit 9: Deferral And Variance Accounts

Tab 1 (of 3): Status of Deferral and Variance Accounts

DEFERRAL AND VARIANCE ACCOUNTS AND LOST REVENUE ADJUSTMENT MECHANISM (LRAM)

Summary and Overview

The Applicant seeks approval to recover the following deferral/variance account balances commencing May 1, 2009.

1508	Other Regulatory Assets
1518	Retail Cost Variance Account – Retail
1525	Miscellaneous Deferred Debits
1548	Retail Cost Variance Account – STR
1550	Low Voltage Variance Account
1555	Smart Meter Capital
1556	Smart Meter OM&A
1580	RSVA-Wholesale Market Service Charge
1582	RSVA-One-time Wholesale Market Service
1584	RSVA-Retail Transmission Network Charge
1586	RSVA-Retail Transmission Connection Charge
1588	RSVA-Power
1590	Recovery of Regulatory Asset Balance – pre-2008
1595	Recovery of Regulatory Asset Balance - 2008
xxxx	Lost Revenue Adjustment Mechanism

The Applicant underwent a Regulatory Review by Ontario Energy Board staff during 2007. Each deferral account was examined along with recording methods and calculations of Carrying Charges. All recommendations made by Board staff have been adopted and adjustments made to each of the accounts affected. A follow-up review was conducted in September of 2009 and a letter confirming compliance was issued by Board staff on November 3, 2009. The letter is attached as Exhibit 9, Tab 1, Schedule 1, Attachment 1.

Account balances are actual March 31, 2010 balances. Carrying Charges have only been applied to the principal balance in each account (i.e. not on carrying charges). None of the balances proposed for disposition have been included in any previous rate filing with the exception of the "Approved Regulatory Asset" accounts 1590 and 1595 which represent the un-collected (or over-collected) approved balances at the end of the period. The Board Continuity Schedule is included at Exhibit 9, Tab 1, Schedule 2, Attachment 1.

The Applicant received approval from the Ontario Energy Board on April 23, 2009 to recover 2008 balances for the Newmarket service area. Therefore, most of the 2008 balances relate to the Tay service area with the exception of PILS (approval is not requested for these balances at this time) and LRAM (data only became available in June 2009). Also, The Applicant has calculated the Smart Meter Capital balances for both service areas following the guideline provided by the Ontario Energy Board "G-2008-0002 Guideline – Smart Meter Funding and Cost Recovery" and requests the recovery of these balances. This Guideline was not available when the 2008 Rate Submission was made. The detailed calculations are provided later in this exhibit.

The Applicant has chosen the "Cash Basis" of calculating Carrying Charges and uses the quarterly interest rates as prescribed by the OEB

DEFERRAL AND VARIANCE ACCOUNT BALANCES

As previously mentioned, The Applicant is requesting recovery of balances as at March 31, 2010. The balances on the following table are as submitted with the first quarter RRR filing with the exception of the Smart Meter accounts 1555 – Smart Meter Capital and 1556 – Smart Meter Operation and Maintenance. These accounts are covered in detail in Exhibit 9, Tab 4.

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
Other Regulatory Assets	1508	0	45,025	45,025	45,025	45,025
Carrying Charges		(0)	6,282	6,282	6,794	6,856
Other Regulatory Assets	**1508**	**(0)**	**51,306**	**51,306**	**51,819**	**51,880**
Retail Cost Variance - Retail	1518	0	(943)	(943)	(688)	(499)
Carrying Charges		0	(103)	(103)	(111)	(112)
Retail Cost Variance - Retail	**1518**	**0**	**(1,046)**	**(1,046)**	**(799)**	**(611)**
Misc Deferred Debits	1525	0	2,171	2,171	2,174	2,174
Carrying Charges		0	156	156	180	183
Misc Deferred Debits	**1525**	**0**	**2,326**	**2,326**	**2,354**	**2,357**
Retail Cost Variance - STR	1548	0	1,280	1,280	9,270	12,244
Carrying Charges		0	94	94	136	151
Retail Cost Variance - STR	**1548**	**0**	**1,374**	**1,374**	**9,406**	**12,395**
Low Voltage Variance	1550	0	(3,684)	(3,684)	(16,716)	(40,592)
Carrying Charges		0	255	255	154	113
Low Voltage Variance	**1550**	**0**	**(3,429)**	**(3,429)**	**(16,562)**	**(40,478)**
Smart Meter - Capital	1555	523,438	(139,434)	384,003	305,413	235,886
Carrying Charges		0	0	0	0	0
Smart Meter - OM&A	**1555**	**523,438**	**(139,434)**	**384,003**	**305,413**	**235,886**
Smart Meter - OM&A	1556	**403,944**	**46,206**	**450,150**	**793,474**	**861,840**
Carrying Charges		**14,591**	**1,545**	**16,136**	**20,733**	**20,791**
Smart Meter - OM&A	**1556**	**418,534**	**47,751**	**466,285**	**814,207**	**882,631**
PILS	1562	135,171	123,821	258,992	258,992	258,992
Carrying Charges		170,579	11,121	181,699	184,369	184,725
PILS	**1562**	**305,749**	**134,942**	**440,691**	**443,361**	**443,717**
PILS Contra	1563	(135,171)	(123,821)	(258,992)	(258,992)	(258,992)
Carrying Charges		(170,579)	(11,121)	(181,699)	(184,369)	(184,725)
PILS Contra	**1563**	**(305,749)**	**(134,942)**	**(440,691)**	**(443,361)**	**(443,717)**
Transition Costs	1570	0	0	0	0	0

Carrying Charges		0	0	0	0	0
Transition Costs	**1570**	**0**	**0**	**0**	**0**	**0**
RSVA-Whlsle Market Serv	1580	0	(24,732)	(24,732)	(118,022)	(328,384)
Carrying Charges		0	1,928	1,928	1,284	1,071
RSVA-Whlsle Market Serv	**1580**	**0**	**(22,803)**	**(22,803)**	**(116,738)**	**(327,313)**
RSVA-One Time Charges	1582	0	(2,428)	(2,428)	16,280	26,635
Carrying Charges		0	(313)	(313)	(275)	(245)
RSVA-One Time Charges	**1582**	**0**	**(2,741)**	**(2,741)**	**16,006**	**26,390**
RSVA-Trans Network	1584	0	(92,514)	(92,514)	(9,148)	45,866
Carrying Charges		0	(3,956)	(3,956)	(4,956)	(4,930)
RSVA-Trans Network	**1584**	**0**	**(96,470)**	**(96,470)**	**(14,104)**	**40,936**
RSVA-Trans Connection	1586	0	(288,308)	(288,308)	(217,988)	(192,828)
Carrying Charges		0	(62,613)	(62,613)	(66,002)	(66,284)
RSVA-Trans Connection	**1586**	**0**	**(350,921)**	**(350,921)**	**(283,990)**	**(259,111)**
RSVA-Energy	1588	0	87,379	87,379	64,088	245,279
RSVA-Global Adjustment		0	26,114	26,114	1,358,147	766,221
Carrying Charges		0	26,114	26,114	31,728	33,909
RSVA-Power	**1588**	**0**	**139,607**	**139,607**	**1,453,963**	**1,045,409**
Approved Reg Assets		0	716,661	716,661	716,661	716,661
Carrying Charges		0	11,827	11,827	18,143	17,074
Reg Asset Recovery		0	(837,675)	(837,675)	(1,597,435)	(1,663,544)
Approved Reg Assets	**1590**	**0**	**(109,187)**	**(109,187)**	**(862,630)**	**(929,810)**
Approved Reg Assets - 2008		1,635,856	0	1,635,856	1,635,856	1,635,856
Carrying Charges		0	0	0	4,374	5,529
Reg Asset Recovery		0	0	0	(579,172)	(645,348)
Approved Reg Assets	**1595**	**1,635,856**	**0**	**1,635,856**	**1,061,058**	**996,037**
Total w/o LRAM		**2,577,828**	**(483,667)**	**2,094,161**	**2,419,401**	**1,736,599**
LRAM		232,298	19,780	178,614	252,908	252,908
Total with LRAM		**2,810,126**	**(463,887)**	**2,272,776**	**2,672,309**	**1,989,507**

Details of Deferral and Variance Account Balances

The following is a brief synopsis of each of the Deferral Accounts that have balances at March 31, 2010:

Other Regulatory Charges

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
Other Regulatory Assets	**1508**	0	45,025	45,025	45,025	45,025
Carrying Charges		(0)	6,282	6,282	6,794	6,856
Other Regulatory Assets	**1508**	**(0)**	**51,306**	**51,306**	**51,819**	**51,880**

The balance in this account represents OEB invoices for incremental Cost Assessments from January 1, 2004 to April 2006 of approximately $11,862 plus carrying charges of $2,493.

Reimbursement is also requested for eligible OMERS Pension costs paid on behalf of employees from January 1, 2005 to April 30, 2006 of $33,163 plus carrying charges of $4,363.

These costs relate to the Tay service area and have not been applied for to date.

Retail Cost Variance – Retail (Account 1518) and Retail Cost Variance STR (Account 1548)

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
Retail Cost Variance - Retail	1518	0	(943)	(943)	(688)	(499)
Carrying Charges		0	(103)	(103)	(111)	(112)
Retail Cost Variance - Retail	**1518**	**0**	**(1,046)**	**(1,046)**	**(799)**	**(611)**
Retail Cost Variance - STR	1548	0	1,280	1,280	9,270	12,244
Carrying Charges		0	94	94	136	151
Retail Cost Variance - STR	**1548**	**0**	**1,374**	**1,374**	**9,406**	**12,395**

These balances represent the incremental costs offset by related revenues of providing the following services to Retailers:

Service Agreements
Distributor Consolidated Billings
Retailer Consolidated Billings
Split Billing
Service Transaction Requests (STR's)

Miscellaneous Deferred Debits (Account 1525)

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
Misc Deferred Debits	1525	0	2,171	2,171	2,174	2,174
Carrying Charges		0	156	156	180	183
Misc Deferred Debits	**1525**	**0**	**2,326**	**2,326**	**2,354**	**2,357**

This balance is the incremental costs related to the issuance of cheques for the 2005 Rebate Program in the Tay service area.

Low Voltage Charges (Account1550)

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
Low Voltage Variance	1550	0	(3,684)	(3,684)	(16,716)	(40,592)
Carrying Charges		0	255	255	154	113
Low Voltage Variance	**1550**	**0**	**(3,429)**	**(3,429)**	**(16,562)**	**(40,478)**

This account captures the LV costs billed by Hydro One and the offsetting revenues billed to the customers from the currently approved LV rate rider in the Tay service area. NTP is requesting that this Rate Rider be eliminated as part of this application and the rationale is described in Exhibit 8 - Rate Design.

Smart Metering Capital and OM&A (Accounts 1555 & 1556)

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
Smart Meter - Capital	1555	523,438	(139,434)	384,003	305,413	235,886
Carrying Charges		0	0	0	0	0
Smart Meter - OM&A	**1555**	**523,438**	**(139,434)**	**384,003**	**305,413**	**235,886**
Smart Meter - OM&A	**1556**	**403,944**	**46,206**	**450,150**	**793,474**	**861,840**
Carrying Charges		**14,591**	**1,545**	**16,136**	**20,733**	**20,791**
Smart Meter - OM&A	**1556**	**418,534**	**47,751**	**466,285**	**814,207**	**882,631**

Both Newmarket and Tay currently have Smart Meter Rate Adders approved and in place. The Newmarket rate is $0.61/metered customer/month and Tay's is $2.59/metered customer/month. The Newmarket rate was established with the 2008 EDR submission and was designed to recover operational costs only, while Tay's was initially established with the 2006 EDR and updated with the 2007 IRM and was designed to recapture operational as well as capital costs. Following the Ontario Energy Board Smart Meter Funding and Cost Recovery Guideline (G-2008-0002), the Applicant has since calculated the balances for both service areas. The detailed calculations are covered in Exhibit 9, Tab 2, Schedule 1.

Deferred Payments in Lieu of Taxes and Contra (Accounts 1562 &1563)

The Applicant is awaiting the final outcome of the current PILS Proceeding at the Ontario Energy Board, and has not included these accounts in its Application.

RSVA Accounts (1580, 1582, 1584, 1586, 1588)

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
RSVA-Whlsle Market Serv	1580	0	(24,732)	(24,732)	(118,022)	(328,384)
Carrying Charges		0	1,928	1,928	1,284	1,071
RSVA-Whlsle Market Serv	**1580**	**0**	**(22,803)**	**(22,803)**	**(116,738)**	**(327,313)**
RSVA-One Time Charges	1582	0	(2,428)	(2,428)	16,280	26,635
Carrying Charges		0	(313)	(313)	(275)	(245)
RSVA-One Time Charges	**1582**	**0**	**(2,741)**	**(2,741)**	**16,005**	**26,390**
RSVA-Trans Network	1584	0	(92,514)	(92,514)	(9,148)	45,866
Carrying Charges		0	(3,956)	(3,956)	(4,956)	(4,930)
RSVA-Trans Network	**1584**	**0**	**(96,470)**	**(96,470)**	**(14,104)**	**40,936**
RSVA-Trans Connection	1586	0	(288,308)	(288,308)	(217,988)	(192,828)
Carrying Charges		0	(62,613)	(62,613)	(66,002)	(66,284)
RSVA-Trans Connection	**1586**	**0**	**(350,921)**	**(350,921)**	**(283,990)**	**(259,111)**
RSVA-Energy	1588	0	87,379	87,379	64,088	245,279
RSVA-Global Adjustment		0	26,114	26,114	1,358,147	766,221
Carrying Charges		0	26,114	26,114	31,728	33,909
RSVA-Power	**1588**	**0**	**139,607**	**139,607**	**1,453,963**	**1,045,409**

The Wholesale Market Service balance relates primarily to Newmarket. The Load Factor in Newmarket tends to be strong, thus creating a credit balance when the provincially applied rates are used.

One Time charges tend to be unpredictable due to their nature. As discussed in Exhibit 2 – Rate Base, The Applicant is budgeting this account to be $0.00 through the rate period.

Transmission account balances relate mainly to Tay due to a significant error by Hydro One in regard to its RAR1 (RAR = Regulatory Asset Recovery) and RAR2 billings to Tay. The error was related to the ownership of distribution stations within the Tay operating area. Hydro One had calculated the values assuming they owned the stations, while Tay had purchased them from Ontario Hydro many years earlier in an asset transfer. The original calculation for RAR1 and RAR2 was about $311,000. This balance was approved for recovery in 2006 and transferred to 1590. Subsequently the ownership error was found and the RAR1 and RAR2 balances were reduced by >$200,000. The account correction was to credit 1586 Transmission Connection and debit 2405 Other Regulatory Liability thus creating the bulk of the credit balance in 1586.

The balance in RSVA – Global Adjustment is due to the rapid and significant increase in the rate for this component of the Power Bill in early 2009. There is a lag between the date that the Power Bill is paid and the date(s) that the customers are billed at the revised higher rates thus causing the Applicant to fund the difference. The rate started to stabilize during the last half of 2009.

Recovery of Deferred Account Balances (Account 1590)

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
Approved Reg Assets		0	716,661	716,661	716,661	716,661
Carrying Charges		0	11,827	11,827	18,143	17,074
Reg Asset Recovery		0	(837,675)	(837,675)	(1,597,435)	(1,663,544)
Approved Reg Assets	**1590**	**0**	**(109,187)**	**(109,187)**	**(862,630)**	**(929,810)**

This balance is the net of the approved recovery values at the approved recovery rates for both locations. Newmarket and Tay are both in credit positions. As previously mentioned, the recovery rates in Tay were set too high due to the billing error from Hydro One regarding Transmission Costs. Newmarket received approval to recover Deferral Account December 2008 balances (transferred to 1595 effective May 1, 2009).

From January 1 to April 30, 2009 the approved recovery rates were still being applied and the recoveries credited to 1590.

Recovery of Deferred Account Balances - 2008 (Account 1595)

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
Approved Reg Assets - 2008		1,635,856	0	1,635,856	1,635,856	1,635,856
Carrying Charges		0	0	0	4,374	5,529
Reg Asset Recovery		0	0	0	(579,172)	(645,348)
Approved Reg Assets	**1595**	**1,635,856**	**0**	**1,635,856**	**1,061,058**	**996,037**

This account was set up effective May 1, 2009 to capture the 2008 approved Deferral value of $1,635,856 offset by recoveries from May 1, 2009 to March 31, 2010.

Lost Revenue Adjustment Mechanism (LRAM)

	Account	2008 Newmarket	2008 Tay	2008 NT Power	2009 Actual	March 2010 Actual
LRAM		232,298	19,780	178,614	252,908	252,908
Total with LRAM		**2,810,126**	**(463,887)**	**2,272,776**	**2,672,309**	**1,989,507**

The proposed LRAM recovery is covered in detail in Exhibit 9 Tab 3.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Newmarket-Tay Power Distribution Ltd	**LICENCE NUMBER**	ED-2007-0624
NAME OF CONTACT	Iain Clinton	**DOCID NUMBER**	EB-2007-0776
E-mail Address	iclinton@nmhydro.ca		
VERSION NUMBER	v3.0	**PHONE NUMBER**	905-953-8548
Date	24-Sep-08	**(extension)**	2300

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

Account Description	Account Number	2005 Opening Principal Amounts as of Jan-1-05 [1]	Transactions (additions) during 2005, excluding interest and adjustments [6]	Transactions (reductions) during 2005, excluding interest and adjustments [6]	Adjustments during 2005 - instructed by Board [2]	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec31-05	Closing Interest Amounts as of Dec-31-05	2006 Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments [6]	Transactions (reductions) during 2006, excluding interest and adjustments [6]	Adjustments during 2006 - instructed by Board [2]	Adjustments during 2006 - other [3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06	Opening Principal Amounts as of Jan-1-07	Transactions (additions) during 2007, excluding interest and adjustments [6]
RSVA - Wholesale Market Service Charge	1580	-34,725	653,969				619,244	-35,497	17,504	-17,993	619,244	-645,379		0	0	-59,202	-85,337	-17,993	18,884	-16,393	-15,501	-85,337	-917,904
RSVA - One-time Wholesale Market Service	1582	37,634	39,178				76,812	1,977	3,875	5,851	76,812	35,649		0	0	-14,817	97,644	5,851	3,970	-2,407	7,414	97,644	-405
RSVA - Retail Transmission Network Charge	1584	246,992	256,100				503,092	-27,828	26,134	-1,693	503,092	339,107		0	0	60,190	902,389	-1,693	35,770	8,161	42,238	902,389	211,759
RSVA - Retail Transmission Connection Charge	1586	311,842	-254,423				57,419	-35,525	83	-35,442	57,419	114,315		0	0	-276,591	-104,857	-35,442	7,025	-3,059	-31,477	-104,857	139,283
Sub-Totals		561,745	694,823		0	0	1,256,568	-96,873	47,596	-49,277	1,256,568	-156,307		0	0	-290,422	809,839	-49,277	65,649	-13,697	2,675	809,839	-567,267
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	57,115	114,476	0	0	0	171,591	1,642	6,272	7,914	171,591	90,847	0	0	0	0	262,438	7,914	12,511	0	20,425	262,438	87,849
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	0	219,477	0	0	0	219,477	0	3,777	3,777	219,477	247,815	0	0	0	0	467,292	3,777	14,746	0	18,523	467,292	243,370
Other Regulatory Assets - Sub-Account - Mearie	1508	0	16,998	0	0	0	16,998	0	330	330	16,998	21,546	0	0	0	0	38,543	330	1,198	0	1,528	38,543	22,740
Other Regulatory Assets - Sub-Account - Other [7]	1508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other [7]	1508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	26,271	6,088	0	0	0	32,360	2,242	2,154	4,396	32,360	1,057	0	0	0	-5,655	27,762	4,396	1,590	-547	5,439	27,762	9,518
Retail Cost Variance Account - STR	1548	24,958	8,394	0	0	0	33,352	2,383	2,075	4,458	33,352	4,451	0	0	0	-3,044	34,759	4,458	1,690	-294	5,853	34,759	11,791
Misc. Deferred Debits	1525	36,219	-6,469	0	0	0	29,750	4,595	2,436	7,031	29,750	0	0	0	0	-13,654	16,096	7,031	1,418	-2,519	5,930	16,096	0
LV Variance Account	1550	0	0	0	0	0	0	0	0	0	0	5,204	0	0	0	0	5,204	0	45	0	45	5,204	-161
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	0	0	0	0	0	0	0	0	0	0	-7,267	0	0	0	0	-7,267	0	0	0	0	-7,267	-67,015
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Cost:	1555	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Smart Meter OM&A Variance	1556	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Conservation and Demand Management Expenditures and Recoveries	1565	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CDM Contra	1566	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Qualifying Transition Costs [5]	1570	592,023	n/a	n/a	0	-87,625	504,398	86,199	36,565	122,765	504,398	n/a	n/a	0	-44,712	-178,023	281,663	122,765	6,232	-54,297	74,700	281,663	n/a
Pre-Market Opening Energy Variances Total [5]	1571	-45,014	n/a	n/a	0	0	-45,014	0	-3,264	-3,264	-45,014	n/a	n/a	0	0	45,014	0	-3,264	0	4,351	1,088	0	n/a
Extra-Ordinary Event Costs	1572	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Rate Impact Amounts (LRAM)	1525	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Deferred Credits	2425	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub-Totals		691,572	358,964	0	0	-87,625	962,911	97,061	50,345	147,407	962,911	363,654	0	0	-44,712	-155,362	1,126,490	147,407	39,430	-53,306	133,532	1,126,490	308,091
Deferred Payments in Lieu of Taxes	1562					**see PILs reconciliation requested**										**see PILs reconciliation requested**							
2006 PILs & Taxes Variance	1592					**see PILs reconciliation requested**										**see PILs reconciliation requested**							
Sub-Totals						**see PILs reconciliation requested**										**see PILs reconciliation requested**							
Total		1,253,316	1,053,787	0	0	-87,625	2,219,478	188	97,942	98,130	2,219,478	207,347	0	0	-44,712	-445,784	1,936,329	98,130	105,079	-67,003	136,206	1,936,329	-259,177
The following is not included in the total claim but is included on a memo basis:																							
Deferred PILs Contra Account [8]	1563					**see PILs reconciliation requested**										**see PILs reconciliation requested**							
RSVA - Power (including Global Adjustment)	1588	658,216	-283,972		0	0	374,244	-350,762	31,446	-319,316	374,244	726,981		0	0	-172,425	928,800	-319,316	15,629	-31,451	-335,137	928,800	351,974
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	0	-2,834,769		0	0	-2,834,769	0	-45,034	-45,034	-2,834,769	978,646		0	0	0	-1,856,123	-45,034	-249,339	0	-294,373	-1,856,123	1,780,571
Recovery of Regulatory Asset Balances	1590	3,559,070	0	-1,271,890	0	0	2,287,180	235,651	170,089	405,740	2,287,180	0	-1,055,198	0	0	618,208	1,850,190	405,740	77,123	98,454	581,317	1,850,190	0
Recovery of Regulatory Asset Balances 2008	1595																						
																						4,715,319	92,797

C:\Users\mts-schofield\Documents\Documents\Newmarket-Tay\RATEFILES\[E09T01S02A01.xls]Continuity Schedule

1 As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
2 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
3 Provide supporting statement indicating nature of this adjustments and periods they relate to
4 Not included in sub-total

2007							2008									2009											
Transactions (reductions) during 2007, excluding interest and adjustments [6]	Adjustments during 2007 - instructed by Board [2]	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec31-07	Closing Interest Amounts as of Dec-31-07	Opening Principal Amounts as of Jan-1-08	Transactions (additions) during 2008, excluding interest and adjustments [6]	Transactions (reductions) during 2008, excluding interest and adjustments [6]	Adjustments during 2008 - instructed by Board [2]	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec31-08	Closing Interest Amounts as of Dec-31-08	Opening Principal Amounts as of Jan-1-09	Transactions (additions) during 2009, excluding interest and adjustments [6]	Transactions (reductions) during 2009, excluding interest and adjustments [6]	Principal Adjustments during 2009 - instructed by Board [2]	Interest Adjustments during 2009 - instructed by Board [2]	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec31-09	Closing Interest Amounts as of Dec-31-09	Opening Principal Amounts as of Jan-1-10	Transactions (additions) during 2010, excluding interest and adjustments [6]
	0	0	-1,003,241	-15,501	-19,976	-35,478	-1,003,241	-377,800		0	0	-1,381,040	-35,478	-46,831	-82,308	-1,381,040	-93,290		1,356,309	84,237		-118,022	-82,308	-644	1,284	-118,022	-210,361
	0	0	97,239	7,414	4,988	12,402	97,239	-13,767		0	0	83,472	12,402	3,658	16,060	83,472	18,708		-85,900	-16,372		16,280	16,060	38	-275	16,280	10,355
	0	0	1,114,148	42,238	43,736	85,974	1,114,148	-578,678		0	0	535,470	85,974	31,291	117,265	535,470	83,366		-627,984	-121,220		-9,148	117,265	-1,000	-4,956	-9,148	55,014
	0	0	34,425	-31,477	-32,980	-64,456	34,425	-274,027		0	0	-239,601	-64,456	-4,795	-69,252	-239,601	70,319		-48,706	6,639		-217,988	-69,252	-3,389	-66,002	-217,988	25,161
	0	0	242,572	2,675	-4,233	-1,558	242,572	-1,244,272		0	0	-1,001,700	-1,558	-16,678	-18,236	-1,001,700	79,103		593,719	-46,717		-328,878	-18,236	-4,995	-69,949	-328,878	-119,832
0	0	0	350,286	20,425	14,219	34,645	350,286	98,561	0	0	0	448,847	34,645	12,641	47,285	448,847	0	0	-436,985	-44,950		11,862	47,285	4,458	6,794	11,862	0
0	0	-20,217	690,444	18,523	25,920	44,443	690,444	274,083	0	0	0	964,527	44,443	34,425	78,868	964,527	0	0	-931,364	-74,921		33,163	78,868	-3,946		33,163	0
0	0	0	61,284	1,528	2,314	3,842	61,284	27,078	0	0	0	88,362	3,842	3,290	7,132	88,362	0	0	-88,362	-7,132			7,132	0		0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				0	0		0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				0	0		0	0
0	0	0	37,280	5,439	1,784	7,224	37,280	5,651	0	0	0	42,931	7,224	3,225	10,449	42,931	255	0	-43,874	-10,551		-688	10,449	-9	-111	-688	189
0	0	0	46,550	5,853	2,041	7,895	46,550	8,646	0	0	0	55,196	7,895	1,996	9,890	55,196	7,989	0	-53,916	-9,797		9,270	9,890	43	136	9,270	2,974
0	0	13,654	29,750	5,930	1,951	7,881	29,750	-0	0	0	0	29,750	7,881	1,184	9,065	29,750	3	0	-27,579	-8,909		2,174	9,065	24	180	2,174	0
0	0	0	5,043	45	249	294	5,043	-8,727	0	0	0	-3,684	294	-39	255	-3,684	-13,032	0	0			-16,716	255	-101	154	-16,716	-23,876
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	488,740	0	0			488,740	0	23,014	23,014	488,740	27,674
0	0	0	-74,282	0	0	0	-74,282	-125,211	0	0	0	-199,493	0	0	0	-199,493	-125,714	0	0			-325,207	0	0		-325,207	-31,594
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				0	0		0	0
0	0	0	0	0	0	0	0	0	0	0	49,917	49,917	0	0	0	49,917	315,875	0	-49,914	-3,628		315,878	0	5,963	2,336	315,878	44,235
0	0	0	-10,018	0	0	0	-10,018	0	0	0	0	-10,018	0	0	0	-10,018	10,018	0	0				0	0		0	0
0	0	0	10,018	0	0	0	10,018	0	0	0	0	10,018	0	0	0	10,018	-10,018	0	0				0	0		0	0
n/a	0	0	281,663	74,700	13,316	88,016	281,663	n/a	n/a	0	0	281,663	88,016	11,210	99,226	281,663	0	n/a	-281,663	-99,226			99,226	-0		0	0
n/a	0	0	0	1,088	-1,088	0	0	n/a	n/a	0	0	0	0	0	0	0	0	n/a	0				0	0		0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				0	0		0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				0	0		0	0
0	0	-6,563	1,428,018	133,532	60,707	194,238	1,428,018	280,080	0	0	49,917	1,758,015	194,238	67,932	262,170	1,758,015	674,117	0	-1,913,657	-259,115		518,475	262,170	29,447	32,502	518,475	19,603
	see PILs reconciliation requested									see PILs reconciliation requested																	
	see PILs reconciliation requested									see PILs reconciliation requested																	
	see PILs reconciliation requested									see PILs reconciliation requested																	
0	0	-6,563	1,670,589	136,206	56,474	192,680	1,670,589	-964,192	0	0	49,917	756,315	192,680	51,254	243,934	756,315	753,220		-1,319,937	-305,832		189,597	243,934	24,451	-37,446	189,597	-100,229
	see PILs reconciliation requested									see PILs reconciliation requested																	
	0	0	1,280,774	-335,137	41,107	-294,030	1,280,774	-114,431		0	0	1,166,344	-294,030	48,371	-245,659	1,166,344	1,334,856		-1,078,965	271,773		1,422,235	-245,659	5,614	31,728	1,422,235	-410,735
	0	0	-75,552	-294,373	-50,297	-344,671	-75,552	1,787,254		0	0	1,711,702	-344,671	26,668	-318,002	1,711,702	-353,161		0			1,358,541	-318,002	339,874	21,871	1,358,541	-592,320
-1,814,051	0	0	36,139	581,317	-60,504	520,813	36,139	0	-1,154,409	0	0	-1,118,271	520,813	-308,838	211,975	-1,118,271	-635,082		997,253	-200,148		-756,099	211,975	-118,358	-106,531	-756,099	-66,110
																	-583,820		1,401,649	234,208		817,829	0	-100,008	134,199	817,829	-89,677
-1,814,051	0	-6,563	2,987,502	382,386	37,077	419,463	2,987,502	-1,078,623	-1,154,409	0	49,917	804,387	419,463	-209,212	210,251	804,387			0	0		1,673,561			21,950	1,673,561	-666,750
			2,987,502			419,463						804,387															
			0			0						0															
			-1,032,430			-37,290																					
			128,856			14,431													-997,257								
			1,097,051			87,731																					
			261,527			-27,751																					
			455,004			37,121																					
			350286			34644.56381																					
			690444.1			44442.54558																					
			61283.56			3841.961561																					
			0			0																					
			0			0																					
			37280.17			7223.581806																					
			46550.33			7894.617344																					
			29749.89			7881.402057																					
			5043.035681			293.8319444																					
			0			0																					
			-74282.23541			0																					
			0			0																					
			49914			0																					
			0			0																					
			0			0																					
			281663			88015.7024																					
			-1088			0																					
			0			0																					
			0			0																					
			0			0																					
			1476843.85			194238.2065																					
						-312109																					
						-225889.248																					
						685694.0239																					

2010										
Transactions (reductions) during 2010, excluding interest and adjustments [6]	Principal Adjustments during 2010 - instructed by Board [2]	Interest Adjustments during 2010 - instructed by Board [2]	Adjustments during 2010 - other [3]	Closing Principal Balance as of Mar-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Mar 31-10	Closing Interest Amounts as of Mar-31-10	Mar RRR Filing	Adjustment 2010	Total Claim
				-328,384	1,284	-213	1,071	-327,313		-327,313
				26,635	-275	30	-245	26,390		26,390
				45,866	-4,956	26	-4,930	40,936		40,936
				-192,828	-66,002	-282	-66,284	-259,111		-259,111
								0		
				-448,710	-69,949	-439	-70,388	-519,098		-519,098
				11,862	6,794	62	6,856	18,718		18,718
				33,163	0	0		33,163		33,163
					0	0		0		0
					0	0		0		0
					0	0		0		0
				-499	-111	-1	-112	-611		-611
				12,244	136	14	151	12,395		12,395
				2,174	180	3	183	2,357		2,357
				-40,592	154	-41	113	-40,478		-40,478
				516,414	23,014	245	23,258	539,672	212,077	751,749
				-356,801	0	0		-356,801	-159,062	-515,863
					0	0		0		0
				360,113	2,336	437	2,773	362,886	519,920	882,806
					0	0		0		0
						0		0		0
								0		0
								0		0
								0		0
								0		0
								0		0
				538,078	32,502	719	33,222	571,300	572,936	1,144,235
				89,368	-37,446	280	-37,166	52,202	572,936	625,137
				1,011,500	31,728	2,181	33,909	1,045,409		1,045,409
				766,221	21,871	6,461	28,332	794,552		794,552
				-822,209	-106,531	-1,070	-107,601	-929,810		-929,810
				728,152	134,199	-25,376	108,824	836,975	159,062	996,037
				1,006,811	21,950	-23,985	-2,035	1,004,776	731,998	**1,736,774**

Exhibit 9: Deferral And Variance Accounts

Tab 2 (of 3): Lost Revenue Adjustment Mechanism (LRAM)

LRAM OVERVIEW

On May 31, 2004, the Minister of Energy granted approval to all distributors in Ontario to apply to the Board for an increase of their 2005 rates in the amount of the third installment of their incremental market adjusted revenue requirement (“MARR”). The approval was conditional on a commitment to reinvest an equivalent amount in CDM initiatives.

On February 17, 2005, the OEB granted final approval to The Applicant to proceed with a Conservation and Demand Management Plan. The Applicant has also been participating in Ontario Power Authority (“OPA”) funded conservation programs since 2006. The OPA programs implemented by The Applicant are: Every Kilowatt Counts, Cool Savings Rebate Program, Great Refrigerator Roundup and Demand Response Programs.

Through these proceedings, the OEB has authorized distributors to apply for Lost Revenue Adjustment Mechanism “LRAM” and Shared Savings Mechanism “SSM” adjustments. The authorization to apply for LRAM and SSM adjustments from 2005 to 2008 is derived from the OEB’s December 2004 Decision on the Pollution Probe motion (RP-2004-0203); the OEB’s May 2005 Report on the 2006 Electricity Distribution Rate Handbook “the Report”, (RP-2004-0188); and the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037), issued on March 28, 2008.

As a result of the successful implementation of these various conservation programs, the Applicant has experienced loss of distribution revenue, and is therefore applying to the OEB for recovery through the LRAM in the amount of $252,078, as detailed in Exhibit 9 Tab 2, Schedule 4. The LRAM recovery amounts being sought pertain solely to OPA sponsored programs for the years 2006 to 2009 inclusive. Details for these amounts are described in the following section.

Since The Applicant is only applying for OPA programs, and the published results from the OPA were used to determine its loss revenues, the need for a large, complex and expensive, 3rd party review as traditionally completed, is not warranted or prudent. All programs are being delivered in accordance to OPA guidelines. As such, very little uncertainty exists in either the technology details or the related published energy savings.

Also, please note that The Applicant is not seeking to recover SSM in this proceeding.

OPA PROGRAM DETAILS

The following tables are a portion of the OPA spreadsheet detailing the LRAM loads and consumptions. Please note that The Applicant has added the class affected and converted MW to kW and MWh to kWh..

Initiative Name	Year	Results Status	Class	Net Summer Peak Demand Savings (MW)			
				2006	2007	2008	2009
2006 Every Kilowatt Counts (spring)	2006	Final	Res	0.01	0.01	0.01	0.01
2006 Cool Savings Rebate Program	2006	Final	Res	0.07	0.07	0.07	0.07
2006 Secondary Fridge Retirement Pilot	2006	Final	Res	0.01	0.01	0.01	0.01
2006 Every Kilowatt Counts (fall)	2006	Final	Res	0.02	0.02	0.02	0.02
2006 Demand Response 1	2006	Final	> 50 Kw	0.32	0.32	0.32	0.00
2006 Subtotal				**0.42**	**0.42**	**0.42**	**0.11**
2007 Great Refrigerator Roundup	2007	Final	Res	0.00	0.01	0.01	0.01
2007 Cool Savings Rebate	2007	Final	Res	0.00	0.13	0.13	0.13
2007 Aboriginal – Pilot	2007	Final	Res	0.00	0.00	0.00	0.00
2007 Every Kilowatt Counts	2007	Final	Res	0.00	0.03	0.03	0.03
2007 peaksaver®	2007	Final	Res	0.00	0.00	0.00	0.00
2007 Summer Savings	2007	Final	Res	0.00	0.30	0.30	0.00
2007 Affordable Housing – Pilot	2007	Final	Res	0.00	0.00	0.00	0.00
2007 Social Housing – Pilot	2007	Final	Res	0.00	0.01	0.01	0.01
2007 Energy Efficiency Assistance for Houses – Pilot	2007	Final	Res	0.00	0.01	0.01	0.01
2007 Toronto Comprehensive	2007	Final		0.00	0.00	0.00	0.00
2007 Electricity Retrofit Incentive Program	2007	Final	> 50 Kw	0.00	0.01	0.01	0.01
2007 Demand Response 1	2007	Final	> 50 Kw	0.00	0.06	0.06	0.00
2007 Other Demand Response	2007	Final	> 50 Kw	0.00	0.03	0.03	0.00
2007 Renewable Energy Standard Offer	2007	Final		0.00	0.00	0.00	0.00
2007 Subtotal				**0.00**	**0.59**	**0.59**	**0.20**

Initiative Name	Year	Results Status	Class	Net Summer Peak Demand Savings (MW)			
				2006	2007	2008	2009
2008 Great Refrigerator Roundup	2008	Final	Res	0.00	0.00	0.04	0.04
2008 Cool Savings Rebate	2008	Final	Res	0.00	0.00	0.10	0.10
2008 Aboriginal	2008	Final	Res	0.00	0.00	0.00	0.00
2008 Summer Sweepstakes	2008	Final	Res	0.00	0.00	0.13	0.08
2008 Every Kilowatt Counts Power Savings Event	2008	Final	Res	0.00	0.00	0.04	0.04
2008 peaksaver®	2008	Final	Res	0.00	0.00	0.51	0.51
2008 Electricity Retrofit Incentive	2008	Final	> 50 Kw	0.00	0.00	0.11	0.11
2008 Toronto Comprehensive	2008	Final		0.00	0.00	0.00	0.00
2008 High Performance New Construction	2008	Final		0.00	0.00	0.00	0.00
2008 Power Savings Blitz	2008	Final	< 50 Kw	0.00	0.00	0.03	0.03
2008 Chiller Plant Re-Commissioning	2008	Final		0.00	0.00	0.00	0.00
2008 Demand Response 1	2008	Final	> 50 Kw	0.00	0.00	0.68	0.00
2008 Demand Response 3	2008	Final	> 50 Kw	0.00	0.00	0.48	0.48
2008 Other Demand Response	2008	Final	> 50 Kw	0.00	0.00	0.02	0.00
2008 LDC Custom	2008	Final		0.00	0.00	0.00	0.00
2008 Renewable Energy Standard Offer	2008	Final		0.00	0.00	0.00	0.00
2008 Other Customer Based Generation	2008	Final		0.00	0.00	0.00	0.00
2008 Subtotal				**0.00**	**0.00**	**2.14**	**1.38**
Overall Total (Mw)				**0.42**	**1.01**	**3.15**	**1.68**
Overall Total (Kw) - Mw x 1,000				**422.21**	**1,012.63**	**3,145.55**	**1,682.64**

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Initiative Name	Year	Results Status	Class	Net Annual Energy Savings (MWh)			
				2006	2007	2008	2009
2006 Every Kilowatt Counts (spring)	2006	Final	Res	893	893	893	893
2006 Cool Savings Rebate Program	2006	Final	Res	68	68	68	68
2006 Secondary Fridge Retirement Pilot	2006	Final	Res	37	37	37	37
2006 Every Kilowatt Counts (fall)	2006	Final	Res	1,448	1,448	1,448	1,448
2006 Demand Response 1	2006	Final	> 50 Kw	0	0	0	0
2006 Subtotal				**2,446**	**2,446**	**2,446**	**2,446**
2007 Great Refrigerator Roundup	2007	Final	Res	0	129	129	129
2007 Cool Savings Rebate	2007	Final	Res	0	199	199	199
2007 Aboriginal – Pilot	2007	Final	Res	0	0	0	0
2007 Every Kilowatt Counts	2007	Final	Res	0	870	860	860
2007 peaksaver®	2007	Final	Res	0	0	0	0
2007 Summer Savings	2007	Final	Res	0	536	536	0
2007 Affordable Housing – Pilot	2007	Final	Res	0	0	0	0
2007 Social Housing – Pilot	2007	Final	Res	0	78	78	78
2007 Energy Efficiency Assistance for Houses – Pilot	2007	Final	Res	0	21	21	21
2007 Toronto Comprehensive	2007	Final		0	0	0	0
2007 Electricity Retrofit Incentive Program	2007	Final	> 50 Kw	0	16	16	16
2007 Demand Response 1	2007	Final	> 50 Kw	0	0	0	0
2007 Other Demand Response	2007	Final	> 50 Kw	0	0	0	0
2007 Renewable Energy Standard Offer	2007	Final		0	0	0	0
2007 Subtotal				**0**	**1,849**	**1,839**	**1,303**

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Initiative Name	Year	Results Status	Class	Net			
				Annual Energy Savings (MWh)			
				2006	2007	2008	2009
2008 Great Refrigerator Roundup	2008	Final	Res	0	0	327	327
2008 Cool Savings Rebate	2008	Final	Res	0	0	153	153
2008 Aboriginal	2008	Final	Res	0	0	0	0
2008 Summer Sweepstakes	2008	Final	Res	0	0	517	187
2008 Every Kilowatt Counts Power Savings Event	2008	Final	Res	0	0	784	780
2008 peaksaver®	2008	Final	Res	0	0	10	10
2008 Electricity Retrofit Incentive	2008	Final	> 50 Kw	0	0	569	569
2008 Toronto Comprehensive	2008	Final		0	0	0	0
2008 High Performance New Construction	2008	Final		0	0	0	0
2008 Power Savings Blitz	2008	Final	< 50 Kw	0	0	207	207
2008 Chiller Plant Re-Commissioning	2008	Final		0	0	0	0
2008 Demand Response 1	2008	Final	> 50 Kw	0	0	0	0
2008 Demand Response 3	2008	Final	> 50 Kw	0	0	0	0
2008 Other Demand Response	2008	Final	> 50 Kw	0	0	0	0
2008 LDC Custom	2008	Final		0	0	0	0
2008 Renewable Energy Standard Offer	2008	Final		0	0	0	0
2008 Other Customer Based Generation	2008	Final		0	0	0	0
2008 Subtotal				**0**	**0**	**2,567**	**2,234**
Overall Total (Mwh)				**2,446**	**4,295**	**6,852**	**5,982**
Overall Total (Kwh) - Mwh x 1,000				**2,445,624**	**4,294,836**	**6,851,697**	**5,982,032**

WEIGHTED AVERAGE RATES

The OPA results spreadsheet is based on a combined total for the two service areas. The Applicant simply apportioned the results to the 2 service areas by class based on kW and kWh of total sales. Weighted average rates were then calculated using the approved rates for the specific year of the program.

Weighted Average Rate Calculation

		2006	2007	2008	2009
Newmarket					
Residential	**Rate**	0.0135	0.0135	0.0135	0.0136
	kWh	234,727,759	236,692,554	237,633,149	241,609,786
	$	3,168,825	3,195,349	3,208,048	3,285,893
GS <50 kWh	**Rate**	0.0171	0.0171	0.0171	0.0159
	kWh	89,015,948	92,462,338	92,053,329	90,194,118
	$	1,522,173	1,581,106	1,574,112	1,434,086
GS >50 kW	**Rate**	3.2075	3.2075	3.2075	4.3252
	kW	865,283	863,096	862,379	806,353
	$	2,775,397	2,768,379	2,766,081	3,487,638
Tay					
Residential	**Rate**	0.0100	0.0101	0.0101	0.0101
	kWh	31,288,685	32,392,173	33,030,974	32,067,477
	$	312,887	327,161	333,613	323,882
GS <50 kW	**Rate**	0.0163	0.0165	0.0165	0.0165
	kWh	4,984,526	4,728,953	5,206,588	5,144,623
	$	81,248	78,028	85,909	84,886
GS >50 kW	**Rate**	2.7431	2.7726	2.7726	2.7726
	kW	12,190	12,190	14,244	13,587
	$	33,440	33,799	39,493	37,671
NTP					
Residential	**W/A Rate**	0.0131	0.0131	0.0131	0.0132
	kWh	266,016,444	269,084,727	270,664,123	273,677,263
	$	3,481,712	3,522,510	3,541,660	3,609,775
GS <50 kW	**W/A Rate**	0.0171	0.0171	0.0171	0.0159
	kWh	94,000,474	97,191,291	97,259,917	95,338,741
	$	1,603,420	1,659,134	1,660,021	1,518,973
GS >50 kW	**W/A Rate**	3.2010	3.2014	3.2004	4.2995
	kW	877,474	875,286	876,623	819,940
	$	2,808,836	2,802,178	2,805,574	3,525,309

LRAM CALCULATION

The reduction in distribution revenue is calculated on the foregone volumes resulting from CDM activities by class and at the variable distribution rates applicable to the years 2006, 2007, 2008 and 2009. The Applicant has calculated the LRAM values based on the reductions of kW and kWh as published by the OPA for the individual distribution utilities within the province. Rates have been calculated using weighted average approved distribution rates (i.e. without rate adders).

All parameters used to calculate lost revenues are based on net savings and therefore exclude free riders.

The Applicant is requesting that the LRAM amount be recovered through the deferral and variance accounts and that the total amount be recovered over a two year period, consistent with the time frame identified for clearance of the variance and deferral accounts.

LRAM Calculation

	2006	2007	2008	2009	2006	2007	2008	2009
Total kW / kWh per OPA Report	**422**	**1,013**	**3,145**	**1,682**	**2,445,624**	**4,294,836**	**6,851,360**	**5,981,695**
	kW	**kW**	**kW**	**kW**	**kWh**	**kWh**	**kWh**	**kWh**
Residential	106	599	1,416	1,060	2,445,624	4,278,716	6,059,130	5,189,469
Weighted Average Rate	0.0000	0.0000	0.0000	0.0000	0.0131	0.0131	0.0131	0.0132
Annual LRAM Calculation	0	0	0	0	32,009	56,011	79,284	68,449
Total LRAM for the Class								235,753
GS <50 kWh	0	0	28	28	0	0	206,714	206,714
Weighted Average Rate	0.0000	0.0000	0.0000	0.0000	0.0171	0.0171	0.0171	0.0159
Annual LRAM Calculation	0	0	0	0		0	3,528	3,293
Total LRAM for the Class								6,822
GS >50 kW	317	414	1,701	593	0	16,120	585,516	585,512
Weighted Average Rate	3.2010	3.2014	3.2004	4.2995	0.0000	0.0000	0.0000	0.0000
Annual LRAM Calculation	1,014	1,324	5,443	2,552	0	0	0	0
Total LRAM for the Class				10,333				0
Total LRAM kW/kWh	422	1,013	3,145	1,682	2,445,624	4,294,836	6,851,360	5,981,695
Total LRAM $	1,014	1,324	5,443	2,552	32,009	56,011	82,812	71,742
Grand Total LRAM $								**252,908**

BILL IMPACTS

The Applicant proposes that the LRAM amounts be recovered over two years through rate riders effective in conjunction with its proposed rates. The table below provides a summary of the impacts of the proposed LRAM adjustments under various consumption scenarios in each affected rate class.

Summary of Bill Impacts Based on Total Bill Before Tax						
Class	**kWh/Mn**	**kW/Mn**	**Total Bill with LRAM**	**Total Bill without LRAM**	**LRAM Component**	**% of Bill**
Residential	100		27.42	27.38	0.04	0.16%
	250		42.68	42.57	0.11	0.25%
	500		68.11	67.90	0.21	0.32%
	800		100.69	100.35	0.34	0.34%
	1,000		122.90	122.47	0.43	0.35%
GS Less than 50 kW	1,000		138.65	138.61	0.04	0.03%
	2,000		250.80	250.73	0.07	0.03%
	5,000		587.26	587.07	0.18	0.03%
	10,000		1,148.01	1,147.64	0.37	0.03%
GS Greater Than 50 kW	25,000	60	2,777.99	2,777.62	0.37	0.01%
	40,000	100	4,327.51	4,326.90	0.61	0.01%
	200,000	500	21,063.57	21,060.50	3.07	0.01%
	400,000	1,000	41,983.64	41,977.50	6.14	0.01%

Exhibit 9: Deferral And Variance Accounts

Tab 3 (of 3): Smart Meters

SMART METER DEPLOYMENT PLAN STATUS

Background

The Applicant calculated the Smart Meter Operation and Maintenance (1555) and Smart Meter Capital Cost (1556) balances by following the Smart Meter Funding and Cost Recovery Guideline (G-2008-0002) issued by the Ontario Energy Board on October 22, 2008. The 2 service areas were handled differently throughout the implementation process and therefore must be viewed independently here.

<u>Newmarket</u>

Newmarket is a leader in the Smart Meter Program starting as a test sight in 2006. Initially about 250 homes were involved and the data gathered from this test was pivotal in the implementation of the program on a province wide basis. This was prior to the amalgamation with Tay in 2007.

Once the pilot program was completed, the balance of the Smart Meters were installed in 2007, 2008 and finished in 2009 with the bulk of the installations being done in 2007. Times of Use Rates were implemented to the residential class in 2008 and 2009. Parallel manual meter readings were gathered until September of 2009 when the residential portion of the project was declared complete.

All capital costs were funded by the Applicant through this period. With its 2008 rate submission The Applicant requested that the Smart Meters be part of the rebasing and this was approved. The Applicant also requested that incremental O&M costs be included in the rates as well. This request was denied since there was not enough history to determine what these costs would be. A rate adder of $0.61 per month per metered customer was approved to compensate The Applicant for these costs. This rate adder went into effect on May 1, 2009.

<u>Tay</u>

The installation of the Smart Meters and Time of Use Rates basically followed the Newmarket path with the exception of the testing period in 2006. Deployment was completed in 2008 and by September of 2009 all eligible residential customers are receiving a TOU bill.

Tay requested a rate adder in 2006 and updated it in 2007 through the IRM process. Tay Smart Meters are not currently in the Rate Base and are therefore part of this rebasing submission.

Calculations

Due to the timing and rate treatment differences between Newmarket and Tay, the calculations have to be done individually for each service area and then combined to match The Applicant's current approach. Capital calculations for Newmarket span from 2006 with the test program running until May 1, 2009 when the Smart Meters were included in the rate base. Tay starts in 2007 and ends on March 31, 2010 with this rebasing request. Cost of Capital factors are also different through part of the period due to the different rate approval periods that the service areas are operating under. For the purpose of these calculations, the lower cost factors (Tay) are used for both locations.

SMART METER RATE ADDER AMOUNTS

With the approval of the submissions in this section, The Applicant requests that the current Smart Meter rate adders be discontinued. The individual results and the aggregate impacts of this proposal are shown in the following tables.

Smart Meter Capital and O&M - Newmarket

		Actual 2006				Actual 2007			
	USoA	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556
Smart Meter Additions -Current Year		294,833				3,296,111			
Life to Date Balance		294,833				3,590,944			
Amortization - Current Year		(9,828)				(129,526)			
Amortization - Life to Date		(9,828)				(139,354)			
Book Value Yr End		285,005				3,451,590			
Book Value Average		142,503				1,868,298			
Debt Ratio - Long Term	**1555**	50.00%	6.10%	4,346	4,346	50.00%	6.10%	56,983	61,329
Debt Ratio - Short Term	**1555**		4.47%		0	0.00%	4.47%	0	0
Equity Ratio	**1555**	50.00%	8.57%	6,106	6,106	50.00%	8.57%	80,057	86,163
PIL Uplift	**1555**			2,874	2,874			37,674	40,547
Amortization (15 yrs)	**1556**		6.67%	9,828	9,828		6.67%	129,526	139,354
Incremental O&M	**1556**			0	0			0	0
Carrying Charges O&M / Amort	**1556**		5.14%	253	253		4.73%	3,526	3,779
Funding Through SM Adder	**1555**								
Total				**23,407**	**23,407**			**307,765**	**331,172**
Capital	**1555**			**13,326**	**13,326**			**174,713**	**188,039**
O&M	**1556**			**10,080**	**10,080**			**133,052**	**143,133**

Smart Meter Capital and O&M - Newmarket

		Actual 2008				2009 (1555 to Apr 30)			
	USoA	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556
Smart Meter Additions -Current Year		755,816				106,933			
Life to Date Balance		4,346,759				4,453,693			
Amortization - Current Year		(264,590)				(97,783)			
Amortization - Life to Date		(403,944)				(501,727)			
Book Value Yr End		3,942,816				3,951,966			
Book Value Average		3,697,203				3,947,391			
Debt Ratio - Long Term	**1555**	49.30%	6.10%	111,186	172,515	56.00%	6.10%	44,948	217,463
Debt Ratio - Short Term	**1555**	4.00%	4.47%	6,611	6,611	4.00%	4.47%	2,353	8,963
Equity Ratio	**1555**	46.70%	8.57%	147,969	234,132	40.00%	8.57%	45,106	279,237
PIL Uplift	**1555**			69,633	110,180			21,226	131,406
Amortization (15 yrs)	**1556**		6.67%	264,590	403,944		6.67%	97,783	501,727
Incremental O&M	**1556**			0	0			176,676	176,676
Carrying Charges O&M / Amort	**1556**		3.98%	10,812	14,591		2.09%	3,214	17,804
Funding Through SM Adder	**1555**							(109,030)	(109,030)
Total				**610,800**	**941,972**			**282,274**	**1,224,246**
Capital	**1555**			**335,398**	**523,438**			**4,602**	**528,039**
O&M	**1556**			**275,402**	**418,534**			**277,672**	**696,207**

Smart Meter Capital and O&M - Newmarket

		2010 to Mar 31			
	USoA	**Additions and COC Split**	**Annual Factors**	**Annual Impact 1555/1556**	**Life to Date 1555/1556**
Smart Meter Additions -Current Year					
Life to Date Balance					
Amortization - Current Year				Fixed Assets in Rate Base	
Amortization - Life to Date					
Book Value Yr End					
Book Value Average					
Debt Ratio - Long Term	**1555**			0	217,463
Debt Ratio - Short Term	**1555**			0	8,963
Equity Ratio	**1555**			0	279,237
PIL Uplift	**1555**			0	131,406
Amortization (15 yrs)	**1556**			0	501,727
Incremental O&M	**1556**			52,537	229,213
Carrying Charges O&M / Amort	**1556**		0.55%	171	17,975
Funding Through SM Adder	**1555**			(50,032)	(159,062)
Total				**2,676**	**1,226,922**
Capital	**1555**			**(50,032)**	**478,008**
O&M	**1556**			**52,708**	**748,914**

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Smart Meter Capital and O&M - Tay

		2007				2008			
	USoA	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556
Smart Meter Additions -Current Year		430,959				93,301			
Life to Date Balance		430,959				524,260			
Amortization - Current Year		(14,365)				(31,841)			
Amortization - Life to Date		(14,365)				(46,206)			
Book Value Yr End		416,594				478,054			
Book Value Average		208,297				447,324			
Debt Ratio - Long Term	**1555**	50.00%	6.10%	6,353	6,353	49.30%	6.10%	13,452	19,805
Debt Ratio - Short Term	**1555**		4.47%	0	0	4.00%	4.47%	800	800
Equity Ratio	**1555**	50.00%	8.57%	8,926	8,926	46.70%	8.57%	17,903	26,828
PIL Uplift	**1555**			4,200	4,200			8,425	12,625
Amortization (15 yrs)	**1556**		6.67%	14,365	14,365		6.67%	31,841	46,206
Incremental O&M	**1556**				0			0	0
Carrying Charges O&M / Amort	**1556**		4.73%	340	340		3.98%	1,205	1,545
Funding Through SM Adder	**1555**			(74,282)	(74,282)			(125,211)	(199,493)
Total				**(40,099)**	**(40,099)**			**(51,585)**	**(91,683)**
Capital	**1555**			**(54,803)**	**(54,803)**			**(84,631)**	**(139,434)**
O&M	**1556**			**14,705**	**14,705**			**33,046**	**47,751**

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Smart Meter Capital and O&M – Tay

		2009				2010 to Mar 31			
	USoA	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556
Smart Meter Additions -Current Year		86,017				335			
Life to Date Balance		610,277				610,612			
Amortization - Current Year		(37,818)				(10,174)			
Amortization - Life to Date		(84,024)				(94,198)			
Book Value Yr End		526,253				516,414			
Book Value Average		502,153				521,333			
Debt Ratio - Long Term	**1555**	56.00%	6.10%	17,154	36,959	56.00%	6.10%	4,452	41,411
Debt Ratio - Short Term	**1555**	4.00%	4.47%	898	1,698	4.00%	4.47%	233	1,931
Equity Ratio	**1555**	40.00%	8.57%	17,214	44,042	40.00%	8.57%	4,468	48,510
PIL Uplift	**1555**			8,101	20,726			2,103	22,828
Amortization (15 yrs)	**1556**		6.67%	37,818	84,024		6.67%	10,174	94,198
Incremental O&M	**1556**			31,048	31,048			5,655	36,703
Carrying Charges O&M / Amort	**1556**		2.09%	1,383	2,928		0.55%	63	2,991
Funding Through SM Adder	**1555**			(126,558)	(326,051)			(30,751)	(356,801)
Total				**(12,943)**	**(104,626)**			**(3,603)**	**(108,230)**
Capital	**1555**			**(83,192)**	**(222,626)**			**(19,495)**	**(242,121)**
O&M	**1556**			**70,249**	**118,000**			**15,892**	**133,892**

Smart Meter Capital and O&M - NTP

		Actual 2006				Actual 2007			
	USoA	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556
Smart Meter Additions -Current Year		294,833				3,727,070			
Life to Date Balance		294,833				4,021,903			
Amortization - Current Year		(9,828)				(143,891)			
Amortization - Life to Date		(9,828)				(153,719)			
Book Value Yr End		285,005				3,868,184			
Book Value Average		142,503				2,076,595			
Debt Ratio - Long Term	**1555**	50.00%	6.10%	4,346	4,346	50.00%	6.10%	63,336	67,682
Debt Ratio - Short Term	**1555**		4.47%		0	0.00%	4.47%	0	0
Equity Ratio	**1555**	50.00%	8.57%	6,106	6,106	50.00%	8.57%	88,982	95,088
PIL Uplift	**1555**			2,874	2,874			41,874	44,747
Amortization (15 yrs)	**1556**		6.67%	9,828	9,828		6.67%	143,891	153,719
Incremental O&M	**1556**			0	0			0	0
Carrying Charges O&M / Amort	**1556**		5.14%	253	253		3.98%	3,866	4,118
Funding Through SM Adder	**1555**				0			(74,282)	(74,282)
Total				**23,406**	**23,406**			**267,667**	**291,073**
Capital	**1555**			**13,326**	**13,326**			**119,910**	**133,236**
O&M	**1556**			**10,080**	**10,080**			**147,757**	**157,837**

Smart Meter Capital and O&M - NTP

		Actual 2008				2009			
	USoA	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556	Additions and COC Split	Annual Factors	Annual Impact 1555/1556	Life to Date 1555/1556
Smart Meter Additions -Current Year		849,116				192,950			
Life to Date Balance		4,871,019				5,063,970			
Amortization - Current Year		(296,431)				(135,601)			
Amortization - Life to Date		(450,150)				(585,750)			
Book Value Yr End		4,420,869				4,478,219			
Book Value Average		4,144,527				4,449,544			
Debt Ratio - Long Term	**1555**	49.30%	6.10%	124,638	192,321	56.00%	6.10%	62,101	254,422
Debt Ratio - Short Term	**1555**	4.00%	4.47%	7,410	7,410	4.00%	4.47%	3,250	10,661
Equity Ratio	**1555**	46.70%	8.57%	165,872	260,960	40.00%	8.57%	62,319	323,279
PIL Uplift	**1555**			78,057	122,805			29,327	152,132
Amortization (15 yrs)	**1556**		6.67%	296,431	450,150		6.67%	135,601	585,750
Incremental O&M	**1556**			0	0			207,723	207,723
Carrying Charges O&M / Amort	**1556**		2.09%	12,017	16,135		2.09%	4,597	20,733
Funding Through SM Adder	**1555**			(125,211)	(199,493)			(235,588)	(435,081)
Total				**559,215**	**850,288**			**269,331**	**1,119,619**
Capital	**1555**			**250,767**	**384,003**			**(78,590)**	**305,413**
O&M	**1556**			**308,448**	**466,285**			**347,921**	**814,206**

Smart Meter Capital and O&M - NTP

		2010 to Mar 31			
	USoA	**Additions and COC Split**	**Annual Factors**	**Annual Impact 1555/1556**	**Life to Date 1555/1556**
Smart Meter Additions -Current Year		335			
Life to Date Balance		610,612			
Amortization - Current Year		(10,174)			
Amortization - Life to Date		(94,198)			
Book Value Yr End		516,414			
Book Value Average		521,333			
Debt Ratio - Long Term	**1555**	56.00%	6.10%	4,452	258,874
Debt Ratio - Short Term	**1555**	4.00%	4.47%	233	10,894
Equity Ratio	**1555**	40.00%	8.57%	4,468	327,747
PIL Uplift	**1555**			2,103	154,234
Amortization (15 yrs)	**1556**		6.67%	10,174	595,924
Incremental O&M	**1556**			58,192	265,915
Carrying Charges O&M / Amort	**1556**		0.55%	233	20,966
Funding Through SM Adder	**1555**			(80,782)	(515,863)
Total				**(927)**	**1,118,692**
Capital	**1555**			**(69,527)**	**235,886**
O&M	**1556**			**68,600**	**882,806**

CLEARANCE OF SMART METER VARIANCE ACCOUNTS

Selection of Balances for Disposition

The Applicant used the OEB Model to establish fair recovery rates for each class. Table below summarizes the balances at March 31, 2010. NTP has chosen March 31 values because, with the exception of Smart Meter accounts, they are based on actual values reported with the March 2010 RRR submission.

Proposed Deferral/Variance/LRAM Recoveries

Account Description		Account #	Mar 2010 Balance
RSVA - Wholesale Market Service		1580	($327,313)
RSVA - One-time		1582	$26,390
RSVA - Retail Transmission Network		1584	$40,936
RSVA - Retail Transmission Connection		1586	($259,111)
RSVA - Power		1588	$1,045,409
LV Variance Account		1550	($40,478)
	Sub-Totals		$485,832
Other Regulatory Assets		1508	$51,880
Retail Cost Variance Account - Retail		1518	($611)
Retail Cost Variance Account - STR		1548	$12,395
Misc. Deferred Debits		1525	$2,357
Smart Meter - Capital		1555	$235,886
Smart Meter - OM&A		1556	$882,806
Approved Reg Assets		1590	($929,810)
Approved Reg Assets - 2008		1595	$996,037
	Sub-Totals		$1,250,941
LRAM		1525	$252,908
Total		Totals per column	$1,989,682

CALCULATION OF RATE RIDERS/ADDER - ALLOCATORS

Different allocators by customer classes are used for the recovery of the above balances. The following tables detail the allocators used by class and the conversion of the allocators to percentages:

Table of Allocators

2010 Data By Class	kW	kWhs	Cust. Num.'s (Average)	Dx Revenue $	Actual LRAM	Meter Capital Weighting from Cost Allocation	Previous Allocation $
Residential		274,854,374	29,370	9,926,666	235,753	5,169,120	1,165,021
GS<50		95,754,008	2,901	2,792,019	6,822	1,678,920	221,349
GS>50	788,495	313,112,560	401	4,388,428	10,333	529,368	239,578
USL		391,118	125	29,445			3,910
Sentinel Lights	850	306,233		16,508			1,111
Street Lights	14,582	5,355,339		315,800			4,888
Totals	**803,927**	**689,773,632**	**32,797**	**17,468,865**	**252,908**	**7,377,408**	**1,635,858**

Allocation %'s	kW	kWh's	Cust. Num.'s	Dist. Revenue	Actual LRAM	Cust. #'s w/ Rebate Cheques - GS only	Meter Weighting from CA Model	Previous Allocation (2008 EDR)
Residential	0.0%	39.8%	89.6%	56.8%	93.2%	93.2%	70.1%	71.22%
GS<50	0.0%	13.9%	8.8%	16.0%	2.7%	2.7%	22.8%	13.53%
GS>50	98.1%	45.4%	1.2%	25.1%	4.1%	4.1%	7.2%	14.65%
USL	0.0%	0.1%	0.4%	0.2%		0.0%		0.24%
Sentinel Lights	0.1%	0.0%	0.0%	0.1%		0.0%		0.07%
Street Lights	1.8%	0.8%	0.0%	1.8%		0.0%		0.30%
Totals	**100%**	**100%**	**100%**	**100%**	**100.0%**	**100%**	**100%**	**100%**

Allocation of Balances

The following table shows the distribution of the account balances by rate class using the allocators calculated above:

Distribution of Balances by Class

Regulatory Asset Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50	USL	Sentinel Lighting	Street Lighting	Total
WMSC - Account 1580	(327,313)	kWh	(130,424)	(45,437)	(148,579)	(186)	(145)	(2,541)	(327,313)
One-Time WMSC - Account 1582	26,390	kWh	10,516	3,663	11,979	15	12	205	26,390
Network - Account 1584	40,936	kWh	16,312	5,683	18,582	23	18	318	40,936
Connection - Account 1586	(259,111)	kWh	(103,248)	(35,970)	(117,620)	(147)	(115)	(2,012)	(259,111)
Power - Account 1588	1,045,409	kWh	416,564	145,123	474,548	593	464	8,116	1,045,409
LV Variance Account 1550	(40,478)	kWh	(16,129)	(5,619)	(18,375)	(23)	(18)	(314)	(40,478)
Subtotal - RSVA	**485,832**		**193,590**	**67,443**	**220,536**	**275**	**216**	**3,772**	**485,832**

Regulatory Asset Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50	USL	Sentinel Lighting	Street Lighting	Total
Other Regulatory Assets - Account 1508	51,880	Dx Revenue	29,481	8,292	13,033	87	49	938	51,880
Retail Cost Variance Account - Acct 1518	(611)	# of Customers	(547)	(54)	(7)	(2)	0	0	(611)
Retail Cost Variance Account (STR) Acct 1548	12,395	# of Customers	11,100	1,096	152	47	0	0	12,395
Rebate Cheques - Acct 1525	2,357	# cust. w/ Rebate Cheq	2,101	239	8	9	0	0	2,357
Smart Meter - Capital Acct 1555	235,886	# Metered Customers	165,278	53,682	16,926				235,886
Smart Meter - OM&A Acct 1556	882,806	# Metered Customers	618,555	200,905	63,346				882,806
Approved Reg Assets Acct 1590	(929,810)	Previous Allocation (2008 EDR)	(662,189)	(125,813)	(136,175)	(2,223)	(632)	(2,778)	(929,810)
Approved Reg Assets - 2008 Acct 1595	996,037	Previous Allocation (2008 EDR)	709,355	134,774	145,874	2,381	677	2,976	996,037
Subtotal - Non RSVA	1,250,941		873,133	273,122	103,157	300	94	1,136	1,250,941
Total to be Recovered (w/o LRAM)	1,736,774		1,066,723	340,565	323,693	575	310	4,908	1,736,774
LRAM	252,908	Actual LRAM	235,753	6,822	10,333				252,908
Deferral Accounts plus LRAM	1,989,682		1,302,477	347,387	334,026	575	310	4,908	1,989,682

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CALCULATION OF RATE RIDERS/ADDER - ALLOCATORS/ADDERS

The total dollars allocated to each class are then divided by the variable distribution statistic (kWh or kW depending on the class) to arrive at the class rate rider/adder.

The Applicant has chosen to clear these values over a two year period. NTP is also aware that the LRAM adder is normally applied over one year, but would prefer to be consistent with the Deferral period rather than have separate adders or bill impacts that fluctuate. Calculations are being provided for one and two year periods, but two has been used to calculate the bill impacts in Exhibit 8.

Calculation of Rate Riders/Adder

Alternative 1 (Preferred - LRAM recovered over 2 years with Deferral balances)

Deferral Account Rates (with LRAM)	Residential	GS < 50 KW	GS > 50 Non TOU	USL	Sentinel Lighting	Street Lighting
Billing Determinants	kWh	kWh	kW	kWh	kW	kW
Years for Recovery	2	2	2	2	2	2
Deferral Balances	0.00194	0.00178	0.20526	0.00074	0.18218	0.16828
LRAM	0.00043	0.00004	0.00655			
Total Rate Rider/Adder	0.00237	0.00181	0.21181	0.00074	0.18218	0.16828

Alternative 2 (LRAM recovered over 1 year, Deferral balances over 2 years)

Deferral Account Rates (w/o LRAM)	Residential	GS < 50 KW	GS > 50 Non TOU	Small Scattered Load	Sentinel Lighting	Street Lighting
Billing Determinants	kWh	kWh	kW	kWh	kW	kW
Years for Recovery	2	2	2	2	2	2
Deferral Rate Rider	0.00194	0.00178	0.20526	0.00074	0.18218	0.16828
LRAM Recovery						
Years for Recovery	1	1	1	1	1	1
LRAM Rate Adder	0.00086	0.00007	0.01310	N/A	N/A	N/A

Reconciliation of Rates to Balances

In the following tables, the rates calculated above are applied to the 2010 distribution variable statistics by class to calculate the expected recoveries:

Reconciliation of Rates to Balances

Alternative 1 (Preferred - LRAM recovered over 2 years with Deferral balances)

Annual Recovery of Deferral Accounts at 2010 Activity

Class	kWh	kW	Rate	Recovery
Residential	274,854,374		0.00237	651,238
GS<50	95,754,008		0.00181	173,693
USL	391,118		0.00074	288
GS>50		788,495	0.21181	167,013
Street Lights		14,582	0.16828	2,454
Sentinel Lights		850	0.18218	155
Annual				994,841
Recovery 2 Years				1,989,682

Alternative 2 (LRAM recovered over 1 year, Deferral balances over 2 years)

@ Proposed Rates with 2010 Statistics

Deferral Accounts

Class	kWh	kW	DA Rate	Recovery
Residential	274,854,374		0.00194	533,362
GS<50	95,754,008		0.00178	170,282
USL	391,118		0.00074	288
GS>50		788,495	0.20526	161,847
Street Lights		14,582	0.16828	2,454
Sentinel Lights		850	0.18218	155
Annual				868,387
Recovery 2 Years				1,736,774

LRAM

Class	kWh	kW	LRAM Rate	Recovery
Residential	274,854,374		0.00086	235,753
GS<50	95,754,008		0.00007	6,822
GS>50		788,495	0.01310	10,333
Recovery 1 Year				252,908
Total Recovery During Rate Period				1,989,682

Exhibit 10:

END OF APPLICATION