Festival Hydro INC.

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August 24, 2012

BY RESS & COURIER

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
TORONTO, ON M4P 1E4

Re: EB-2012-0124
Festival Hydro Inc. 2013 3rd Generation IRM Rate Application

Dear Ms. Walli,

Attached are two copies of Festival Hydro's Application for Electricity and Distribution Rates and charges effective May 1, 2013 (EB-2012-0167). Our filing is due August 30, 2012.

The enclosure consists of the Manager's Summary and the following related IRM 3 Work forms:

- 2013 IRM3 Rate Generator Model
- 2013 IRM3 Revenue Cost Ratio Adjustment Workform
- 2013 IRM3 RSTR Adjustment Workform
- 2013 IRM3 Shared Tax Savings Workform
- Incremental Capital Workform & Incremental Capital Project Model

The completed 2013 Rate Application and Workforms were submitted today via the Ontario Energy Board's RESS system.

If you have any questions please contact me at the number noted below or by email at bzehr@festivalhydro.com.

Yours truly,
Festival Hydro Inc.
ORIGINAL SIGNED BY W.G. ZEHR

W.G. Zehr, President
Tel (519) 271–4703 x. 243

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 Festival Hydro Inc. for an Order or Orders approving of fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2013.

Manager's Summary

Introduction

Festival Hydro Inc. "(Festival)" hereby applies to the Ontario Energy Board (the "Board") for an order or orders approving its proposed electricity distribution rates to be effective May 1, 2013, pursuant to Section 78 of the *Ontario Energy Board Act, 1998*.

The 2013 IRM application has been completed in accordance with the updated guidelines of Chapter 3 of the *Board's Filing Requirements for Transmission and Distribution Applications* dated June 28, 2012, the *Board's report on Electricity Distributors Deferral and Variance Account Review Initiative* issued July 31, 2009, and *Guideline G-2008-001 Electricity Distribution Retail Transmission Service Rates, Revision 4.0*, dated June 28, 2012.

Festival Hydro has utilized the Excel Workforms as provided by the Board. The individual models being filed as part of the IRM 3 Model include:

- 2013 IRM3 Rate Generator
- 2013 IRM3 Shared Tax Savings Workform
- 2013 IRM3 Revenue Cost Ratio Adjustment Workform
- 2013 IRM3 RTRS Adjustment Workform
- 2013 Incremental Capital Workform
- 2013 Incremental Capital Project Summary

Festival is not applying for a Renewable Generation Connection Funding adder or a Smart Grid Funding adder so the related Workforms are not being filed.

Festival Hydro distributes electricity to approximately 20,000 customers residing in the City of Stratford, and the surrounding towns of St. Marys, Seaforth, Brussels, Dashwood, Hensall and Zurich. Festival intends to publish the Notice of Application in the Stratford Gazette, which is a Stratford based no-paid subscription newspaper with a circulation of approx. 13,000 delivered to all households within the City. Festival will also publish the Notice in the St. Marys Journal Argus and the Seaforth Huron Expositor, both with a paid circulation of 3,400 and 2,050, respectively. This should provide adequate circulation coverage within Festival's service area.

This application has been filed in accordance with Canadian Generally Accepted Accounting Principles (CGAAP). Festival has not adopted IFRS, nor has it adopted Modified IFRS for RRR reporting purposes.

Festival plans to file a 2014 Cost of Service Application, with rates to be effective May 1, 2014.

May 1, 2013 Proposed Rate Adjustments

The May 1, 2013 proposed Tariff of Rates and Charges is presented in the attachments to this document. Festival seeks approval from the Board for a number of adjustments to its current rates approved effective May 1, 2012 (EB-2010-0167). It also seeks approval for the continuation of a number of existing rates and charges.

The requested adjustments\continuation of rates and charges are as follows:

1. Continuation of the current customer rate classes as approved in EB-2009-0263.

2. Approval of a price cap adjustment.

3. A Rate Rider for Tax Change to reflect changes in Federal and Provincial Rates as calculated in the Shared Tax Savings Workform.

4. Revenue to cost ratio adjustments in accordance with the Board's Decision and Order EB-2009-0263.

5. Continuation of the 2012 smart meter rate riders arising from Festival Hydro's smart meter disposition application (EB-2012-0260) currently before the Board. Festival is seeking smart meter rate riders (SMDRs and SMIRRS) to be effective November 1, 2012 and to continue for an 18 month period until April 30, 2013.

6. The continuation of the 2010 deferral and variance account rate riders as approved in EB-2009-0263.

7. Proposed adjustments to the existing retail transmission service rates (RTSR) as calculated in the RTRS Adjustment Workform.

8. Approval of a Rate Rider for Recovery of Incremental Capital Cost related to the costs associated with the construction build of a Transformer Station.

9. The continuation of existing Low Voltage Charges, Specific Service Charges, Retail Service Charges, Loss Factors, Transformer & Primary Metering Allowances and MicroFIT Generator Service Charge, as approved in EB-2009-0263.

10. Establish a Foregone Revenue Rate Rider in the event the Board is unable to provide a decision and order for rates effective May 1, 2013.

    Details to support the requested adjustments are provided in the Board IRM3 Work forms.

Supporting Documentation for Factors Impacting Proposed Rate Adjustments

Outlined below are the factors taken into consideration when determining the rate adjustments for which Festival Hydro is seeking approval effective May 1, 2013.

1. Price Cap Index Adjustment

Festival has used the IRM3 Rate Generator Model to calculate an interim price cap adjustment, which for Festival Hydro results in a net increase of 1.08%, calculated as follows:

Inflation Factor (GDP-IPI)	2.00%
Less: Productivity Factor	(0.72%)
Less: Stretch Factor	(0.20%)
Interim Price Cap Adj.	**1.08%**

Festival understands that the Board will update the price escalator in the Rate Generator model upon the publication of the 2012 GDP-IPI by Statistic Canada. Additionally, the Board will update the stretch factor should the groupings of the distributor-specific stretch factors be revised by the Board.

2. Changes in the Federal and Provincial Income Tax and Capital Tax Rates

The Board previously determined that the impact of currently known tax changes should be reflected in rates using a 50/50 sharing model.

In 2013, the overall corporate income tax rate is expected to increase from a statutory rate of 26.25% to 26.5%, in addition to a reduction for the first $500K of revenue as a CCPC. These tax changes create incremental tax savings of $170,671. The amount to be retained by Festival is $85,336.

Festival has used the IRM 3 Shared Tax Savings Workform to determine the resultant proposed rate rider for the period May 1, 2013 to April 30, 2014. In order to maintain a simplified and consistent approach, Festival proposes to apply the calculated rate riders proportionately across all customer classes based on Festival's 2010 COS determined distribution revenue by class.

3. ***Revenue to Cost Ratios Adjustments***

As part of Festival's 2010 Rate application EB- 2009-0263, Festival Hydro agreed to a systematic approach to mitigate outliers so all rate classes will be within the Board's targeted ranges by the end of the 2013 rate year.

Festival Hydro's 2010 COS Decision and Order EB-2009-0263 contains the following Board Decision: "The Board accepts the proposal to:

- Move the ratio for street light and sentinel light classes half way to the Board's lower target of 70% and move to ratios of 70% by 2012;
- Move the ratio of GS> 50 kW customers to 80%
- Move the ratio for USL customers to 120%
- A proposed revenue to cost ratio of 82.65% for Residential Hensall customers in 2010, and the proposed ratios for 2011, 2012 and 2013 noting that rate impacts for 250kWh customers will not exceed 10% in these three years."

As part of the 2011 IRM, Festival Hydro received approval from the Board in EB-2010-0083 to implement the first year phase of proposed adjustments. This first phase moved street lighting and sentinel lighting half way toward their 70% lower target; moved USL customers down to 120%, and Residential Hensall customers to 82.65%.

For the 2012 IRM rate year, the Board approved the 2nd year phase of adjustments. With the 2012 adjustments, both street lighting and sentinel lights reached the 70% minimum target, and Hensall Residential moved its second step closer to rate harmonization.

Revenue to Cost Adjustments as approved in EB-2009-0263
Change to be applied as part of 2013 IRM Application EB-2012-0167

Customer Class	2012 Adjusted Rev Cost Ratio per EB-2009-0263 (2010 COS)	2013 Proposed Rev Cost Ratio per EB-2009-0263 (2010 COS) (Column C)	2013 Adjusted Rev Cost Ratio per EB-2009-0263 (2010 COS) (Column D)	Difference from Board Approved EB-2009-0263 (Column D-C)	OEB Target Range
Residential	106.66%	106.27%	106.47%	-0.20%	85-115%
Residential - Hensall	99.00%	106.27%	106.27%	0.00%	85-115%
GS < 50 kW	112.03%	112.03%	112.03%	0.00%	80-120%
GS >50	81.31%	81.31%	81.31%	0.00%	80-180%
Large Use	112.03%	112.03%	112.03%	0.00%	85-115%
Sentinel Lights	70.00%	70.00%	70.00%	0.00%	70-120%
Street Lighting	70.00%	70.00%	70.00%	0.00%	70-120%
USL	120.00%	120.00%	120.00%	0.00%	80-120%

For the 2013 IRM rate year, the only outstanding revenue to cost adjustment required as per EB-2009-0263 is continuation towards harmonization of the Hensall residential rate. While the intent was for both Residential and Residential Hensall to have the same Revenue to Cost ratios by 2013, when the rebalancing is complete in the model, it results in a slight difference. The Residential ratio is at 106.47% compared to the Hensall Board approved rate of 106.27%.

Attached to this filing is the 2013 IRM Revenue to Cost Workform. In the Workform, Tab 14 generates a fixed service charge increase of $1.09 for Hensall. The $1.09 increase, along with the other changes created by the Rate Generator model, results in a Hensall Residential fixed service charge of $15.07, which is $.02 higher than the $15.05 service charge for remaining Residential customers. So that the fixed rate is the same for both rate classes, Festival has capped the Hensall Service charge adjustment at $1.05. The difference of $.02 for 413 customers over 12 months only totals $99.12, which Festival will choose to forgo in order for both Festival Residential and Hensall Residential to have the same Fixed Service charge of $15.05 per month. Festival requests that the Board approve the proposed revenue to cost adjustments for 2013 as provided in Column D in the table above.

Harmonization of Hensall Residential rates is being achieved through phased revenue to cost adjustments. As reported in the Board's Decision EB-2009-0263, the Board approved the "proposed ratios for 2012, 2013 and 2013 noting that the rate impacts for 250kWh customers will not exceed 10% in these three years." As illustrated in the rate impact table in the attached Appendix, distribution charges for a 250 kWh customers will be changing by 13.4% (total bill impact of 4.7% which is within the OEB's requirement.

As part of the 2014 COS rate application process, Festival plans to harmonize all rates being charged to Festival Residential and Festival Residential Hensall customers, so that there is one set of rates which apply to all residential customers.

4. *Smart Meter Funding Adder and Disposition Rider*

Festival filed a standalone Smart Meter Disposition application in May 2012 (EB-2012-0260) which is currently before the Board. Festival is seeking Board approval for smart meter rate riders (SMDRs and SMIRRS) to be effective November 1, 2012 and to continue for an 18 month period until April 30, 2014. Festival request the continuation of these Board approved rate riders from May 1, 2013 to April 30, 2014.

5. *Deferral and Variance Account Rate Riders*

Festival is requesting the Board consider the disposition of Group 1 Deferral and Variance Accounts, as outlined in detail below:

1. Group 1 Deferral and Variance Accounts

The report of the Board on *Electricity Distributor's Deferral and Variance Account Review Report* (the EDDVAR Report) provides that during the IRM period, a distributor's Group 1 audited account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is exceeded. As calculated on Tab 6 in the 2013 Rate Generator Model, Festival's net amount being requested for disposition totals $297,026 for Group 1 Deferral and Variance Accounts. According to the model, this claim does not meet the threshold test, so Festival's Group 1 Deferral and Variance Account balances are not eligible for disposition.

Tab 5 Deferral and Variance Account Continuity Schedule has been updated to reflect the approved and disposition of December 31, 2008 deferral and variance account as part of 2010 COS Application. Upon transfer of balances to Acct 1595, there were slight differences in the amount of interest projected compared to the amount projected in the 2010 COS model. These differences have been recorded in Column BN Adjustments during 2010- Other.

All December 31, 2011 ending principal and interest balances have been balanced and agree to Festivals RRR reporting (with the exception of Acct # 1562 PILs, which is explained below). Projected interest for 2012 and 2013 in the continuity schedule (Tab 5) has been calculated using the current prescribed rate of 1.47% .

2. USoA # 1521 Special Purpose Charge Variance Account

As part of Festival's 2012 IRM Rate Decision and Order dated April 1 2012, it states "the Board approves, on a final basis, Festival's request for the disposition of the principal and interest balances in Account 1521 totaling a debit of $7,216 over a one year period, from May 1, 2012 to April 30, 2013. The Board directs Festival to close Account 1521 as of May 1, 2012. For accounting and reporting purposes, the balance of Account 1521 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the Accounting Procedures Handbook for Electricity Distributors".

Festival confirms that the Board approved balance of $7,216 has been transferred effective May 1, 2012 to Account # 1595. To recover this cost, effective May 1, 2012, Festival implemented the Rate Rider for Deferral and Variance Account Disposition (2012). Festival expects full recovery when the rate rider expires April 30, 2013.

3. USoA Acct # 1562 Deferred PILs

As part of Festival's 2012 IRM Rate Decision and Order dated April 1 2012, it states "The Board approves the revised Account 1562 principal and projected interest balance as at April 30, 2012 of $271,992 consisting of a principal debit amount of $126,029 plus related debit carrying charges of $145,963. The Account 1562 debit balance is to be recovered over a one year period, May 1, 2012 to April 30, 2013. For accounting and reporting purposes, the balance of Account 1562 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the Accounting Procedures Handbook for Electricity Distributors."

On the Continuity Schedule Tab 5, the final approved PILS amounts do not agree to the December 31, 2011 balance reported on RRR. The RRR balance represented the December 31, 2012 PILs carry forward amount plus interest, which was based on the original PILS filings.

Festival confirms the Board approved Account 1562 principal and projected interest amount of $271,992 has been booked effective May 1, 2012 to Account # 1595. To recover this cost, effective May 1, 2012, Festival implemented the Rate Riders for Deferral and Variance Account Disposition (2012). Festival expects full recovery when the rate rider expires April 30, 2013.

4. Continuation of the 2010 Deferral and Variance Account Disposition(2010)

Festival requests the continuation of the 2010 Deferral and Variance Account rate riders to be collected over a remaining 1 year period, from May 1, 2013 to April 30, 2014, as approved in EB-2009-0263.

Continuation of 2010 Deferral and Variance Rate Riders

Customer Class	2010 Approved Deferral & Variance Rate Rider per EB-2009-0263	kWh/ kW
Residential	(0.00090)	kWh
Residential - Hensall	(0.00100)	kWh
GS < 50 kW	(0.00100)	kWh
GS >50	(0.35080)	kW
Large Use	(0.45070)	kW
USL	(0.00080)	kWh
Sentinel Lights	(0.38810)	kW
Street Lights	(0.27510)	kW

5. Smart Meter Entity "(SME)" Charge (EB-2012-0100)

The SME has applied to the Ontario Energy Board (the "Board") for approval of a SMC of $0.806 per Residential and General Service <50kW Customer per month. In the application, the IESO proposes to collect the SMC from all licensed electricity distributors ("Distributors") for the period July 1, 2012 to December 31, 2017.

Festival Hydro requests that when the SME Charge is approved by the Board, the Board also approve for Festival Hydro a rate rider equal to the SME Charge to be collected from all Festival Hydro's Residential and General Service < 50 kW customers. Festival requests the rate rider be approved for the same time period as is approved for the SME Charge recovery.

6. Lost Revenue Adjustment Mechanism (LRAM)

On April 26, 2012, the Board introduced new *Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037* for rate based application to recover revenue lost due to customer energy conservation, and to share in gains from effective CDM programs. For CDM programs delivered within the 2011 to 2014 term, the Board established Account 1568 as the LRAMVA to capture the variance between the Board-approved CDM forecast and the actual results at the customer rate class level.

The Guidelines state that Distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

Festival, with the assistance of Burman Energy Consultants, has completed a calculation of the LRAM amounts owing based on the OPA 2011 draft Annual Results Report issued August 1, 2012. The amount owing based on the preliminary results total $41,286. Since Festival does not deem this to be a significant amount, Festival will defer its LRAM claim until our 2014 COS filing.

The amount of $41,286 is based on the OPAs preliminary results. The LRAM claim in Festival's 2014 COS application will be based on the actual OPA 2012 Annual Results, which Festival expects will be higher as there are additional projects identified to be included I the OPAs final report.

The LRAMVA balance of $41,286 has not been included in Tab 5 Continuity Schedule because it is preliminary. Festival will include the LRAMVA balance on its quarterly RRR reports once the amount has been determined based on the final OPA Results Report.

6. ***Transmission Network and Connection Rate (RTRS) Adjustments***

Festival has followed *Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates – version 4.0* when completing the Board's supplied 2013 IRM3 RTRS Adjustment Workform. Festival requests that the proposed adjustment in the table below be approved by the Board, with the understanding that the Uniform Transmission rates (RSTRs) used in the IRM 3 Workform may be subject to update by the Board in the event the Uniform Transmission Rates are

The kWh amounts reported in model agree to the RRR filing (E. 2.1.5 Customers, Demand and Revenue) of 582,557,314 kWh. In addition, the dollar amounts for Network and Connection Charges in the model agree to the December 31, 2011 balances as reported for USoA accounts # 4714 Network Charges and #4716 Connection Charges in the RRR 2.1.7 Trial Balance.

The proposed RTRS rates for all rate class have decreased from 2012 because of a reduction in the proposed rates being charged by the IESO and Hydro One effective January 1, 2013. The tables below provides a comparison of the 2012 existing RTRS approved rates (per EB-2011-0167) to the 2013 proposed rates as determined by the model:

Proposed Transmission Network Rates

Customer Class	2012 Approved Network Rate per EB-2011-0167	2013 Proposed Network Rate	Decrease in Rates	kWh/kW	% Decrease
Residential	0.0067	0.0061	(0.0006)	kWh	-9.0%
Residential - Hensall	0.0067	0.0061	(0.0006)	kWh	-9.0%
GS < 50 kW	0.0058	0.0053	(0.0005)	kWh	-8.6%
GS >50 kW	2.4342	2.2145	(0.2197)	kW	-9.0%
GS >50 kW, Interval Metered	2.5854	2.3520	(0.2334)	kW	-9.0%
Large Use	2.8627	2.6043	(0.2584)	kW	-9.0%
USL	0.0058	0.0053	(0.0005)	kWh	-8.6%
Sentinel Lights	1.8451	1.6785	(0.1666)	kW	-9.0%
Street Lights	1.8358	1.6701	(0.1657)	kW	-9.0%

Proposed Transmission Connection Rates

Customer Class	2012 Approved Network Rate per EB-2011-0167	2013 Proposed Network Rate	Decrease in Rates	kWh/kW	% Decrease
Residential	0.0050	0.0048	(0.0002)	kWh	-4.0%
Residential - Hensall	0.0050	0.0048	(0.0002)	kWh	-4.0%
GS < 50 kW	0.0045	0.0044	(0.0001)	kWh	-2.2%
GS >50 kW	1.7981	1.7422	(0.0559)	kW	-3.1%
GS >50 kW, Interval Metered	1.9712	1.9099	(0.0613)	kW	-3.1%
Large Use	2.2542	2.1841	(0.0701)	kW	-3.1%
USL	0.0045	0.0044	(0.0001)	kWh	-2.2%
Sentinel Lights	1.4192	1.3751	(0.0441)	kW	-3.1%
Street Lights	1.3901	1.3469	(0.0432)	kW	-3.1%

7. *Rate Rider for Recovery of Incremental Capital Cost*

Festival Hydro requests approval for a rate rider to recover amounts through rates related to non-discretional, incremental capital investments for a new municipal transformer station in the City of Stratford. Festival Hydro requests the Board deem the new transformer station to be a distribution asset under Section 84 (a) of the *OEB Act* in order that Festival may recover the revenue required through distribution rates. This part of the Application has been prepared in accordance with the requirements of Chapter 3 of the Filing Requirements for Transmission and Distribution Applications ("**Chapter 3**"), section 2.2. The amounts included in this ICM were not included in Festival Hydro's 2010 Cost of Service rate application.

Festival Hydro submits that these incremental capital investments meet the eligibility criteria to be considered for recovery prior to rebasing. The amount exceeds the materiality threshold, it has a significant influence on the operation of Festival Hydro, and the cost is non-discretionary and outside the existing rate base and it represents the most cost effective solution for ratepayers. In addition, the expenditure will provide benefit to Hydro One Networks Inc. at the existing Stratford TS.

The new municipal transformer station is scheduled to be in-service by April 30, 2013 and will alleviate a potential overload condition at the existing Hydro One owned Stratford TS that provides the sole supply to the City of Stratford and the surrounding area. Festival Hydro has been exceeding its "assigned capacity" at the shared Stratford transformer station during the summer months for most of the past five years. It is likely Festival Hydro will continue to exceed its "assigned capacity" on a regular basis until the new municipal transformer station is constructed. If load continues to increase as most recently forecasted, by 2014 a failure of a single major component at the existing Stratford TS during peak loads could result in rotating blackouts for the City of Stratford and surrounding area. As load in Stratford continues to grow, the likelihood of rotating blackouts will also increase. In addition to adding capacity, the new municipal transformer will eliminate low voltage issues at the end of the longest feeders and significantly improve reliability for all customers in Stratford.

Materiality:

ICM Threshold

In order to qualify for ICM, the amount must meet the materiality threshold prescribed by the Board and incorporated into the Board's most recent IRM 3 Incremental Capital Work Form- Version 1.0 issued on July 27, 2012. Tab E2.1 of the Work Form (shown below) indicates the threshold for Festival Hydro is $3,642,654. The 2013 Incremental Capital Work Form- Version 1 and the 2013 Incremental Capital Project Summary- Version 1.0 are filed in the appendices.

Threshold Test

Year		**2010**	
Price Cap Index		**1.08%**	**A**
Growth		**-0.33%**	**B**
Dead Band		**20%**	**C**
Average Net Fixed Assets			
Gross Fixed Assets Opening		$ 73,469,244	
Add: CWIP Opening		$ 3,357,000	
Capital Additions		$ -	
Capital Disposals		$ -	
Capital Retirements		$ -	
Deduct: CWIP Closing		$ -	
Gross Fixed Assets - Closing		$ 76,826,244	
Average Gross Fixed Assets		$ 75,147,744	
Accumulated Depreciation - Opening		$ 41,462,401	
Depreciation Expense		$ 2,787,375	**D**
Disposals		$ -	
Retirements		$ -	
Accumulated Depreciation - Closing		$ 44,249,776	
Average Accumulated Depreciation		$ 42,856,089	
Average Net Fixed Assets		$ 32,291,656	**E**
Working Capital Allowance			
Working Capital Allowance Base		$ 52,239,484	
Working Capital Allowance Rate		15%	
Working Capital Allowance		$ 7,835,923	**F**
Rate Base		**$ 40,127,578**	**G = E + F**
Depreciation	**D**	**$ 2,787,375**	**H**
Threshold Test		**130.68%**	**I = 1 + (G / H) * (B + A * (1 + B)) + C**
Threshold CAPEX		$ 3,642,654	**J = H *I**

In the 2010 COS application, Festival Hydro projected capital spending in 2011 and 2012 to be around $3.4 million each year, with similar annual amounts for 2013 to 2016. Festival Hydro estimates that capital spending on the Transformer station, which spans from 2010 to 2013, to be $15,863,113. This amount added to the 2013 budgeted capital amount of $3,489,000 results in a total spend of $19,352,113. The amount which is beyond the Board-defined materiality threshold amount has been included in the models, reduced by 50% to reflect the fact that Festival's 2013 IRM is one year preceding our next cost of service scheduled for 2014.

Year	Capital Spending Forecast	Capital Spending Actual (per E2.1.5 PBR Gross Capital)
2009	$3.352,000	$3,996,565
2010	$3,507,000	$4,060,804
2011	$4,595,735	$3,621,283
2012	$13,870,800	N/A
2013	$7,540,480	N/A

The capital work planned for 2013 is the continuation of planned replacements of end of life assets, reliability improvements, and voltage conversions. Details regarding 2013 projects are provided in the Appendices. All proposed Capital work is considered non-discretionary spending and cannot be deferred. Further, deferral of any projects would impact the safety, reliability, and efficiency of the distribution system, and would result in higher capital expenditures in subsequent years.

While construction on the TS has commenced in 2012 with spending to date being approximately $1.7M, the costs during construction are being recorded in the CWIP account[1]. Upon project completion, the eligible ICM amounts will be transferred to Account 1508, Other Regulatory Asset, sub-account Incremental Capital Expenditures, as per 2.2.7 ICM Accounting Treatment outlined in Chapter 3 of the Filing Requirements for Electricity Transmission and Distribution Applications dated June 28, 2012.

[1] Land for the TS was purchased in late 2010 and engineering work took place during 2011.

Festival Hydro MTS #1 - Capital Spending Forecast

	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast	Total
Engineering, Design, Legal		$ 300,730	$ 689,412	$ 350,000	$ 1,340,142
Power Transformers			$ 2,572,950	$ 454,050	$ 3,027,000
Switchgear			$ 1,236,420	$ 65,080	$ 1,301,500
Substation Equipment				$ 185,350	$ 185,350
Civil Including Building, Foundations, Ductbanks			$ 5,410,350	$ 2,041,296	$ 7,451,646
Electrical Work			$ 611,685	$ 269,069	$ 880,754
Land	$ 879,452				$ 879,452
Capital Contribution		$ 12,000		$ 588,000	$ 600,000
Sub-Total	$ 879,452	$ 312,730	$ 10,520,817	$ 3,952,845	$ 15,665,844
CWIP Interest Expense			$ 98,635	$ 98,635	$ 197,270
Total		**$ 312,730**	**$ 10,619,452**	**$ 4,051,480**	**$ 15,863,114**

Construction of the new transformer station started in April 2012 and is expected to be in service by the end of April 2013. This assumes that Hydro One will be able to complete the 230 kV connections and associated work prior to this date.

Festival Hydro has selected the option that is the lowest cost while still providing the long term capacity and reliability required for the customers in Stratford.

Existing System Details

The Stratford TS, which is owned by Hydro One, provides the only supply to the City of Stratford and its approximately 15,000 residents and businesses. In addition to supplying Festival Hydro's customers, the Stratford TS supplies Hydro One customers in the rural area surrounding Stratford, and embedded LDCs to the north and south. A single line diagram showing the 27.6 kV distribution feeders in Stratford is included in the Appendices. The Stratford TS is in the northeast corner of the City shown as a rectangle labelled TS.

There are no other distribution supply points in close proximity to Stratford capable of providing a reliable supply point for the City of Stratford. The two closest potential supplies are: (i) St. Marys TS and (ii) Seaforth TS. The St Marys Transformer Station is approximately 16 km from Stratford but the distribution voltage is 13.8 kV while Stratford is 27.6 kV. The nearest 27.6 kV supply point is the Seaforth TS which is approximately 40 km from Stratford, and this distance makes it impractical for use as a reliable supply point for Stratford load.

The Stratford TS was originally constructed approximately 75 years ago. While this location may have been ideal at that time, the actual growth and expansion of the City has been in a southwesterly direction. Most significant growth will occur in the southwest part of the City.

The growth to the southwest has resulted in two long feeders that have large industrial loads at the far end. The longest of these feeders, the 68M2, is over 7km in length and frequently carries load in excess of Festival Hydro's normal peak feeder load of 15 MW[2]. Since 2009, the 68M2 had monthly peaks in excess of 17 MW for most months of the year. Since this is the only feeder available in the southwest section of the City, all new load in this area is connected to this feeder which continues to increase the load. Switching new load to other feeders is not an option.

The long feeders have two major drawbacks – the long feeders have a greater exposure to system outages caused by animals, trees, weather, and vehicles, and during heavy loads, the customers at the end of the feeder will frequently have lower than expected voltage. As a result, the customers at the ends of these feeders experience a higher than average number of outages[3] and will frequently complain of low voltage during peak load.

To mitigate the voltage complaints, capacitor banks were installed on the feeder in 2009. While this improved the voltage in 2009 and 2010, customer complaints returned in 2011 and 2012 during times when the feeder was at higher than normal load due to system reconfiguration to accommodate work at the Stratford TS or within the distribution system. The voltage measured at the customer demarcation point during these high load periods is within industry guidelines (+ or – 5% of nominal), but some of our industrial customers have issues operating some of their equipment at the lower end of this scale[4].

Supplying the entire City and the surrounding rural area from a single transformer station has operational challenges that impact reliability and quality of supply to all customers connected to the existing TS. During planned or unplanned maintenance work at the TS, it is frequently necessary to de-energize half the station. While half the station is unavailable for use, load is transferred to the other half and feeder breakers carry twice their normal load and in some cases, are shared between Hydro One and Festival Hydro. Outages that occur on the transmission circuit during this time period (even momentary ones) result in outages to all customers supplied by this station. An outage to one feeder during this time period affects twice as many customers and all customers will typically experience a voltage dip. The loss of a feeder breaker during this time period can result in a long outage to a large number of customers as there is insufficient capacity on any remaining feeder to carry another feeder and load must be shifted to the remaining feeders in smaller pieces to avoid overloading a feeder breaker. As load continues to grow, the window for scheduling planned maintenance during low load periods decreases and customers are at greater risk for more frequent and longer outages as well as poorer power quality. During the past five years, there have been several instances of these

[2] Normal peak load is 15 MW or 314 Amps per phase. This allows one feeder to carry the load of another feeder during planned and unplanned outages without exceeding the maximum loading of 30 MW.

[3] FHI's 2011 System Reliability Report, included in the Appendices, shows the 68M2 feeder has higher than average SAIDI, CAIDI, and SAARI based on performance from 2007 to 2011.

[4] The most recent voltage complaint occurred on July 17, 2012 from a customer at the end of the feeder. Load on the feeder was 50% higher than normal due to switching required for a capital project and the customer was unable to operate some equipment for several hours until the switching returned to normal.

scenarios occurring which has resulted in complaints from customers regarding the decrease in reliability and power quality. In some cases, Hydro One has had to defer planned work as Festival Hydro was concerned that the operational risk was too great. As such, in those situations, it was necessary to wait until the load had decreased (typically on weekends or holidays).

Most of the existing load in the southwest area of Stratford is industrial and almost all of the vacant land is also zoned industrial. It is anticipated that existing customer load will increase as certain industries recover from the 2008/09 downturn. Of note, the auto plants in Ingersoll, Woodstock, and Cambridge, which are major customers of some of these industries, have made public announcements about increasing production. The City of Stratford has expressed concern that outage frequency and voltage issues are impacting the City's ability to retain and attract industrial customers to Stratford (see City of Stratford Economic Development Letter in the Appendices). With the existing customers returning to more historical loads, this situation would have deteriorated but for the construction of the new municipal transformer station.

History and Monitoring of the Issue

Festival Hydro and Hydro One and their predecessors (Stratford PUC and Ontario Hydro) have been monitoring the situation for more than 20 years. The construction of a second transformer station in the southwest end of Stratford where most of the new load was being planned and developed was identified as the best long-term solution in 1991. The need for the new transformer station has been deferred through switching load off the Stratford TS and reductions in demand. Simply put, Festival Hydro has run out of temporary fixes and must implement the long-term solution.

Load forecasting in 1989 projected that the Stratford TS would be overloaded as early as 1992/93. The actual load growth was much less than expected and Ontario Hydro permanently shifted the load in Mitchell from the Stratford TS to the Seaforth TS to provide additional capacity in Stratford. At that time, the economy slowed significantly which impacted demand.

The ultimate, long-term solution identified in 1991 was the construction of a second transformer station in the southwest end of Stratford where most of the new load was being planned and developed. (See *1991 Planning Report in the Appendices*) In addition to alleviating the overload condition, the second transformer station, if located in the southwest section of the City, would also alleviate the low voltage and high outage frequency experienced by the customers in the southwest section of Stratford. It would mitigate and in some cases eliminate the reliability and power quality issues related to the limited capability of performing planned maintenance at a single TS.

In 2004, Hydro One issued a brief summary report on the Stratford TS, noting that capacity would be exceeded by 2010 (*see 2004 LTR Study in the Appendices*).

Since 2004, the loading on the Stratford TS was carefully monitored and in 2008, Festival Hydro received notice of a planned development that would add at least 10 MVA of load to the system by 2014. At that time, with only 4 MVA of available capacity this new customer and other expected load growth would cause an overload at the Stratford Transformer Station by 2011 (see 2008 December Meeting Minutes in the Appendices).

In 2009, the following options were considered to alleviate the impending overload condition:

1. ***Replace Existing TS with Larger Unit.*** Hydro One indicated that one of the transformers at the existing transformer station could be replaced with a larger unit which would increase the total station capacity by 16 MVA. The cost of this transformer replacement was estimated to be around $3.5 million. This increase in capacity would be adequate until approximately 2015 based on the medium load growth forecast provided by Hydro One (see 2009 Hydro Load Forecast in the Appendices). However, the location of this new customer would require Festival Hydro to connect it the already overloaded 68M2 feeder. The nearest alternate feeders, the 68M3, 68M4, and 68M5, were also at or near the maximum normal load of 15 MW so extending any of these three feeders to this area would not solve the feeder loading problem. To supply this new load and future load growth in the area would require Festival Hydro to construct a new distribution feeder through the City at a cost of at least $3.5 million[5], bringing the total cost to at least $7 million. This option would not eliminate the existing voltage issues at the end of the feeder, and the new feeder would only make a minor improvement in the outage frequency. Also, the load growth forecast at the time indicated that even with the additional 16 MVA provided by the replacement transformer, the transformer station would be overloaded in 2015 at which time other options for adding capacity would need to be considered.

2. ***Hydro One Construction of New TS.*** Festival requested information from Hydro One on the construction of a second transformer station in the southwest end of the City where the majority of the new load was being located. The City of Stratford had plans for the development of a 50 acre industrial park around the existing 230 kV double circuit transmission line, making it an ideal location for a new transformer station. Hydro One provided illustrative examples of costs to build a new transformer station which ranged as follows according to four most likely configurations (see 2008 June Planning Meeting Minutes in the Appendices):

    1. Single 230 kV connection, single 25/41 MVA transformer with 4 feeders = $14 million.

[5] Budget estimates for a new feeder constructed through an urban area range from $500,000 to $1 million per kilometre, depending on the amount of underground distribution required. A 7km feeder to supply this area would cost between $3.5 million and $7 million.

2. Single 230 kV connection, single 50/83 MVA transformer with 8 feeders = $16 million.
3. Dual 230 kV connections, two 25/41 MVA transformers with 4 feeders = $19 million.
4. Dual 230 kV connections, two 50/83 MVA transformers with 8 feeders = $21 million.

Based on a load forecast prepared by Festival Hydro, Hydro One estimated that the capital contribution required from Festival Hydro would be approximately $14 million for a new transformer station with a single 230 kV connection and a single 50/83 MVA transformer (configuration number 2 above). Hydro One did not foresee any significant load growth within their service territory supplied by the Stratford Transformer Station, and therefore advised that they had no interest in sharing the new transformer station. Potential sites for the new transformer station were reviewed and narrowed down to four parcels abutting the existing 230 kV dual transmission line in the southwest end of Stratford. All four sites had the benefit of being located close to the proposed 10 MW new customer and future industrial load growth. They were also in close proximity to existing 27.6 kV distribution circuits which meant only minimal investment in feeder extensions were required to connect over 50 MVA of capacity. Locating the new transformer station near the industrial loads meant that the longest feeders would be shortened significantly, which would eliminate the voltage issues and improve reliability for all Stratford customers.

3. ***Festival Hydro to Construct New TS.*** In addition to considering a second transformer station constructed by Hydro One, Festival Hydro obtained estimates from two contractors to construct a comparable transformer station for around $10 million (see TS Budget Quotes 2009 in the Appendices). The transformer station design as quoted by the two contractors would be essentially the same as the proposal presented by Hydro One, and would have the same benefits in addressing the capacity, feeder loading, voltage issues, and reliability improvements. While the construction cost provided by the contractors was considerably lower, Festival Hydro understood that owning a transformer station meant additional obligations that would incur on-going costs associated with operations and maintenance. Using data obtained from other LDCs who own their own transformer stations, it was calculated that the net present value of 30 years of future operating and maintenance costs would be approximately $1.1M[6]. The total value of this option was $11.1M.

With the first option, it was recognized that it would only defer the need for a second transformer station until approximately 2015 and it did not adequately address the voltage and reliability issues. Therefore, it was decided to examine four of the most likely scenarios: (i) Hydro One upgrades the one transformer at the existing TS in 2010 to meet the immediate capacity requirement, then Hydro One builds a second TS in 2015 to

[6] This excludes a catastrophic failure of a power transformer.

provide the long term capacity; (ii) Hydro One upgrades the one transformer at the existing TS in 2010 to meet the immediate capacity requirement, then Festival Hydro builds a second TS in 2015 to provide the long term capacity; (iii) Hydro One builds a second TS in 2010 to meet the immediate and long term capacity requirement; and (iv) Festival Hydro builds a second TS in 2010 to meet the immediate and long term capacity requirement. A simple net present value calculation was used to compare the three options noting that option 1 required either option 2 or 3 in 2015. The table below summarizes the different scenarios that were reviewed and the merits of each.

Scenario	NPV[7]	Address Capacity Issue?	Address Voltage Issue?	Address Reliability Issue?
Hydro One Replaces One Transformer at Devon TS in 2010, Festival Builds New Feeder in 2010, Hydro One Builds Second TS in 2015	$16.8M	yes	Not until 2015	Minimal until 2015
Hydro One Replaces One Transformer at Devon TS in 2010, Festival Builds New Feeder in 2010, Festival Hydro Builds Second TS in 2015	$14.7M	yes	Not until 2015	Minimal until 2015
Hydro One Builds Second TS in 2010	$13.3M	yes	yes	Yes
Festival Hydro Builds Second TS in 2010	$10.5M	yes	yes	Yes

The solution chosen, of the four scenarios considered, was the one with the lowest net present value that addresses all the issues is a second transformer station built by Festival Hydro. Subsequently, a financial analysis[8] concluded that the rate impact to customers would be less with the Festival Hydro owned solution than with a comparable Hydro One owned solution. This analysis is consistent with the conclusion reached by other Ontario LDCs in similar circumstance, many of whom were consulted during this process.

During 2009, load in Stratford decreased somewhat due to overall economic conditions and conservation activities. This deferred the potential overload at the existing transformer station by about two years to 2013 or 2014. As a result, the decision to move forward on this project was deferred until 2010.

On October 1, 2010, the Festival Hydro Board of Directors authorized staff to proceed with the construction of a new transformer station, with a targeted in-service date of July 1, 2013, and to be owned and operated by Festival Hydro. At this time, the Board authorized the conditional purchase of property adjacent to the 230 kV line, and the

[7] A discount rate of 5.5% was used. Adjusting the discount rate from a low of 2.5% to a high of 7.5% made no difference in the relative ranking of the scenarios.
[8] The rate impact analysis was part of the information used by Festival Hydro's Board of Directors to make the decision to proceed in October 2010. See FHI Board Report TS Decision Oct 2010 in the Appendices.

commencement of an Environmental Assessment. (See FHI Board Report TS Decision Oct 2010 in the Appendices)

In 2010, following a competitive RFP process, Festival Hydro retained RJ Burnside and Associates to conduct an environmental assessment as required by O. Reg. 116/01 Electricity Projects. Burnside concurred with the site selected by Festival Hydro. The EA process did not identify anything that would prevent the construction of a transformer station on the selected property. The final EA report was issued in January 2011.

In early 2011, Festival Hydro issued an RFP to obtain the services of a third party consultant to review the findings to date, and provide advice on the best way to proceed – including technical details regarding the new transformer station. Costello & Associates was retained in March 2011 and asked to provide a report by June 2011.

The final report from the consultant issued in August 2011 (see Festival Hydro Final Report on TS Supply Options Final Version in the Appendices[9]) concluded that the load forecast prepared by Festival Hydro was consistent with typical utility practices, a new transformer station is required to meet load growth, and Festival Hydro should design, construct and operate a new 230 kV DESN transformer station sized to meet the highest load forecast and using GIS-type switchgear[10] The only significant deviation from Festival Hydro's original conclusion was that the consultant recommended that, for reasons of improved reliability and long term capacity, the new transformer station should be a full DESN with two 230 kV connections and two transformers[11]. The budget price prepared by the consultant suggested a cost of approximately $12.9 million (excluding the cost of land), which was still less than Hydro One's estimate $19 million for a similar station.

A final review of the load forecast for Stratford took place to determine the latest possible time that the new TS should be in service to ensure adequate supply would be available to meet the forecasted demand. At that time (summer of 2011), it was determined that the forecast created in 2010 for new load[12] was still applicable, although the actual peak load was approximately 1 to 2 MW less than predicted due to an industrial customer unexpectedly closing. This meant that the existing TS would not be in an overload situation until 2015 assuming medium growth. However, it was recognized that several industrial customers who had decreased load in 2009 and 2010 were in a position to return to previous load levels as the auto industry and overall economy recovered. As most of these customers had all the equipment in place to return to previous production levels, there was a very real possibility of their loads increasing relatively quickly in which case the existing TS could be overloaded as soon as 2013 assuming the high

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[9] Some information deemed to be confidential has been redacted or removed from the Report by Costello & Associates. The majority of the confidential information consists of preliminary budgetary figures from specific vendors of equipment and services. If requested by the OEB, an unredacted version will be filed with the Board Secretary.
[10] see page 28 of the Costello report
[11] section 5.1 page 16 of the Costello report
[12] See Appendix 1 of the Costello report

growth estimate[13]. With the majority of these customers on the M2 feeder, there was a concern that the loss of the M2 feeder breaker would mean an extended outage to a large group of industrial customers (since the amount of load on the M2 feeder could not be transferred in its entirety to either of the adjacent feeders and load would need to be spread over several feeders). Knowing that the construction of a new TS takes approximately 18 to 24 months, and that there was a real possibility of load exceeding capacity as early as 2013, it was determined that the in service date of April 2013, which was approved by the FHI Board in October 2010, was still a valid target[14].

An RFP was issued for Engineering Services and the consultant retained in turn issued RFPs for the power transformers, switchgear, and general contractor. The transformers were ordered in November of 2011 and the switchgear ordered in March of 2012. The general contractor was hired in May of 2012.

In July of 2012, with over 90% of the work awarded, the budget was revised to $15.9 million including the cost of land. This amount is approximately $2 million higher than Costello's estimate as it includes the cost of land and reflects actual pricing and unforeseen extras such as poor soil resistivity requiring additional grounding and additional site grading required for site plan approval. The capital contribution amount of $600,000 is an estimate of the amounts payable to Hydro One for the connection to the two 230 kV circuits. The actual amount for this portion of the project will not be known until Hydro One completes the connections in 2013.

Incremental Capital Rate Rider

Festival Hydro requests the approval of an incremental rate rider to recover an incremental revenue requirement of $672,412, as calculated on Tab E4.1 of the Incremental Capital Workform. There are no revenue requirement offsets from revenues being generated through other means, such as customer contributions. The incremental revenue is not being recovered, in full or in part, through the existing rate base.

Festival Hydro is scheduled to submit a cost of service rate application in 2014 and therefore pursuant to Chapter 3, section 2.2.3, the half year rule is applicable. . In the Incremental Capital Project Workform, on the Incremental Capital Summary Page, the capital costs have been entered at 50% of the total costs, which generates 50% of the amortization and CCA values. Likewise, the 50% rule has been reflected in the Incremental Capital Workform on E.1.3 Summary of IC Projects.

[13] See FHI Load Forecast 2011 in the Appendices. LTR is exceeded in 2015 with medium growth and 2013 with high growth.
[14] See Newspaper Clippings in the Appendices for articles from July 2012 and August 2012 showing continuing recovery of the auto sector which is expected to result in load increases for several Stratford based suppliers.

Festival requests the Board approve the recovery of the incremental revenue requirement through Option A, which allows for the collection of a combined fixed service charge and distribution volumetric charge. Festival prefers Option A over Option B – Variable as Option A assists in maintaining Festival's existing fixed to volumetric charge ratio. The table below provides the proposed rate riders for each rate class. Festival request this rate rider be in effective from May 1, 2013 to April 30, 2014.

Festival plans to file a 2014 COS application. At that time Festival will file a calculation of the amounts to be incorporated into the rate base.

	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kW Rate Rider M = F / J
Residential	0.99173	0.00110	
Residential - Hensall	0.75371	0.00081	
General Service Less Than 50 kW	1.95319	0.00098	
General Service 50 to 4,999 kW	14.80594	-	0.15181
Large Use	718.88332	-	0.06671
Unmetered Scattered Load	0.84717	0.00084	
Sentinel Lighting	0.09480	-	0.49748
Street Lighting	0.05177	-	0.23442

In *Chapter 3 of the Filing Requirements for Electricity Transmission and Distribution Applications dated June 28, 2012*, the Board request LDCs to describe the actions the distributor will take in the event that the Board does not approve the ICM application. Festival's plan is to proceed with the project as planned. There is an immediate need in terms of meeting future load growth. There are immediate benefits to our customers in terms of improved reliability. For these reasons, Festival will be proceeding as planned.

Festival is funding this project with long term (25 year) financing from a financial institution. There will be prime-based interim borrowing during the construction phase. Upon project completion, the interim funding will be converted to long term fixed rate financing.

Festival issued an RFP for financing of the TS in the spring of 2012. There were seven prospective lenders who replied to the RFP, and made oral presentations to Festival Hydro's Senior Management. Criteria were established to evaluate and select the preferred lender. Festival is currently in final negotiations with the selected vendor to finalize the lending agreement and establish a future-dated the long term rate.

Consequences if Rate rider not Approved

If the rate riders were not approved, it would cause further carrying costs to Festival Hydro in terms of additional interest expense. In the short term, Festival has sufficient borrowing capacity to carry out its capital plan. However, in the long-term, disapproval or deferral of approval may have significant impacts on future borrowing costs.

The underlying principle of matching the time period in which benefits are derived to costs incurred supports Festival Hydro's request to the Board to approve to collect distribution revenues through an Incremental Rate Rider effective May 1, 2013. Since customers will receive immediate benefit from the new TS, it supports matching Festival's cost recovery to commence during the same period.

8. ***Outstanding Board Directives***

Festival filed a Cost of Service "(COS)" rate application effective May 1, 2010 (EB-2009-0263), resulting in rates being approved by the Board and implemented as of that date. Festival has complied with all of the Board Findings and Directives as presented in the Decision and Order issued April 1, 2010 (EB-2009-0263). The only remaining EB-2009-0263 Directive matter relates to Revenue to Cost ratio adjustments. In 2011 and 2012, the 1st two phases of Revenue to Cost ratio adjustments were completed under EB-2010-0083 and EB-2011-0167. The remaining phase, related to Hensall Residential rates, is being completed as part of this application.

In Festival Hydro's 2012 Decision and Order EB-2010-0083, with regard to a separate rate rider for Global Adjustment applicable to non-RPP customers only, the Board directed Festival Hydro as follows:

"The Board notes that Festival Hydro received approval from the Board in its 2010 IRM decision (EB-2009-0263) to collect the 2008 global adjustment sub-account balance from all customers due to Festival Hydro's inability to charge a separate rate rider to non-RPP customers only. The Board stated that Festival Hydro should "make efforts to determine the cost of system enhancement and provide this information in a future rate application. In response to Board staff interrogatories, Festival Hydro indicated that it has not made any progress to implement a separate rate rider that would prospectively apply to non-RPP customers, as stipulated by the Board.

Festival Hydro confirms with the Board that it is now capable of applying the Global Adjustment rate rider to only those customers who are subject to the global adjustment (i.e. low-volume customers who purchased their electricity through a licensed retailer and all other customers who are not low-volume customers). However, Festival is not requesting disposition of the Global Adjustment Account (Sub account # 1588) in this application due to materiality limits.

9. *Continuation of Rates and Charges approved effective May 1, 2012 under EB-2009-0263*

Festival requests the Board's approval for the continuation of the following rates and service charges, which were first approved as part of EB-2009-0263. Festival has reviewed these rates and charges as part of the 2013 IRM application and has determined there is no need to request a change at this time. These rates have been used in preparation of the 2013 IRM Rate Generator model.

Continuation of the following rate and charges are requested:

- Low Voltage Charges
- MicroFIT Generator Service Charge of $5.25 monthly
- Standard Supply Administration Charge of $0.25
- Specific Service Charges
- Retail Service Charges
- Loss Factors
- Transformer and Primary Metering Allowances

In addition, continuation of the Wholesale Market and Rural Rate Assistance Charges as approved as part of Festival's 2012 IRM Rate application.

Proposed Rates and Rate Tariff Sheet

Festival requests the Board approve the Monthly Rates and Charges to be effective May 1, 2013, as set out on the attached Tariff of Rates and Charges Sheet, as determined in the IRM Rate Generator model- Tab 13 Final Tariff Schedule. Festival also requests a Foregone Revenue Rate Rider be approved by the Board in the event the Board is unable to provide a decision and order for rates effective May 1, 2013.

Bill Impact Analysis

The table below shows the Total Bill impact of the rate adjustments for typical customers in each rate class. Large Use and G.S.> 50 kW have been shown on this table before the OCEB, as the OCEB does not apply to most customers in this class. Also attached are the bill impact worksheets produced from the 2013 IRM3 Rate Generator.

The most significant impact on rates is the addition of the Incremental Capital Rate Rider, related to large capital investment required to build a Transformer

Station. However, the total bill impact has been substantially offset as a result of reduction in RTRS rates.

Residential Hensall is the only class where there is an increase of greater than 10% on the distribution charge. This reflects the impact of Revenue to Cost Adjustments and the Incremental Capital Rate Rider. However, on a total bill basis, the increase for a typical 800 kWh customer is 2.3%, due to the impact of the decreased RTRS rates A 250 kWh Hensall customer, on a total bill basis, will experience a 4.7% increase, which is below the 10% maximum set by the Board in its Decision and Order EB-2009-0263.

Festival submits to the Board that the increases as proposed are fair and reasonable.

2013 IRM Rate Application

Bill Impact for Typical Festival Hydro Customers (at TOU Rates)

Customer Class	2012 Distribution Charge	2013 Proposed Distribution Charge	Dollar Change	% Change	2012 Total Bill	2013 Total Bill	Dollar Change	% Change
Residential, 500 kWh	23.47	24.79	1.32	**5.6%**	79.39	80.30	0.91	**1.1%**
Residential, 800 kWh	28.60	30.04	1.44	**5.0%**	117.76	118.56	0.80	**0.7%**
Residential, 1,500 kWh	40.57	42.28	1.71	**4.2%**	207.32	207.79	0.47	**0.2%**
Residential - Hensall, 500 kWh	21.37	24.10	2.73	**12.8%**	77.25	79.60	2.35	**3.0%**
Residential - Hensall, 800 kWh	25.90	29.09	3.19	**12.3%**	115.01	117.60	2.59	**2.3%**
Residential - Hensall, 1500 kWh	36.47	40.71	4.24	**11.6%**	203.15	206.20	3.05	**1.5%**
GS < 50 kW, 2,000 kWh	57.48	60.89	3.41	**5.9%**	276.86	279.06	2.20	**0.8%**
GS < 50 kW, 10,000 kWh	171.88	179.89	8.01	**4.7%**	1,265.75	1,267.61	1.86	**0.1%**
GS >50 to 4,999 kW, 100 kW, 51,100 kWh	432.07	460.16	28.09	**6.5%**	6,546.46	6,547.06	0.60	**0.0%**
GS >50 to 4,999 kW, Interval, 600 kW, 306,600 kWh	1,476.22	1,558.67	82.45	**5.6%**	38,016.04	37,922.35	(93.69)	**-0.2%**
Large Use, 5000 kW, 2,555,000 kWh	14,926.42	15,829.17	902.75	**6.0%**	292,562.53	293,582.63	1,020.10	**0.3%**
USL, 340 kWh	17.14	18.04	0.90	**5.3%**	54.77	55.47	0.70	**1.3%**
Sentinel Lights, 131 kWh, 0.36 kW	5.77	6.02	0.25	**4.3%**	20.23	20.41	0.18	**0.9%**
Street Lights, 657 kW, 239,805 kWh	3,165.19	3,209.35	44.16	**1.4%**	28,940.91	28,846.24	(94.67)	**-0.3%**

Residential - Hensall, 250 kWh **Revenue to Cost Ratio Adjustment not to cause increase in total bill to exceed 10%**

Customer Class	2011 Distribution Charge	2012 Proposed Distribution Charge	Dollar Change	% Change	2011 Total Bill	2012 Total Bill	Dollar Change	% Change
Residential - Hensall, 250 kWh (TOU)	17.60	19.95	2.35	**13.4%**	45.80	47.97	2.17	**4.7%**

In the Decision and Order for Festival's 2012 Rate Application, EB-2009-0263, with respect to the Revenue to Cost Adjustment for the Hensall Residential rates, the Board stipulated that the rate adjustments would be acceptable to the Board provided the rate impact to a Hensall Residential 250 kWh customer does not exceed 10%. As shown in the table above, the proposed total bill impact for a 250kWh customer is 4.7%. However, a large portion of this increase is a result of the Incremental Capital rate rider, which should be taken into consideration.

Conclusion: Festival submits to the Board that the adjustments to electricity rates and charges as presented in the 2013 IRM3 Rate Application EB-2012-0124 are fair and just rates. The enclosed is respectfully submitted for the Board's consideration.

Yours truly,
Festival Hydro Inc.

Original signed by W.G. Zehr

W. G. Zehr
President

Attachments:

- A - Proposed Tariff of Rates and Charges
- B - Bill Impacts
- C - 2013 IRM3 Rate Generator
- D - 2013 IRM3 Shared Tax Savings Workform
- E - 2013 IRM3 Revenue Cost Ratio Adjustment Workform
- F - 2013 IRM3 RTRS Adjustment Workform
- G - H- 2013 Incremental Capital Workform
- H – 2013 Incremental Capital Project Summary
- I - 2013 Incremental Capital Supplementary Documents

APPENDIX A

Proposed Tariff of Rates and Charges

The following is a complete Tariff Schedule based on the information entered in this model. Please review.
Note: This worksheet is **unlocked** and the print margins, row heights, number formats, etc. can be adjusted.

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 01, 2013

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

EB-2011-0167

RESIDENTIAL SERVICE CLASSIFICATION

A customer is classed as residential when all the following conditions are met:
(a) the property is zoned strictly residential by the local municipality,
(b) the account is created and maintained in the customer's name,
(c) the building is used for dwelling purposes.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.05
Distribution Volumetric Rate	$/kWh	0.0168
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kWh	0.0006
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.99

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

RESIDENTIAL - HENSALL SERVICE CLASSIFICATION

APPLICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.05
Distribution Volumetric Rate	$/kWh	0.0163
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kWh	0.0006
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0008
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.75

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose peak demand is less than 50 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Customers who are classed as General Service but consider themselves eligible to be classed as Residential must provide Festival Hydro with a copy of their tax assessment, which clearly demonstrates the zoning is for residential use only. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	29.19
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kWh	0.0001
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053

Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0044
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0010
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	1.95

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose peak demand is equal to or greater than 50 kW but less than 5,000 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	225.65
Distribution Volumetric Rate	$/kW	2.3136
Low Voltage Service Rate	$/kW	0.0689
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3508)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kW	0.0389
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0254)
Retail Transmission Rate - Network Service Rate	$/kW	2.2145
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7422
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.3520
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.9099
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.1518
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	14.81

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

LARGE USE SERVICE CLASSIFICATION

This classification refers to non-residential accounts whose monthly peak demand is equal to or greater than 5,000 kW, based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10,792.23
Distribution Volumetric Rate	$/kW	1.0015
Low Voltage Service Rate	$/kW	0.0801
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.4507)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kW	0.1910
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0250)
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.6043
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.1841
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.0667
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	718.88

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian Cross-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	12.93
Distribution Volumetric Rate	$/kWh	0.0127
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0044
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0008

Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.85

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.04
Distribution Volumetric Rate	$/kW	10.7286
Low Voltage Service Rate	$/kW	0.0504
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3881)
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.1138)
Retail Transmission Rate - Network Service Rate	$/kW	1.6785
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3751
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.4975
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.10

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. If connected to the municipal or the Province of Ontario street lighting system, decorative lighting and tree lighting services will be treated as a Street Lighting class of service. Decorative or tree lighting connected to Festival Hydro Inc.'s distribution system will be treated as a General Service Less Than 50 kW class customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.09
Distribution Volumetric Rate	$/kW	4.9728
Low Voltage Service Rate	$/kW	0.0494
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.2751)
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0984)
Retail Transmission Rate - Network Service Rate	$/kW	1.6701
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3469
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.2344
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.05

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

MICROFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Income Tax Letter	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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	%	19.66
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After 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 – During Regular Hours	$	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
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0307
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0176
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0204
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0075

APPENDIX B

Bill Impacts

Choose a Rate Class from the drop-down menu below and click UPDATE.

For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells B30 and B31.

Click the UPDATE button to refresh the sheet.

Residential

Consumption	800	**kWh**	**0**
RPP Tier One	-	**kWh**	
Load Factor			
Loss Factor	1.0307		

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	**Current Rate ($)**	**Current Charge ($)**	**Volume**	**Proposed Rate ($)**	**Proposed Charge ($)**	**Change ($)**	**Change (%)**	**% of Total RPP Bill**	**% of Total TOU Bill**
Energy First Tier (kWh)	0.00	0.0750	0.00	0.00	0.0750	0.00	0.00	0.00%	0.00%	
Energy Second Tier (kWh)	824.56	0.0880	72.56	824.56	0.0880	72.56	0.00	0.00%	58.18%	
TOU - Off Peak	527.72	0.0650	34.30	527.72	0.0650	34.30	0.00	0.00%		28.93%
TOU - Mid Peak	148.42	0.1000	14.84	148.42	0.1000	14.84	0.00	0.00%		12.52%
TOU - On Peak	148.42	0.1170	17.37	148.42	0.1170	17.37	0.00	0.00%		14.65%
Service Charge	1	14.92	14.92	1	15.05	15.05	0.13	0.87%	12.07%	12.69%
Service Charge Rate Rider(s)	1	0.00	0.00	1	0.99	0.99	0.99	0.00%	0.79%	0.84%
Distribution Volumetric Rate	800	0.0166	13.28	800	0.0168	13.44	0.16	1.20%	10.78%	11.34%
Low Voltage Volumetric Rate	800	0.0002	0.16	800	0.0002	0.16	0.00	0.00%	0.13%	0.13%
Distribution Volumetric Rate Rider(s)	800	0.0003	0.24	800	0.0005	0.40	0.16	65.33%	0.32%	0.33%
Total: Distribution			**28.60**			**30.04**	**1.44**	**5.03%**	**24.09%**	**25.34%**
Retail Transmission Rate - Network Service Rate	824.56	0.0067	5.52	824.56	0.0061	5.03	(0.49)	-8.88%	4.03%	4.24%
Retail Transmission Rate - Line and Transformation Connection Service Rate	824.56	0.005	4.12	824.56	0.0048	3.96	(0.16)	-3.88%	3.17%	3.34%
Total: Retail Transmission			9.64			8.99	(0.65)	(6.74%)	7.21%	7.58%
Sub-Total: Delivery (Distribution and Retail Transmission)			**38.24**			**39.03**	**0.79**	**2.07%**	**31.29%**	**32.92%**
Wholesale Market Service Rate	824.56	0.0052	4.29	824.56	0.0052	4.29	0.00	0.00%	3.44%	3.62%
Rural Rate Protection Charge	824.56	0.0011	0.91	824.56	0.0011	0.91	0.00	0.00%	0.73%	0.77%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.21%
Sub-Total: Regulatory			**5.44**			**5.44**	**0.00**	0.00%	**4.37%**	**4.59%**
Debt Retirement Charge (DRC)	800.00	0.00700	5.60	800.00	0.0070	**5.60**	0.00	0.00%	**4.49%**	**4.72%**
Total Bill on RPP (before taxes)			121.85			122.64	0.79	0.65%	98.33%	
HST		13%	15.84		13%	15.94	0.10	0.65%	12.78%	
Total Bill (including HST)			137.69			138.58	0.89	0.65%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(13.77)		(10%)	(13.86)	(0.09)	0.65%	-11.11%	
Total Bill on RPP (including OCEB)			**123.92**			**124.72**	**0.80**	0.65%	**100.00%**	
Total Bill on TOU (before taxes)			115.79			116.58	0.79	0.68%		98.33%
HST		13%	15.05		13%	15.16	0.10	0.68%		12.78%
Total Bill (including HST)			130.84			131.74	0.89	0.68%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(13.08)		(10%)	(13.17)	(0.09)	0.68%		-11.11%
Total Bill on TOU (including OCEB)			**117.76**			**118.56**	**0.80**	0.68%		**100.00%**

Choose a Rate Class from the drop-down menu below and click UPDATE.

For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells B30 and B31.

Click the UPDATE button to refresh the sheet.

Residential - Hensall

Consumption	800	**kWh**	**0**
RPP Tier One	-	**kWh**	
Load Factor			
Loss Factor	1.0307		

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	0.00	0.0750	0.00	0.00	0.0750	0.00	0.00	0.00%	0.00%	
Energy Second Tier (kWh)	824.56	0.0880	72.56	824.56	0.0880	72.56	0.00	0.00%	58.63%	
TOU - Off Peak	527.72	0.0650	34.30	527.72	0.0650	34.30	0.00	0.00%		29.17%
TOU - Mid Peak	148.42	0.1000	14.84	148.42	0.1000	14.84	0.00	0.00%		12.62%
TOU - On Peak	148.42	0.1170	17.37	148.42	0.1170	17.37	0.00	0.00%		14.77%
Service Charge	1	13.82	13.82	1	15.05	15.05	1.23	8.90%	12.16%	12.80%
Service Charge Rate Rider(s)	1	0.00	0.00	1	0.75	0.75	0.75	0.00%	0.61%	0.64%
Distribution Volumetric Rate	800	0.0149	11.92	800	0.0163	13.04	1.12	9.40%	10.54%	11.09%
Low Voltage Volumetric Rate	800	0.0002	0.16	800	0.0002	0.16	0.00	0.00%	0.13%	0.14%
Distribution Volumetric Rate Rider(s)	800	(0.0000)	(0.00)	800	0.0001	0.09	0.09	############	0.07%	0.07%
Total: Distribution			**25.90**			**29.09**	**3.19**	**12.32%**	**23.51%**	**24.74%**
Retail Transmission Rate - Network Service Rate	824.56	0.0067	5.52	824.56	0.0061	5.03	(0.49)	-8.88%	4.06%	4.28%
Retail Transmission Rate - Line and Transformation Connection Service Rate	824.56	0.005	4.12	824.56	0.0048	3.96	(0.16)	-3.88%	3.20%	3.37%
Total: Retail Transmission			9.64			8.99	(0.65)	(6.74%)	7.26%	7.64%
Sub-Total: Delivery (Distribution and Retail Transmission)			**35.54**			**38.08**	**2.54**	**7.15%**	**30.77%**	**32.38%**
Wholesale Market Service Rate	824.56	0.0052	4.29	824.56	0.0052	4.29	0.00	0.00%	3.46%	3.65%
Rural Rate Protection Charge	824.56	0.0011	0.91	824.56	0.0011	0.91	0.00	0.00%	0.73%	0.77%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.20%	0.21%
Sub-Total: Regulatory			**5.44**			**5.44**	**0.00**	0.00%	**4.40%**	**4.63%**
Debt Retirement Charge (DRC)	800.00	0.00700	5.60	800.00	0.0070	**5.60**	0.00	0.00%	**4.52%**	**4.76%**
Total Bill on RPP (before taxes)			119.15			121.69	2.54	2.13%	98.33%	
HST		13%	15.49		13%	15.82	0.33	2.13%	12.78%	
Total Bill (including HST)			134.64			137.51	2.87	2.13%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(13.46)		(10%)	(13.75)	(0.29)	2.13%	-11.11%	
Total Bill on RPP (including OCEB)			**121.18**			**123.76**	**2.58**	2.13%	**100.00%**	
Total Bill on TOU (before taxes)			113.09			115.63	2.54	2.25%		98.33%
HST		13%	14.70		13%	15.03	0.33	2.25%		12.78%
Total Bill (including HST)			127.79			130.66	2.87	2.25%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(12.78)		(10%)	(13.07)	(0.29)	2.25%		-11.11%
Total Bill on TOU (including OCEB)			**115.01**			**117.60**	**2.58**	2.25%		**100.00%**

Choose a Rate Class from the drop-down menu below and click UPDATE.

For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells B30 and B31.

Click the UPDATE button to refresh the sheet.

General Service Less Than 50 kW

Consumption	2,000	**kWh**	**0**
RPP Tier One	-	**kWh**	
Load Factor			
Loss Factor	1.0307		

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	0.00	0.0750	0.00	0.00	0.0750	0.00	0.00	0.00%	0.00%	
Energy Second Tier (kWh)	2,061.40	0.0880	181.40	2,061.40	0.0880	181.40	0.00	0.00%	61.61%	
TOU - Off Peak	1,319.30	0.0650	85.75	1,319.30	0.0650	85.75	0.00	0.00%		30.73%
TOU - Mid Peak	371.05	0.1000	37.11	371.05	0.1000	37.11	0.00	0.00%		13.30%
TOU - On Peak	371.05	0.1170	43.41	371.05	0.1170	43.41	0.00	0.00%		15.56%
Service Charge	1	28.88	28.88	1	29.19	29.19	0.31	1.07%	9.91%	10.46%
Service Charge Rate Rider(s)	1	0.00	0.00	1	1.95	1.95	1.95	0.00%	0.66%	0.70%
Distribution Volumetric Rate	2000	0.0146	29.20	2,000	0.0148	29.60	0.40	1.37%	10.05%	10.61%
Low Voltage Volumetric Rate	2000	0.0002	0.40	2,000	0.0002	0.40	0.00	0.00%	0.14%	0.14%
Distribution Volumetric Rate Rider(s)	2000	(0.0005)	(1.00)	2,000	(0.0001)	(0.25)	0.75	(75.00)%	-0.08%	-0.09%
Total: Distribution			**57.48**			**60.89**	**3.41**	**5.93%**	**20.68%**	**21.82%**
Retail Transmission Rate - Network Service Rate	2,061.40	0.0058	11.96	2,061.40	0.0053	10.93	(1.03)	-8.61%	3.71%	3.92%
Retail Transmission Rate - Line and Transformation Connection Service Rate	2,061.40	0.0045	9.28	2,061.40	0.0044	9.07	(0.21)	-2.26%	3.08%	3.25%
Total: Retail Transmission			21.24			20.00	(1.24)	(5.84%)	6.79%	7.17%
Sub-Total: Delivery (Distribution and Retail Transmission)			**78.72**			**80.89**	**2.17**	**2.76%**	**27.47%**	**28.99%**
Wholesale Market Service Rate	2,061.40	0.0052	10.72	2,061.40	0.0052	10.72	0.00	0.00%	3.64%	3.84%
Rural Rate Protection Charge	2,061.40	0.0011	2.27	2,061.40	0.0011	2.27	0.00	0.00%	0.77%	0.81%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.08%	0.09%
Sub-Total: Regulatory			**13.24**			**13.24**	**0.00**	0.00%	**4.50%**	**4.74%**
Debt Retirement Charge (DRC)	2,000.00	0.00700	14.00	2,000.00	0.0070	**14.00**	0.00	0.00%	**4.75%**	**5.02%**
Total Bill on RPP (before taxes)			287.36			289.53	2.17	0.76%	98.33%	
HST		13%	37.36		13%	37.64	0.28	0.76%	12.78%	
Total Bill (including HST)			324.72			327.17	2.45	0.76%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(32.47)		**(10%)**	(32.72)	(0.25)	0.76%	-11.11%	
Total Bill on RPP (including OCEB)			**292.25**			**294.45**	**2.21**	0.76%	**100.00%**	
Total Bill on TOU (before taxes)			272.23			274.40	2.17	0.80%		98.33%
HST		13%	35.39		13%	35.67	0.28	0.80%		12.78%
Total Bill (including HST)			307.62			310.07	2.45	0.80%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(30.76)		**(10%)**	(31.01)	(0.25)	0.80%		-11.11%
Total Bill on TOU (including OCEB)			**276.86**			**279.06**	**2.21**	0.80%		**100.00%**

Choose a Rate Class from the drop-down menu below and click UPDATE.
For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells B30 and B31.
Click the UPDATE button to refresh the sheet.

General Service 50 to 4,999 kW

Consumption	306,600	**kWh**	600.0	**5000**
RPP Tier One	600	**kWh**		
Load Factor	70%			
Loss Factor	1.0307			

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	**Current Rate ($)**	**Current Charge ($)**	**Volume**	**Proposed Rate ($)**	**Proposed Charge ($)**	**Change ($)**	**Change (%)**	**% of Total RPP Bill**	**% of Total TOU Bill**
Energy First Tier (kWh)	316,012.62	0.0750	23,700.95	316,012.62	0.0750	23,700.95	0.00	0.00%	73.35%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	0.00%	0.00%	
TOU - Off Peak	202,248.08	0.0650	13,146.12	202,248.08	0.0650	13,146.12	0.00	0.00%		38.52%
TOU - Mid Peak	56,882.27	0.1000	5,688.23	56,882.27	0.1000	5,688.23	0.00	0.00%		16.67%
TOU - On Peak	56,882.27	0.1170	6,655.23	56,882.27	0.1170	6,655.23	0.00	0.00%		19.50%
Service Charge	1	223.24	223.24	1	225.65	225.65	2.41	1.08%	0.70%	0.66%
Service Charge Rate Rider(s)	1	0.00	0.00	1	14.81	14.81	14.81	0.00%	0.05%	0.04%
Distribution Volumetric Rate	600	2.2889	1,373.34	600	2.3136	1,388.16	14.82	1.08%	4.30%	4.07%
Low Voltage Volumetric Rate	600	0.0689	41.34	600	0.0689	41.34	0.00	0.00%	0.13%	0.12%
Distribution Volumetric Rate Rider(s)	600	(0.2695)	(161.70)	600	(0.1855)	(111.29)	50.41	(31.17)%	-0.34%	-0.33%
Total: Distribution			**1,476.22**			**1,558.67**	**82.45**	**5.59%**	**4.82%**	**4.57%**
Retail Transmission Rate - Network Service Rate	600.00	2.4342	1,460.52	600.00	2.2145	1,328.70	(131.82)	-9.03%	4.11%	3.89%
Retail Transmission Rate - Line and Transformation Connection Service Rate	600.00	1.7981	1,078.86	600.00	1.7422	1,045.32	(33.54)	-3.11%	3.24%	3.06%
Total: Retail Transmission			2,539.38			2,374.02	(165.36)	(6.51%)	7.35%	6.96%
Sub-Total: Delivery (Distribution and Retail Transmission)			**4,015.60**			**3,932.69**	**(82.91)**	**(2.06%)**	**12.17%**	**11.52%**
Wholesale Market Service Rate	316,012.62	0.0052	1,643.27	316,012.62	0.0052	1,643.27	0.00	0.00%	5.09%	4.81%
Rural Rate Protection Charge	316,012.62	0.0011	347.61	316,012.62	0.0011	347.61	0.00	0.00%	1.08%	1.02%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%	0.00%
Sub-Total: Regulatory			**1,991.13**			**1,991.13**	**0.00**	0.00%	**6.16%**	**5.83%**
Debt Retirement Charge (DRC)	306,600.00	0.00700	2,146.20	306,600.00	0.0070	**2,146.20**	0.00	0.00%	**6.64%**	**6.29%**
Total Bill on RPP (before taxes)			31,853.88			31,770.97	(82.91)	(0.26)%	98.33%	
HST		13%	4,141.00		13%	4,130.23	(10.78)	(0.26)%	12.78%	
Total Bill (including HST)			35,994.88			35,901.20	(93.69)	(0.26)%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(3,599.49)		(10%)	(3,590.12)	9.37	(0.26)%	-11.11%	
Total Bill on RPP (including OCEB)			**32,395.40**			**32,311.08**	**(84.32)**	(0.26)%	**100.00%**	
Total Bill on TOU (before taxes)			33,642.51			33,559.60	(82.91)	(0.25)%		98.33%
HST		13%	4,373.53		13%	4,362.75	(10.78)	(0.25)%		12.78%
Total Bill (including HST)			38,016.04			37,922.35	(93.69)	(0.25)%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(3,801.60)		(10%)	(3,792.23)	9.37	(0.25)%		-11.11%
Total Bill on TOU (including OCEB)			**34,214.43**			**34,130.11**	**(84.32)**	(0.25)%		**100.00%**

Choose a Rate Class from the drop-down menu below and click UPDATE.

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Click the UPDATE button to refresh the sheet.

Large Use

Consumption	2,555,000	**kWh**	5,000.0	**5000**
RPP Tier One	600	**kWh**		
Load Factor	70%			
Loss Factor	1.0176			

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	**Current Rate ($)**	**Current Charge ($)**	**Volume**	**Proposed Rate ($)**	**Proposed Charge ($)**	**Change ($)**	**Change (%)**	**% of Total RPP Bill**	**% of Total TOU Bill**
Energy First Tier (kWh)	2,599,968.00	0.0750	194,997.60	2,599,968.00	0.0750	194,997.60	0.00	0.00%	78.23%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	0.00%	0.00%	
TOU - Off Peak	1,663,979.52	0.0650	108,158.67	1,663,979.52	0.0650	108,158.67	0.00	0.00%		40.93%
TOU - Mid Peak	467,994.24	0.1000	46,799.42	467,994.24	0.1000	46,799.42	0.00	0.00%		17.71%
TOU - On Peak	467,994.24	0.1170	54,755.33	467,994.24	0.1170	54,755.33	0.00	0.00%		20.72%
Service Charge	1	10,676.92	10,676.92	1	10,792.23	10,792.23	115.31	1.08%	4.33%	4.08%
Service Charge Rate Rider(s)	1	0.00	0.00	1	718.88	718.88	718.88	0.00%	0.29%	0.27%
Distribution Volumetric Rate	5000	0.9908	4,954.00	5,000	1.0015	5,007.50	53.50	1.08%	2.01%	1.90%
Low Voltage Volumetric Rate	5000	0.0801	400.50	5,000	0.0801	400.50	0.00	0.00%	0.16%	0.15%
Distribution Volumetric Rate Rider(s)	5000	(0.2210)	(1,105.00)	5,000	(0.2180)	(1,089.95)	15.06	(1.36)%	-0.44%	-0.41%
Total: Distribution			**14,926.42**			**15,829.17**	**902.75**	**6.05%**	**6.35%**	**5.99%**
Total: Retail Transmission										
Sub-Total: Delivery (Distribution and Retail Transmission)			**14,926.42**			**15,829.17**	**902.75**	**6.05%**	**6.35%**	**5.99%**
Wholesale Market Service Rate	2,599,968.00	0.0052	13,519.83	2,599,968.00	0.0052	13,519.83	0.00	0.00%	5.42%	5.12%
Rural Rate Protection Charge	2,599,968.00	0.0011	2,859.96	2,599,968.00	0.0011	2,859.96	0.00	0.00%	1.15%	1.08%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%	0.00%
Sub-Total: Regulatory			**16,380.05**			**16,380.05**	**0.00**	0.00%	**6.57%**	**6.20%**
Debt Retirement Charge (DRC)	2,555,000.00	0.00700	17,885.00	2,555,000.00	0.0070	**17,885.00**	0.00	0.00%	**7.18%**	**6.77%**
Total Bill on RPP (before taxes)			244,189.07			245,091.82	902.75	0.37%	98.33%	
HST		13%	31,744.58		13%	31,861.94	117.36	0.37%	12.78%	
Total Bill (including HST)			275,933.65			276,953.76	1,020.11	0.37%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(27,593.36)		(10%)	(27,695.38)	(102.01)	0.37%	-11.11%	
Total Bill on RPP (including OCEB)			**248,340.28**			**249,258.38**	**918.10**	0.37%	**100.00%**	
Total Bill on TOU (before taxes)			258,904.89			259,807.64	902.75	0.35%		98.33%
HST		13%	33,657.64		13%	33,774.99	117.36	0.35%		12.78%
Total Bill (including HST)			292,562.53			293,582.63	1,020.11	0.35%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(29,256.25)		(10%)	(29,358.26)	(102.01)	0.35%		-11.11%
Total Bill on TOU (including OCEB)			**263,306.27**			**264,224.37**	**918.10**	0.35%		**100.00%**

Choose a Rate Class from the drop-down menu below and click UPDATE.
For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells B30 and B31.
Click the UPDATE button to refresh the sheet.

Sentinel Lighting

Consumption	131	**kWh**	0.4
RPP Tier One	600	**kWh**	
Load Factor	50%		
Loss Factor	1.0307		

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	135.43	0.0750	10.16	135.43	0.0750	10.16	0.00	0.00%	51.75%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	0.00%	0.00%	
TOU - Off Peak	86.68	0.0650	5.63	86.68	0.0650	5.63	0.00	0.00%		27.60%
TOU - Mid Peak	24.38	0.1000	2.44	24.38	0.1000	2.44	0.00	0.00%		11.94%
TOU - On Peak	24.38	0.1170	2.85	24.38	0.1170	2.85	0.00	0.00%		13.97%
Service Charge	1	2.02	2.02	1	2.04	2.04	0.02	0.99%	10.39%	9.99%
Service Charge Rate Rider(s)	1	0.00	0.00	1	0.10	0.10	0.10	0.00%	0.51%	0.49%
Distribution Volumetric Rate	0	10.6140	3.82	0	10.7286	3.86	0.04	1.08%	19.68%	18.92%
Low Voltage Volumetric Rate	0	0.0504	0.02	0	0.0504	0.02	0.00	0.00%	0.09%	0.09%
Distribution Volumetric Rate Rider(s)	0	(0.2520)	(0.09)	0	(0.0044)	(0.00)	0.09	(98.25)%	-0.01%	-0.01%
Total: Distribution			**5.77**			**6.02**	**0.25**	**4.33%**	**30.67%**	**29.49%**
Retail Transmission Rate - Network Service Rate	0.36	1.8451	0.66	0.36	1.6785	0.60	(0.06)	-9.09%	3.06%	2.94%
Retail Transmission Rate - Line and Transformation Connection Service Rate	0.36	1.4192	0.51	0.36	1.3751	0.50	(0.01)	-1.96%	2.55%	2.45%
Total: Retail Transmission			1.17			1.10	(0.07)	(5.98%)	5.60%	5.39%
Sub-Total: Delivery (Distribution and Retail Transmission)			**6.94**			**7.12**	**0.18**	**2.59%**	**36.27%**	**34.88%**
Wholesale Market Service Rate	135.43	0.0052	0.70	135.43	0.0052	0.70	0.00	0.00%	3.59%	3.45%
Rural Rate Protection Charge	135.43	0.0011	0.15	135.43	0.0011	0.15	0.00	0.00%	0.76%	0.73%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	1.27%	1.22%
Sub-Total: Regulatory			**1.10**			**1.10**	**0.00**	0.00%	**5.62%**	**5.41%**
Debt Retirement Charge (DRC)	131.40	0.00700	0.92	131.40	0.0070	**0.92**	0.00	0.00%	**4.69%**	**4.51%**
Total Bill on RPP (before taxes)			19.12			19.30	0.18	0.94%	98.33%	
HST		13%	2.49		13%	2.51	0.02	0.94%	12.78%	
Total Bill (including HST)			21.61			21.81	0.20	0.94%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(2.16)		(10%)	(2.18)	(0.02)	0.94%	-11.11%	
Total Bill on RPP (including OCEB)			**19.45**			**19.63**	**0.18**	0.94%	**100.00%**	
Total Bill on TOU (before taxes)			19.89			20.07	0.18	0.90%		98.33%
HST		13%	2.59		13%	2.61	0.02	0.90%		12.78%
Total Bill (including HST)			22.48			22.68	0.20	0.90%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(2.25)		(10%)	(2.27)	(0.02)	0.90%		-11.11%
Total Bill on TOU (including OCEB)			**20.23**			**20.41**	**0.18**	0.90%		**100.00%**

Choose a Rate Class from the drop-down menu below and click UPDATE.
For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells B30 and B31.
Click the UPDATE button to refresh the sheet.

Street Lighting

Consumption	239,805	**kWh**	657.0	**657**
RPP Tier One	600	**kWh**		
Load Factor	50%			
Loss Factor	1.0307			

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	**Current Rate ($)**	**Current Charge ($)**	**Volume**	**Proposed Rate ($)**	**Proposed Charge ($)**	**Change ($)**	**Change (%)**	**% of Total RPP Bill**	**% of Total TOU Bill**
Energy First Tier (kWh)	247,167.01	0.0750	18,537.53	247,167.01	0.0750	18,537.53	0.00	0.00%	67.60%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	0.00%	0.00%	
TOU - Off Peak	158,186.89	0.0650	10,282.15	158,186.89	0.0650	10,282.15	0.00	0.00%		35.64%
TOU - Mid Peak	44,490.06	0.1000	4,449.01	44,490.06	0.1000	4,449.01	0.00	0.00%		15.42%
TOU - On Peak	44,490.06	0.1170	5,205.34	44,490.06	0.1170	5,205.34	0.00	0.00%		18.05%
Service Charge	1	1.08	1.08	1	1.09	1.09	0.01	0.93%	0.00%	0.00%
Service Charge Rate Rider(s)	1	0.00	0.00	1	0.05	0.05	0.05	0.00%	0.00%	0.00%
Distribution Volumetric Rate	657	4.9197	3,232.24	657	4.9728	3,267.13	34.89	1.08%	11.91%	11.33%
Low Voltage Volumetric Rate	657	0.0494	32.46	657	0.0494	32.46	0.00	0.00%	0.12%	0.11%
Distribution Volumetric Rate Rider(s)	657	(0.1531)	(100.59)	657	(0.1391)	(91.38)	9.21	(9.16)%	-0.33%	-0.32%
Total: Distribution			**3,165.19**			**3,209.35**	**44.16**	**1.40%**	**11.70%**	**11.13%**
Retail Transmission Rate - Network Service Rate	657.00	1.8358	1,206.12	657.00	1.6701	1,097.26	(108.86)	-9.03%	4.00%	3.80%
Retail Transmission Rate - Line and Transformation Connection Service Rate	657.00	1.3901	913.30	657.00	1.3469	884.91	(28.39)	-3.11%	3.23%	3.07%
Total: Retail Transmission			2,119.42			1,982.17	(137.25)	(6.48%)	7.23%	6.87%
Sub-Total: Delivery (Distribution and Retail Transmission)			**5,284.61**			**5,191.52**	**(93.09)**	**(1.76%)**	**18.93%**	**18.00%**
Wholesale Market Service Rate	247,167.01	0.0052	1,285.27	247,167.01	0.0052	1,285.27	0.00	0.00%	4.69%	4.46%
Rural Rate Protection Charge	247,167.01	0.0011	271.88	247,167.01	0.0011	271.88	0.00	0.00%	0.99%	0.94%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.00%	0.00%
Sub-Total: Regulatory			**1,557.40**			**1,557.40**	**0.00**	0.00%	**5.68%**	**5.40%**
Debt Retirement Charge (DRC)	239,805.00	0.00700	1,678.64	239,805.00	0.0070	**1,678.64**	0.00	0.00%	**6.12%**	**5.82%**
Total Bill on RPP (before taxes)			27,058.17			26,965.08	(93.09)	(0.34)%	98.33%	
HST		13%	3,517.56		13%	3,505.46	(12.10)	(0.34)%	12.78%	
Total Bill (including HST)			30,575.73			30,470.54	(105.19)	(0.34)%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(3,057.57)		(10%)	(3,047.05)	10.52	(0.34)%	-11.11%	
Total Bill on RPP (including OCEB)			**27,518.16**			**27,423.49**	**(94.67)**	(0.34)%	**100.00%**	
Total Bill on TOU (before taxes)			28,457.14			28,364.05	(93.09)	(0.33)%		98.33%
HST		13%	3,699.43		13%	3,687.33	(12.10)	(0.33)%		12.78%
Total Bill (including HST)			32,156.57			32,051.38	(105.19)	(0.33)%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(3,215.66)		(10%)	(3,205.14)	10.52	(0.33)%		-11.11%
Total Bill on TOU (including OCEB)			**28,940.91**			**28,846.24**	**(94.67)**	(0.33)%		**100.00%**

Choose a Rate Class from the drop-down menu below and click UPDATE.

For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells B30 and B31.

Click the UPDATE button to refresh the sheet.

Unmetered Scattered Load

Consumption	340	**kWh**	**0**
RPP Tier One	600	**kWh**	
Load Factor			
Loss Factor	1.0307		

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	**Current Rate ($)**	**Current Charge ($)**	**Volume**	**Proposed Rate ($)**	**Proposed Charge ($)**	**Change ($)**	**Change (%)**	**% of Total RPP Bill**	**% of Total TOU Bill**
Energy First Tier (kWh)	350.44	0.0750	26.28	350.44	0.0750	26.28	0.00	0.00%	49.17%	
Energy Second Tier (kWh)	0.00	0.0880	0.00	0.00	0.0880	0.00	0.00	0.00%	0.00%	
TOU - Off Peak	224.28	0.0650	14.58	224.28	0.0650	14.58	0.00	0.00%		26.28%
TOU - Mid Peak	63.08	0.1000	6.31	63.08	0.1000	6.31	0.00	0.00%		11.37%
TOU - On Peak	63.08	0.1170	7.38	63.08	0.1170	7.38	0.00	0.00%		13.31%
Service Charge	1	12.79	12.79	1	12.93	12.93	0.14	1.09%	24.19%	23.31%
Service Charge Rate Rider(s)	1	0.00	0.00	1	0.85	0.85	0.85	0.00%	1.59%	1.53%
Distribution Volumetric Rate	340	0.0126	4.28	340	0.0127	4.32	0.03	0.79%	8.08%	7.78%
Low Voltage Volumetric Rate	340	0.0002	0.07	340	0.0002	0.07	0.00	0.00%	0.13%	0.12%
Distribution Volumetric Rate Rider(s)	340	0.0000	0.00	340	(0.0004)	(0.12)	(0.12)	0.00%	-0.23%	-0.22%
Total: Distribution			**17.14**			**18.04**	**0.90**	**5.25%**	**33.75%**	**32.52%**
Retail Transmission Rate - Network Service Rate	350.44	0.0058	2.03	350.44	0.0053	1.86	(0.17)	-8.37%	3.48%	3.35%
Retail Transmission Rate - Line and Transformation Connection Service Rate	350.44	0.0045	1.58	350.44	0.0044	1.54	(0.04)	-2.53%	2.88%	2.78%
Total: Retail Transmission			3.61			3.40	(0.21)	(5.82%)	6.36%	6.13%
Sub-Total: Delivery (Distribution and Retail Transmission)			**20.75**			**21.44**	**0.69**	**3.33%**	**40.11%**	**38.65%**
Wholesale Market Service Rate	350.44	0.0052	1.82	350.44	0.0052	1.82	0.00	0.00%	3.41%	3.29%
Rural Rate Protection Charge	350.44	0.0011	0.39	350.44	0.0011	0.39	0.00	0.00%	0.72%	0.69%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.47%	0.45%
Sub-Total: Regulatory			**2.46**			**2.46**	**0.00**	0.00%	**4.60%**	**4.43%**
Debt Retirement Charge (DRC)	340.00	0.00700	2.38	340.00	0.0070	**2.38**	0.00	0.00%	**4.45%**	**4.29%**
Total Bill on RPP (before taxes)			51.87			52.56	0.69	1.33%	98.33%	
HST		13%	6.74		13%	6.83	0.09	1.33%	12.78%	
Total Bill (including HST)			58.61			59.39	0.78	1.33%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(5.86)		(10%)	(5.94)	(0.08)	1.33%	-11.11%	
Total Bill on RPP (including OCEB)			**52.75**			**53.45**	**0.70**	1.33%	**100.00%**	
Total Bill on TOU (before taxes)			53.85			54.54	0.69	1.28%		98.33%
HST		13%	7.00		13%	7.09	0.09	1.28%		12.78%
Total Bill (including HST)			60.85			61.63	0.78	1.28%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(6.09)		(10%)	(6.16)	(0.08)	1.28%		-11.11%
Total Bill on TOU (including OCEB)			**54.77**			**55.47**	**0.70**	1.28%		**100.00%**

APPENDIX C

2013 IRM3 Rate Generator

3RD Generation Incentive Regulation Model for 2013 Filers

Version 2.3

Utility Name	Festival Hydro Inc.
Service Territory	(if applicable)
Assigned EB Number	EB-2011-0167
Name of Contact and Title	Debbie Reece, CFO
Phone Number	519-271-4703 x.268
Email Address	dreece@festivalhydro.com
We are applying for rates effective	May-01-13

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

3RD Generation Incentive Regulation Model for 2013 Filers

Festival Hydro Inc.

3RD Generation Incentive Regulation Model for 2013 Filers

Festival Hydro Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, including the MicroFit Class.

How many classes are listed on your most recent Board-Approved Tariff of Rates and Charges? 9

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	Residential
2	Residential - Hensall
3	General Service Less Than 50 kW
4	General Service 50 to 4,999 kW
5	Large Use
6	Unmetered Scattered Load
7	Sentinel Lighting
8	Street Lighting
9	MicroFit

For each class, Applicants are required to copy and paste the class descriptions (located directly under the class name) and the description of the applicability of those rates (description is found under the class name and directly under the word "APPLICATION"). By using the drop-down lists located under the column labeled "Rate Description", please select the descriptions of the rates and charges that **BEST MATCHES** the descriptions on your most recent Board-Approved Tariff of Rates and Charges. If the description is not found in the drop-down list, please enter the description in the green cells under the correct class exactly as it appears on the tariff. Please do not enter more than one "Service Charge" for each class for which a base monthly fixed charge applies. **Note: If the current RRRP consists of only one line on the current tariff schedule, enter the same rate for "Rural Rate Protection Charge - effective until April 30, 2012" and "Rural Rate Protection Charge - effective on and after May 1, 2012".

Festival Hydro Inc.

TARIFF OF RATES AND CHARGES

Residential Service Classification

A customer is classed as residential when all the following conditions are met:
(a) the property is zoned strictly residential by the local municipality,
(b) the account is created and maintained in the customer's name,
(c) the building is used for dwelling purposes.
Exceptions may be made for properties zoned for farming use, under the following conditions:
(a) the principal use of the service is for the residence,

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component (If applicable, Effective Date MUST be included in rate description)

Service Charge	$	14.92
Distribution Volumetric Rate	$/kWh	0.0166
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kWh	0.0011

Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kWh	0.0006
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0005)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012		
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.2500

Residential - Hensall Service Classification

APPLICATION

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	13.82
Distribution Volumetric Rate	$/kWh	0.0149
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kWh	0.0007
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kWh	0.0006
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW Service Classification

This classification refers to a non residential account whose peak demand is less than 50 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Customers who are classed as General Service but consider themselves eligible to be classed as Residential must provide Festival Hydro with a copy of their tax assessment, which clearly demonstrates the zoning is for residential use only. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	28.88
Distribution Volumetric Rate	$/kWh	0.0146
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kWh	0.0007
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kWh	0.0001
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0058
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW Service Classification

This classification refers to a non residential account whose peak demand is equal to or greater than 50 kW but less than 5,000 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component (If applicable, Effective Date MUST be included in rate description)

Service Charge	$	223.24
Distribution Volumetric Rate	$/kW	2.2889
Low Voltage Service Rate	$/kW	0.0689
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3508)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kW	0.0782
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kW	0.0389
Rate Rider for Tax Change – Effective until April 30, 2013	$/kW	(0.0358)
Retail Transmission Rate - Network Service Rate	$/kW	2.4342
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7981
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.5854
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.9712

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Large Use Service Classification

This classification refers to non-residential accounts whose monthly peak demand is equal to or greater than 5,000 kW, based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	10,676.92
Distribution Volumetric Rate	$/kW	0.9908
Low Voltage Service Rate	$/kW	0.0801
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.4507)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kW	0.0737
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kW	0.1910
Rate Rider for Tax Change – Effective until April 30, 2013	$/kW	(0.0350)
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.8627
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.2542

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load Service Classification

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian Cross-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component (**If applicable, Effective Date MUST be included in rate description**)

Service Charge (per connection)	$	12.79
Distribution Volumetric Rate	$/kWh	0.0126
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kWh	0.0014
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0006)

Retail Transmission Rate - Network Service Rate	$/kWh	0.0058
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Sentinel Lighting Service Classification

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge (per connection)	$	2.02
Distribution Volumetric Rate	$/kW	10.6140
Low Voltage Service Rate	$/kW	0.0504
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3881)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kW	0.2723
Rate Rider for Tax Change – Effective until April 30, 2013	$/kW	(0.1362)
Retail Transmission Rate - Network Service Rate	$/kW	1.8451
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4192

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.2500

Street Lighting Service Classification

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. If connected to the municipal or the Province of Ontario street lighting system, decorative lighting and tree lighting services will be treated as a Street Lighting class of service. Decorative or tree lighting connected to Festival Hydro Inc.'s distribution system will be treated as a General Service Less Than 50 kW class customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge (per connection)	$	1.08
Distribution Volumetric Rate	$/kW	4.9197
Low Voltage Service Rate	$/kW	0.0494
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.2751)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kW	0.2411
Rate Rider for Tax Change – Effective until April 30, 2013	$/kW	(0.1191)
Retail Transmission Rate - Network Service Rate	$/kW	1.8358
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3901

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

MicroFit Service Classification

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component **(If applicable, Effective Date MUST be included in rate description)**

Service Charge	$	5.25

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

2005

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [2]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [2]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					0					0
RSVA - Wholesale Market Service Charge	1580					0					0
RSVA - Retail Transmission Network Charge	1584					0					0
RSVA - Retail Transmission Connection Charge	1586					0					0
RSVA - Power (excluding Global Adjustment)	1588					0					0
RSVA - Power - Sub-account - Global Adjustment	1588					0					0
Recovery of Regulatory Asset Balances	1590		(210,414)			(210,414)		(318,926)			(318,926)
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595					0					0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595					0					0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	(210,414)	0	0	(210,414)	0	(318,926)	0	0	(318,926)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	(210,414)	0	0	(210,414)	0	(318,926)	0	0	(318,926)
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	286,454	(160,425)			126,029	119,618	6,699			126,316
Total of Group 1 and Account 1562		286,454	(370,839)	0	0	(84,385)	119,618	(312,227)	0	0	(192,610)
Special Purpose Charge Assessment Variance Account[4]	**1521**										
LRAM Variance Account	**1568**										
Total including Accounts 1562, 1521 and 1568		286,454	(370,839)	0	0	(84,385)	119,618	(312,227)	0	0	(192,610)

2006

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [2]	Board-Approved Disposition during 2006	Adjustments during 2006 - other [2]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [1]
Group 1 Accounts									
LV Variance Account	1550	0				0	0		
RSVA - Wholesale Market Service Charge	1580	0				0	0		
RSVA - Retail Transmission Network Charge	1584	0				0	0		
RSVA - Retail Transmission Connection Charge	1586	0				0	0		
RSVA - Power (excluding Global Adjustment)	1588	0				0	0		
RSVA - Power - Sub-account - Global Adjustment	1588	0				0	0		
Recovery of Regulatory Asset Balances	1590	(210,414)	24,345	(135,569)		(50,500)	(318,926)	(16,356)	(279,486)
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0				0	0		
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0				0	0		
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0				0	0		
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		(210,414)	24,345	(135,569)	0	(50,500)	(318,926)	(16,356)	(279,486)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(210,414)	24,345	(135,569)	0	(50,500)	(318,926)	(16,356)	(279,486)
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562	126,029				126,029	126,316	3,762	
Total of Group 1 and Account 1562		(84,385)	24,345	(135,569)	0	75,529	(192,610)	(12,594)	(279,486)
Special Purpose Charge Assessment Variance Account[4]	**1521**								
LRAM Variance Account	**1568**								
Total including Accounts 1562, 1521 and 1568		(84,385)	24,345	(135,569)	0	75,529	(192,610)	(12,594)	(279,486)

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

1 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

2 For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

3 If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

4 Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

5 Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	Adjustments during 2006 - other [2]	Closing Interest Amounts as of Dec-31-06	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [2]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [1]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [1]	Closing Interest Amounts as of Dec-31-07	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [2]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [1]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08
Group 1 Accounts																			
LV Variance Account	1550		0	0				0	0				0	0				0	0
RSVA - Wholesale Market Service Charge	1580		0	0				0	0				0	0				0	0
RSVA - Retail Transmission Network Charge	1584		0	0				0	0				0	0				0	0
RSVA - Retail Transmission Connection Charge	1586		0	0				0	0				0	0				0	0
RSVA - Power (excluding Global Adjustment)	1588		0	0				0	0				0	0				0	0
RSVA - Power - Sub-account - Global Adjustment	1588		0	0				0	0				0	0				0	0
Recovery of Regulatory Asset Balances	1590		(55,796)	(50,500)	108,564			58,064	(55,796)	(104)			(55,900)	58,064	36,759			94,823	(55,900)
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595		0	0				0	0				0	0				0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595		0	0				0	0				0	0				0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595		0	0				0	0				0	0				0	0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	(55,796)	(50,500)	108,564	0	0	58,064	(55,796)	(104)	0	0	(55,900)	58,064	36,759	0	0	94,823	(55,900)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	(55,796)	(50,500)	108,564	0	0	58,064	(55,796)	(104)	0	0	(55,900)	58,064	36,759	0	0	94,823	(55,900)
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deferred Payments in Lieu of Taxes	1562		130,078	126,029				126,029	130,078	5,959			136,037	126,029				126,029	136,037
Total of Group 1 and Account 1562		0	74,282	75,529	108,564	0	0	184,093	74,282	5,855	0	0	80,137	184,093	36,759	0	0	220,852	80,137
Special Purpose Charge Assessment Variance Account[4]	**1521**																		
LRAM Variance Account	**1568**																		
Total including Accounts 1562, 1521 and 1568		0	74,282	75,529	108,564	0	0	184,093	74,282	5,855	0	0	80,137	184,093	36,759	0	0	220,852	80,137

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

Account Descriptions	Account Number	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [1]	Closing Interest Amounts as of Dec-31-08	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [2]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [1]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [1]	Closing Interest Amounts as of Dec-31-09	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [2]	Board-Approved Disposition during 2010	Adjustments during 2010 - other [1]
Group 1 Accounts																			
LV Variance Account	1550				0	0	(42,809)			(42,809)	0	(178)			(178)	(42,809)	(14,640)		
RSVA - Wholesale Market Service Charge	1580				0	0	(114,669)			(114,669)	0	(1,182)			(1,182)	(114,669)	(586,655)		
RSVA - Retail Transmission Network Charge	1584				0	0	(321,110)			(321,110)	0	(1,841)			(1,841)	(321,110)	28,679		
RSVA - Retail Transmission Connection Charge	1586				0	0	67,338			67,338	0	(1,564)			(1,564)	67,338	125,612		
RSVA - Power (excluding Global Adjustment)	1588				0	0	93,856			93,856	0	91			91	93,856	46,846		
RSVA - Power - Sub-account - Global Adjustment	1588				0	0	812,186			812,186	0	874			874	812,186	(95,446)		
Recovery of Regulatory Asset Balances	1590	3,326			(52,574)	94,823				94,823	(52,574)	1,079			(51,495)	94,823			
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595				0	0				0	0				0	0			
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595				0	0				0	0				0	0			
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595				0	0				0	0				0	0	0	0	
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		3,326	0	0	(52,574)	94,823	494,792	0	0	589,615	(52,574)	(2,721)	0	0	(55,295)	589,615	(495,604)	0	0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		3,326	0	0	(52,574)	94,823	(317,394)	0	0	(222,571)	(52,574)	(3,595)	0	0	(56,169)	(222,571)	(400,158)	0	0
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	0	0	0	812,186	0	0	812,186	0	874	0	0	874	812,186	(95,446)	0	0
Deferred Payments in Lieu of Taxes	1562	5,017			141,054	126,029				126,029	141,054	1,434			142,488	126,029	0	0	
Total of Group 1 and Account 1562		8,343	0	0	88,480	220,852	494,792	0	0	715,644	88,480	(1,287)	0	0	87,193	715,644	(495,604)	0	0
Special Purpose Charge Assessment Variance Account[4]	**1521**																(114,812)	(227,819)	0
LRAM Variance Account	**1568**																		
Total including Accounts 1562, 1521 and 1568		8,343	0	0	88,480	220,852	494,792	0	0	715,644	88,480	(1,287)	0	0	87,193	715,644	(610,416)	(227,819)	0

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

2010

Account Descriptions	Account Number	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [2]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts							
LV Variance Account	1550	(57,449)	(178)	(943)		439	(682)
RSVA - Wholesale Market Service Charge	1580	(701,324)	(1,182)	(3,415)		1,759	(2,838)
RSVA - Retail Transmission Network Charge	1584	(292,431)	(1,841)	(2,750)		3,497	(1,094)
RSVA - Retail Transmission Connection Charge	1586	192,950	(1,564)	1,068		4,441	3,945
RSVA - Power (excluding Global Adjustment)	1588	140,702	91	141			232
RSVA - Power - Sub-account - Global Adjustment	1588	716,740	874	3,190			4,064
Recovery of Regulatory Asset Balances	1590	94,823	(51,495)	756			(50,739)
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595	0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595	0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595	0	0	0	0		0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		94,011	(55,295)	(1,953)	0	10,136	(47,112)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		(622,729)	(56,169)	(5,143)	0	10,136	(51,176)
RSVA - Power - Sub-account - Global Adjustment	**1588**	716,740	874	3,190	0	0	4,064
Deferred Payments in Lieu of Taxes	1562	126,029	142,488	1,005			143,493
Total of Group 1 and Account 1562		220,040	87,193	(948)	0	10,136	96,381
Special Purpose Charge Assessment Variance Account[4]	**1521**	113,007	0	1,009			1,009
LRAM Variance Account	**1568**	0					0
Total including Accounts 1562, 1521 and 1568		333,047	87,193	61	0	10,136	97,390

2011

Account Descriptions	Opening Principal Amounts as of Jan-1-11	Transactions Debit / (Credit) during 2011 excluding interest and adjustments [2]	Board-Approved Disposition during 2011	Other [1] Adjustments during Q1 2011	Other [1] Adjustments during Q2 2011	Other [1] Adjustments during Q3 2011	Other [1] Adjustments during Q4 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Adjustments during 2011 - other [1]	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts													
LV Variance Account	(57,449)	43,855						(13,594)	(682)	(776)			(1,458)
RSVA - Wholesale Market Service Charge	(701,324)	(592,130)						(1,293,454)	(2,838)	(9,379)			(12,217)
RSVA - Retail Transmission Network Charge	(292,431)	233,041						(59,390)	(1,094)	(320)			(1,414)
RSVA - Retail Transmission Connection Charge	192,950	133,660						326,610	3,945	2,327			6,272
RSVA - Power (excluding Global Adjustment)	140,702	(117,907)						22,795	232	2,262			2,494
RSVA - Power - Sub-account - Global Adjustment	716,740	537,995						1,254,735	4,064	9,587			13,651
Recovery of Regulatory Asset Balances	94,823	0						94,823	(50,739)	1,394			(49,345)
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	0							0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	0							0	0				0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	0	0						0	0				0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)	94,011	238,514	0	0	0	0	0	332,525	(47,112)	5,095	0	0	(42,017)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)	(622,729)	(299,481)	0	0	0	0	0	(922,210)	(51,176)	(4,492)	0	0	(55,668)
RSVA - Power - Sub-account - Global Adjustment	716,740	537,995	0	0	0	0	0	1,254,735	4,064	9,587	0	0	13,651
Deferred Payments in Lieu of Taxes	126,029							126,029	143,493	1,853		617	145,963
Total of Group 1 and Account 1562	220,040	238,514	0	0	0	0	0	458,554	96,381	6,948	0	617	103,946
Special Purpose Charge Assessment Variance Account[4]	113,007	(107,327)						5,680	1,009	521			1,530
LRAM Variance Account	0						0	0	0				0
Total including Accounts 1562, 1521 and 1568	333,047	131,188	0	0	0	0	0	464,235	97,390	7,469	0	617	105,476

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

Applicants that did not have the balance in Account 1521 cleared by the Board in the 2012 rate proceedings are expected to file to dispose of Account 1521 in the 2013 rate proceedings. No Account 1521 balance is to be filed for clearance in the 2013 rate proceedings for those distributors that had account 1521 cleared by the Board in the 2012 rate proceedings.

In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

Please complete the following continuity schedule for the following Deferral / Variance Accounts. Enter information into green cells only.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2013 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2012 EDR process (CoS or IRM) you received approval for the December 31, 2010 balances, the starting point for your entries below should be the adjustment column BF for principal and column BK for interest. This will allow for the correct starting point for the 2011 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Please refer to the footnotes for further instructions.

		2012				Projected Interest on Dec-31-11 Balances			2.1.7 RRR	
Account Descriptions	**Account Number**	**Principal Disposition during 2012 - instructed by Board**	**Interest Disposition during 2012 - instructed by Board**	**Closing Principal Balances as of Dec 31-11 Adjusted for Dispositions during 2012**	**Closing Interest Balances as of Dec 31-11 Adjusted for Dispositions during 2012**	**Projected Interest from Jan 1, 2012 to December 31, 2012 on Dec 31 -11 balance adjusted for disposition during 2012 [3]**	**Projected Interest from January 1, 2013 to April 30, 2013 on Dec 31 -11 balance adjusted for disposition during 2012 [3]**	**Total Claim**	**As of Dec 31-11**	**Variance RRR vs. 2011 Balance *(Principal + Interest)***
Group 1 Accounts										
LV Variance Account	1550			(13,594)	(1,458)	(200)	(67)	(15,319)	(15,052)	0
RSVA - Wholesale Market Service Charge	1580			(1,293,454)	(12,217)	(19,014)	(6,338)	(1,331,023)	(1,305,671)	(0)
RSVA - Retail Transmission Network Charge	1584			(59,390)	(1,414)	(873)	(291)	(61,968)	(60,803)	0
RSVA - Retail Transmission Connection Charge	1586			326,610	6,272	4,801	1,600	339,283	332,881	(0)
RSVA - Power (excluding Global Adjustment)	1588			22,795	2,494	335	112	25,736	25,289	(0)
RSVA - Power - Sub-account - Global Adjustment	1588			1,254,735	13,651	18,445	6,148	1,292,979	1,268,386	(0)
Recovery of Regulatory Asset Balances	1590			94,823	(49,345)	1,394	465	47,336	45,478	0
Disposition and Recovery/Refund of Regulatory Balances (2008)[5]	1595			0	0	0		0		0
Disposition and Recovery/Refund of Regulatory Balances (2009)[5]	1595			0	0	0		0		0
Disposition and Recovery/Refund of Regulatory Balances (2010)[5]	1595			0	0	0		0		0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		0	0	332,525	(42,017)	4,888	1,629	297,026	290,507	(1)
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		0	0	(922,210)	(55,668)	(13,556)	(4,519)	(995,953)	(977,878)	(1)
RSVA - Power - Sub-account - Global Adjustment	**1588**	0	0	1,254,735	13,651	18,445	6,148	1,292,979	1,268,386	(0)
Deferred Payments in Lieu of Taxes	1562	126,029	145,963	(0)	0	0	0	0	19,350	(252,642)
										0
Total of Group 1 and Account 1562		126,029	145,963	332,525	(42,017)	4,888	1,629	297,026	309,857	(252,643)
Special Purpose Charge Assessment Variance Account[4]	**1521**	5,689	1,527	(9)	3	(0)	0	(6)	7,210	(0)
LRAM Variance Account	**1568**			0	0	0	0	0		0
Total including Accounts 1562, 1521 and 1568		131,718	147,490	332,517	(42,014)	4,888	1,629	297,020	317,067	(252,644)

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

If the LDC's 2013 rate year begins January 1, 2013, the projected interest is recorded from January 1, 2012 to December 31, 2012 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision. If the LDC's 2013 rate year begins May 1, 2013 the projected interest is recorded from January 1, 2012 to April 30, 2013 on the December 31, 2011 balance adjusted for the disposed balances approved by the Board in the 2012 rate decision.

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In accordance with section 8 of the Special Purpose Charge ("SPC") Regulation, Ontario Regulation 66/10, distributors were required to apply to the Board no later than April 15, 2012 for an order authorizing the distributor to clear the balance in Account 1521. As per the Board's April 23, 2010 letter, the Board stated that it expected that requests for disposition of the balance in Account 1521 were to be addressed as part of the proceedings to set rates for the 2012 rate year, except in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

Include Account 1595 as part of Group 1 accounts (lines 31, 32 and 33) for review and disposition if the recovery (or refund) period has been completed. If the recovery (or refund) period has not been completed, do not include the respective balance in Account 1595 for disposition at this time.

In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and the most recent 12-month actual volumetric data, use the most recent 12-month actual data. Do not enter data for the MicroFit class.

Rate Class	Unit	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion*	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]	1568 LRAM Variance Account Class Allocation ($ amounts)
Residential	$/kWh	141,132,375		27,584,014	0	5,332,660					
Residential - Hensall	$/kWh	4,143,109		808,731	0	105,503					
General Service Less Than 50 kW	$/kWh	67,469,308		14,512,693	0	1,662,577					
General Service 50 to 4,999 kW	$/kW	316,941,804	797,792	301,254,388	758,304	2,070,342					
Large Use	$/kW	65,544,852	128,687	65,544,852	128,687	307,077					
Unmetered Scattered Load	$/kWh	629,732			0	31,456					
Sentinel Lighting	$/kW	234,690	679		0	6,433					
Street Lighting		3,904,130	11,255	2,801,582	8,077	94,229					
MicroFit											
	Total	**600,000,000**	**938,413**	**412,506,260**	**895,068**	**9,610,277**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0**
										Balance as per Sheet 5	0
										Variance	0

Threshold Test

Total Claim (including Account 1521, 1562 and 1568)	$297,020	
Total Claim for Threshold Test (All Group 1 Accounts)	$297,026	
Threshold Test (Total claim per kWh) [3]	0.0005	**Claim does not meet the threshold test. If data has been entered on Sheet 5 for Accounts 1521 and 1562, the model will only dispose of Accounts 1521 and 1562.**

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balances

[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[3] The Threshold Test does not include the amount in 1521, 1562 nor 1568.

No input required. This worksheet allocates the deferral/variance account balances (Group 1, 1521, 1588 GA, 1562 and 1568) to the appropriate classes as per the EDDVAR Report dated July 31, 2009

Allocation of Group 1 Accounts (including Accounts 1521, 1562, 1568)

Rate Class	% of Total kWh	% of Total non-RPP kWh	% of Total Distribution Revenue	1550	1580	1584	1586	1588*	1588 GA	1590	1595 (2008)	1595 (2009)	1595 (2010)	1521	1562	1568
Residential	23.5%	6.7%	55.5%	0	0	0	0	0	0	0	0	0	0	(1)	0	0
Residential - Hensall	0.7%	0.2%	1.1%	0	0	0	0	0	0	0	0	0	0	(0)	0	0
General Service Less Than 50 kW	11.2%	3.5%	17.3%	0	0	0	0	0	0	0	0	0	0	(1)	0	0
General Service 50 to 4,999 kW	52.8%	73.0%	21.5%	0	0	0	0	0	0	0	0	0	0	(3)	0	0
Large Use	10.9%	15.9%	3.2%	0	0	0	0	0	0	0	0	0	0	(1)	0	0
Unmetered Scattered Load	0.1%	0.0%	0.3%	0	0	0	0	0	0	0	0	0	0	(0)	0	0
Sentinel Lighting	0.0%	0.0%	0.1%	0	0	0	0	0	0	0	0	0	0	(0)	0	0
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MicroFit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**99.3%**	**99.3%**	**99.0%**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(6)**	**0**	**0**

** RSVA - Power (Excluding Global Adjustment)*

Input required at cell C15 only. This workshseet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and associated rate riders for the global adjustment sub-account. Rate Riders will not be generated for the MicroFit class.

Please indicate the Rate Rider Recovery Period (in years) | **1**

Rate Class	**Unit**	**Billed kWh**	**Billed kW**	**Balance of Accounts Allocated by kWh/kW (RPP) or Distribution**	**Deferral/Variance Account Rate Rider**	**Allocation of Balance in Account 1588 Global**	**Billed kWh or Estimated kW for Non-RPP**	**Global Adjustment Rate Rider**
Residential	$/kWh	141,132,375		(1)	0.0000	0	27,584,014	0.0000
Residential - Hensall	$/kWh	4,143,109		(0)	0.0000	0	808,731	0.0000
General Service Less Than 50 kW	$/kWh	67,469,308		(1)	0.0000	0	14,512,693	0.0000
General Service 50 to 4,999 kW	$/kW	316,941,804	797,792	(3)	0.0000	0	758,304	0.0000
Large Use	$/kW	65,544,852	128,687	(1)	0.0000	0	128,687	0.0000
Unmetered Scattered Load	$/kWh	629,732		(0)	0.0000	0		0.0000
Sentinel Lighting	$/kW	234,690	679	(0)	0.0000	0	0	0.0000
Street Lighting		3,904,130	11,255					
MicroFit								
Total		**600,000,000**	**938,413**	**(6)**		**0**	**43,792,429**	

3RD Generation Incentive Regulation Model for 2013 Filers

Festival Hydro Inc.

If applicable, please enter any adjustments related to the revenue to cost ratio model into columns C and E.
The Price Escalator has been set at the 2012 values and will be updated by Board staff. The Stretch Factor Value will also be updated by Board staff.

Price Escalator	**2.00%**	**Choose Stretch Factor Group**	I
Productivity Factor	**0.72%**	**Associated Stretch Factor Value**	**0.2%**
Price Cap Index	**1.08%**		

Rate Class	**Current MFC**	**MFC Adjustment from R/C Model**	**Current Volumetric Charge**	**DVR Adjustment from R/C Model**	**Price Cap Index to be Applied to MFC and DVR**	**Proposed MFC**	**Proposed Volumetric Charge**
Residential	14.92	-0.03	0.0166		1.08%	15.05	0.0168
Residential - Hensall	13.82	1.07	0.0149	0.0012	1.08%	15.05	0.0163
General Service Less Than 50 kW	28.88		0.0146		1.08%	29.19	0.0148
General Service 50 to 4,999 kW	223.24		2.2889		1.08%	225.65	2.3136
Large Use	10676.92		0.9908		1.08%	10792.23	1.0015
Unmetered Scattered Load	12.79		0.0126		1.08%	12.93	0.0127
Sentinel Lighting	2.02		10.6140		1.08%	2.04	10.7286
Street Lighting	1.08		4.9197		1.08%	1.09	4.9728
MicroFit	5.25					5.25	

Please enter the following charges as found on your most recent Board-Approved Tariff Schedule. The standard Allowance rates have been included as default entries. If you have different rates, please make the appropriate corrections in the applicable cells below. As well, please enter the current Specific Service Charges below. The standard Retail Service Charges have been entered below. If you have different rates, please make the appropriate corrections in columns A, C or D as applicable (cells are unlocked).

ALLOWANCES

	UNIT	CURRENT
Transformer Allowance for Ownership - per kW of billing demand/month	$	0.60
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	1.00

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Income Tax Letter	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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	%	19.66
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After 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 – During Regular Hours	$	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
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean

Energy Benefit and the HST.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0307
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0176
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0204
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0075

Below is a listing of the proposed Monthly Fixed Charges, proposed Distribution Volumetric Rates, proposed Deferral and Variance account Rate Riders and all unexpired volumetric rates that were entered on Sheet 4. In the green cells (column A) below, please enter any additional rates being proposed (eg: LRAM/SSM, Tax Adjustments, etc). Please ensure that the word "Rider" or "Adder" is included in the description (as applicable). Note: All rates with expired effective dates have been removed. As well, the Current RTSR-Network and RTSR-Connection rate descriptions entered on Sheet 4 can be found below. The associated rates have been removed from this sheet, giving the applicant the opportunity to enter updated rates (from Sheet 13 in the Board-Approved RTSR model into the cells in column I.

RESIDENTIAL SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.05
Distribution Volumetric Rate	$/kWh	0.0168
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kWh	0.0006
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	**0.0061**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	**0.0048**
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.9900

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

RESIDENTIAL - HENSALL SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.05
Distribution Volumetric Rate	$/kWh	0.0163
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kWh	0.0006
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	**0.0061**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	**0.0048**
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0008
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.7500

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	29.19
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kWh	0.0001
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	**0.0053**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	**0.0044**
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0010
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	1.9500

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	225.65
Distribution Volumetric Rate	$/kW	2.3136
Low Voltage Service Rate	$/kW	0.0689
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3508)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kW	0.0389
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0254)
Retail Transmission Rate - Network Service Rate	$/kW	**2.2145**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	**1.7422**
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	**2.3520**
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	**1.9099**
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.1518
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	14.8100

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

LARGE USE SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10,792.23
Distribution Volumetric Rate	$/kW	1.0015

Low Voltage Service Rate	$/kW	0.0801
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.4507)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kW	0.1910
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0250)
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	**2.6043**
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	**2.1841**
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.0667
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	718.8800

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	12.93
Distribution Volumetric Rate	$/kWh	0.0127
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	-0.0008
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	**0.0053**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	**0.0044**
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0008
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.8500

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.04
Distribution Volumetric Rate	$/kW	10.7286
Low Voltage Service Rate	$/kW	0.0504
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3881)
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.1138)
Retail Transmission Rate - Network Service Rate	$/kW	**1.6785**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	**1.3751**
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.4975
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.1000

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.09
Distribution Volumetric Rate	$/kW	4.9728
Low Voltage Service Rate	$/kW	0.0494
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.2751)
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0984)
Retail Transmission Rate - Network Service Rate	$/kW	**1.6701**
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	**1.3469**

Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.2344
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.0500

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

MICROFIT SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.25

3RD Generation Incentive Regulation Model for 2013 Filers

Festival Hydro Inc.

The following table provides applicants with a class to class comparison of current vs. proposed rates.

Current Rates

Rate Description	Unit	Amount
Residential		
Service Charge	$	14.92
Distribution Volumetric Rate	$/kWh	0.0166
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kWh	0.0011
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kWh	0.0006
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0005)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012		
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Residential - Hensall		
Service Charge	$	13.82
Distribution Volumetric Rate	$/kWh	0.0149

Proposed Rates

Rate Description	Unit	Amount
Residential		
Service Charge	$	15.05
Distribution Volumetric Rate	$/kWh	0.0168
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kWh	0.0006
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.99
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Residential - Hensall		
Service Charge	$	15.05
Distribution Volumetric Rate	$/kWh	0.0163

Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kWh	0.0007
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kWh	0.0006
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0067
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
General Service Less Than 50 kW		
Service Charge	$	28.88
Distribution Volumetric Rate	$/kWh	0.0146
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kWh	0.0007
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kWh	0.0001
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0058
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
General Service 50 to 4,999 kW		
Service Charge	$	223.24
Distribution Volumetric Rate	$/kW	2.2889
Low Voltage Service Rate	$/kW	0.0689

Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kWh	0.0006
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0008
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.75
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
General Service Less Than 50 kW		
Service Charge	$	29.19
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kWh	0.0001
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0044
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0010
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	1.95
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
General Service 50 to 4,999 kW		
Service Charge	$	225.65
Distribution Volumetric Rate	$/kW	2.3136
Low Voltage Service Rate	$/kW	0.0689

Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3508)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kW	0.0782
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kW	0.0389
Rate Rider for Tax Change – Effective until April 30, 2013	$/kW	(0.0358)
Retail Transmission Rate - Network Service Rate	$/kW	2.4342
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7981
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.5854
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.9712
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	10,676.92
Distribution Volumetric Rate	$/kW	0.9908
Low Voltage Service Rate	$/kW	0.0801
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.4507)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kW	0.0737
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery	$/kW	0.1910
Rate Rider for Tax Change – Effective until April 30, 2013	$/kW	(0.0350)
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.8627
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.2542
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.79

Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3508)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kW	0.0389
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0254)
Retail Transmission Rate - Network Service Rate	$/kW	2.2145
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7422
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.3520
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.9099
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.1518
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	14.81
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	10,792.23
Distribution Volumetric Rate	$/kW	1.0015
Low Voltage Service Rate	$/kW	0.0801
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.4507)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective until April 30, 2014	$/kW	0.1910
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0250)
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.6043
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.1841
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.0667
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	718.88
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	12.93

Distribution Volumetric Rate	$/kWh	0.0126	Distribution Volumetric Rate	$/kWh	0.0127
Low Voltage Service Rate	$/kWh	0.0002	Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0008)	Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kWh	0.0014	Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0004)
Rate Rider for Tax Change – Effective until April 30, 2013	$/kWh	(0.0006)	Retail Transmission Rate - Network Service Rate	$/kWh	0.0053
Retail Transmission Rate - Network Service Rate	$/kWh	0.0058	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0044
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045	Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0008
Wholesale Market Service Rate	$/kWh	0.0052	Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.85
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000	Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011	Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Sentinel Lighting			**Sentinel Lighting**		
Service Charge (per connection)	$	2.02	Service Charge (per connection)	$	2.04
Distribution Volumetric Rate	$/kW	10.6140	Distribution Volumetric Rate	$/kW	10.7286
Low Voltage Service Rate	$/kW	0.0504	Low Voltage Service Rate	$/kW	0.0504
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3881)	Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3881)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kW	0.2723	Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.1138)
Rate Rider for Tax Change – Effective until April 30, 2013	$/kW	(0.1362)	Retail Transmission Rate - Network Service Rate	$/kW	1.6785
Retail Transmission Rate - Network Service Rate	$/kW	1.8451	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3751
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4192	Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.4975
Wholesale Market Service Rate	$/kWh	0.0052	Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.10
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000	Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011	Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25	Standard Supply Service - Administrative Charge (if applicable)	$	0.25
Street Lighting			**Street Lighting**		
Service Charge (per connection)	$	1.08	Service Charge (per connection)	$	1.09
Distribution Volumetric Rate	$/kW	4.9197	Distribution Volumetric Rate	$/kW	4.9728
Low Voltage Service Rate	$/kW	0.0494	Low Voltage Service Rate	$/kW	0.0494
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.2751)	Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.2751)
Rate Rider for Deferral/Variance Account Disposition (2012) – Effective until April 30, 2013	$/kW	0.2411	Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0984)
Rate Rider for Tax Change – Effective until April 30, 2013	$/kW	(0.1191)	Retail Transmission Rate - Network Service Rate	$/kW	1.6701

Retail Transmission Rate - Network Service Rate	$/kW	1.8358
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3901
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge - effective until April 30, 2012	0	0.0000
Rural Rate Protection Charge - effective on and after May 1, 2012	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
MicroFit		
Service Charge	$	5.25

Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3469
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.2344
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.05
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25
MicroFit		
Service Charge	$	5.25

The following is a complete Tariff Schedule based on the information entered in this model. Please review.
Note: This worksheet is **unlocked** and the print margins, row heights, number formats, etc. can be adjusted.

Festival Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 01, 2013

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

EB-2011-0167

RESIDENTIAL SERVICE CLASSIFICATION

A customer is classed as residential when all the following conditions are met:
(a) the property is zoned strictly residential by the local municipality,
(b) the account is created and maintained in the customer's name,
(c) the building is used for dwelling purposes.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.05
Distribution Volumetric Rate	$/kWh	0.0168
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kWh	0.0006
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0011
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.99

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

RESIDENTIAL - HENSALL SERVICE CLASSIFICATION

APPLICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.05
Distribution Volumetric Rate	$/kWh	0.0163
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kWh	0.0006
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0061
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0048
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0008
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.75

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose peak demand is less than 50 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Customers who are classed as General Service but consider themselves eligible to be classed as Residential must provide Festival Hydro with a copy of their tax assessment, which clearly demonstrates the zoning is for residential use only. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	29.19
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kWh	0.0001
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053

Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0044
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0010
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	1.95

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose peak demand is equal to or greater than 50 kW but less than 5,000 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	225.65
Distribution Volumetric Rate	$/kW	2.3136
Low Voltage Service Rate	$/kW	0.0689
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3508)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kW	0.0389
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0254)
Retail Transmission Rate - Network Service Rate	$/kW	2.2145
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7422
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.3520
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.9099
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.1518
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	14.81

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

LARGE USE SERVICE CLASSIFICATION

This classification refers to non-residential accounts whose monthly peak demand is equal to or greater than 5,000 kW, based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10,792.23
Distribution Volumetric Rate	$/kW	1.0015
Low Voltage Service Rate	$/kW	0.0801
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.4507)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery / Shared Savings Mechanism (SSM) Recovery - Effective u	$/kW	0.1910
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0250)
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.6043
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.1841
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.0667
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	718.88

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian Cross-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	12.93
Distribution Volumetric Rate	$/kWh	0.0127
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Tax Change - effective until April 30, 2014	$/kWh	(0.0004)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0053
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0044
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kWh	0.0008

Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.85

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.04
Distribution Volumetric Rate	$/kW	10.7286
Low Voltage Service Rate	$/kW	0.0504
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.3881)
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.1138)
Retail Transmission Rate - Network Service Rate	$/kW	1.6785
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3751
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.4975
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.10

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. If connected to the municipal or the Province of Ontario street lighting system, decorative lighting and tree lighting services will be treated as a Street Lighting class of service. Decorative or tree lighting connected to Festival Hydro Inc.'s distribution system will be treated as a General Service Less Than 50 kW class customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.09
Distribution Volumetric Rate	$/kW	4.9728
Low Voltage Service Rate	$/kW	0.0494
Rate Rider for Deferral/Variance Account Disposition (2010) – Effective until April 30, 2014	$/kW	(0.2751)
Rate Rider for Tax Change - effective until April 30, 2014	$/kW	(0.0984)
Retail Transmission Rate - Network Service Rate	$/kW	1.6701
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3469
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$/kW	0.2344
Rate Rider for Recovery of Incremental Capital Costs- effective until April 30, 2014	$	0.05

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

MICROFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.25

ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Income Tax Letter	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	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	%	19.66
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After 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 – During Regular Hours	$	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
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

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

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

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0307
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0176
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0204
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0075

Choose a Rate Class from the drop-down menu below and click UPDATE.

For Street Lighting and USL classes, please ensure that the number of customers is manually entered into cells B30 and B31.

Click the UPDATE button to refresh the sheet.

Residential

Consumption	800	**kWh**
RPP Tier One	600	**kWh**
Load Factor		
Loss Factor	1.0307	

	CURRENT ESTIMATED BILL			PROPOSED ESTIMATED BILL						
	Volume	Current Rate ($)	Current Charge ($)	Volume	Proposed Rate ($)	Proposed Charge ($)	Change ($)	Change (%)	% of Total RPP Bill	% of Total TOU Bill
Energy First Tier (kWh)	600.00	0.0750	45.00	600.00	0.0750	45.00	0.00	0.00%	38.53%	
Energy Second Tier (kWh)	224.56	0.0880	19.76	224.56	0.0880	19.76	0.00	0.00%	16.92%	
TOU - Off Peak	527.72	0.0650	34.30	527.72	0.0650	34.30	0.00	0.00%		28.93%
TOU - Mid Peak	148.42	0.1000	14.84	148.42	0.1000	14.84	0.00	0.00%		12.52%
TOU - On Peak	148.42	0.1170	17.37	148.42	0.1170	17.37	0.00	0.00%		14.65%
Service Charge	1	14.92	14.92	1	15.05	15.05	0.13	0.87%	12.89%	12.69%
Service Charge Rate Rider(s)	1	0.00	0.00	1	0.99	0.99	0.99	0.00%	0.85%	0.84%
Distribution Volumetric Rate	800	0.0166	13.28	800	0.0168	13.44	0.16	1.20%	11.51%	11.34%
Low Voltage Volumetric Rate	800	0.0002	0.16	800	0.0002	0.16	0.00	0.00%	0.14%	0.13%
Distribution Volumetric Rate Rider(s)	800	0.0003	0.24	800	0.0005	0.40	0.16	65.33%	0.34%	0.33%
Total: Distribution			**28.60**			**30.04**	**1.44**	**5.03%**	**25.72%**	**25.34%**
Retail Transmission Rate - Network Service Rate	824.56	0.0067	5.52	824.56	0.0061	5.03	(0.49)	-8.88%	4.31%	4.24%
Retail Transmission Rate - Line and Transformation Connection Service Rate	824.56	0.005	4.12	824.56	0.0048	3.96	(0.16)	-3.88%	3.39%	3.34%
Total: Retail Transmission			9.64			8.99	(0.65)	(6.74%)	7.70%	7.58%
Sub-Total: Delivery (Distribution and Retail Transmission)			**38.24**			**39.03**	**0.79**	**2.07%**	**33.42%**	**32.92%**
Wholesale Market Service Rate	824.56	0.0052	4.29	824.56	0.0052	4.29	0.00	0.00%	3.67%	3.62%
Rural Rate Protection Charge	824.56	0.0011	0.91	824.56	0.0011	0.91	0.00	0.00%	0.78%	0.77%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.00%	0.21%	0.21%
Sub-Total: Regulatory			**5.44**			**5.44**	**0.00**	0.00%	**4.66%**	**4.59%**
Debt Retirement Charge (DRC)	800.00	0.00700	5.60	800.00	0.0070	**5.60**	0.00	0.00%	**4.79%**	**4.72%**
Total Bill on RPP (before taxes)			114.05			114.84	0.79	0.69%	98.33%	
HST		13%	14.83		13%	14.93	0.10	0.69%	12.78%	
Total Bill (including HST)			128.88			129.77	0.89	0.69%	111.11%	
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(12.89)		(10%)	(12.98)	(0.09)	0.69%	-11.11%	
Total Bill on RPP (including OCEB)			**115.99**			**116.79**	**0.80**	0.69%	**100.00%**	
Total Bill on TOU (before taxes)			115.79			116.58	0.79	0.68%		98.33%
HST		13%	15.05		13%	15.16	0.10	0.68%		12.78%
Total Bill (including HST)			130.84			131.74	0.89	0.68%		111.11%
Ontario Clean Energy Benefit (OCEB)		**(10%)**	(13.08)		(10%)	(13.17)	(0.09)	0.68%		-11.11%
Total Bill on TOU (including OCEB)			**117.76**			**118.56**	**0.80**	0.68%		**100.00%**

APPENDIX D

2013 IRM3 Shared Tax Savings Workform

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

Version 1.0

Utility Name	Festival Hydro Inc.
Assigned EB Number	EB-2012-0124
Name and Title	Debbie Reece
Phone Number	519-271-4703 x268
Email Address	dreece@festivalhydro.com
Date	31-Aug-12
Last COS Re-based Year	**2010**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

Enter your 2012 Base Monthly Fixed Charge and Distribution Volumetric Charge into columns labeled "Rate ReBal Base Service Charge" and "Rate ReBal Base Distribution Volumetric Rate kWh/kW" respectively.

Last COS Re-based Year was in 2010

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	17,115	141,132,375		14.92	0.0166	
RES	Residential - Hensall	Customer	kWh	413	4,143,109		13.82	0.0149	
GSLT50	General Service Less Than 50 kW	Customer	kWh	1,968	67,469,308		28.88	0.0146	
GSGT50	General Service 50 to 4,999 kW	Customer	kW	221	316,941,804	797,792	223.24		2.2889
LU	Large Use	Customer	kW	2	65,544,852	128,687	10,676.92		0.9908
USL	Unmetered Scattered Load	Connection	kWh	156	629,732		12.79	0.0126	
Sen	Sentinel Lighting	Connection	kW	83	234,690	679	2.02		10.6140
SL	Street Lighting	Connection	kW	5,916	3,904,130	11,255	1.08		4.9197
NA	Rate Class 9	NA	NA						
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

Calculating Re-Based Revenue from rates. No input required.

Last COS Re-based Year was in 2010

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I
Residential	17,115	141,132,375	0	14.92	0.0166	0.0000	3,064,270	2,342,797	0	5,407,067
Residential - Hensall	413	4,143,109	0	13.82	0.0149	0.0000	68,492	61,732	0	130,224
General Service Less Than 50 kW	1,968	67,469,308	0	28.88	0.0146	0.0000	682,030	985,052	0	1,667,082
General Service 50 to 4,999 kW	221	316,941,804	797,792	223.24	0.0000	2.2889	592,032	0	1,826,066	2,418,099
Large Use	2	65,544,852	128,687	10,676.92	0.0000	0.9908	256,246	0	127,503	383,749
Unmetered Scattered Load	156	629,732	0	12.79	0.0126	0.0000	23,943	7,935	0	31,878
Sentinel Lighting	83	234,690	679	2.02	0.0000	10.6140	2,012	0	7,207	9,219
Street Lighting	5,916	3,904,130	11,255	1.08	0.0000	4.9197	76,671	0	55,371	132,043
							4,765,696	3,397,516	2,016,147	10,179,360

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

This worksheet calculates the tax sharing amount.

Step 1: Press the Update Button (this will clear all input cells and reveal your latest cost of service re-basing year).
Step 2: In the green input cells below, please enter the information related to the last Cost of Service Filing.

Summary - Sharing of Tax Change Forecast Amounts

For the 2010 year, enter any Tax Credits from the Cost of Service Tax Calculation (Positive #)	$ 24,000	
1. Tax Related Amounts Forecast from Capital Tax Rate Changes	**2010**	**2013**
Taxable Capital	$ 42,140,000	$42,140,000
Deduction from taxable capital up to $15,000,000	$ 15,000,000	$15,000,000
Net Taxable Capital	$ 27,140,000	$27,140,000
Rate	0.150%	0.000%
Ontario Capital Tax (Deductible, not grossed-up)	**$ 20,188**	**$ -**
2. Tax Related Amounts Forecast from Income Tax Rate Changes	**2010**	**2013**
Regulatory Taxable Income	$ 2,026,202	$ 2,026,202
Corporate Tax Rate	29.51%	26.50%
Tax Impact	$ 597,989	$ 512,944
Grossed-up Tax Amount	**$ 848,366**	**$ 697,882**
Tax Related Amounts Forecast from Capital Tax Rate Changes	$ 20,188	$ -
Tax Related Amounts Forecast from Income Tax Rate Changes	$ 848,366	$ 697,882
Total Tax Related Amounts	**$ 868,554**	**$ 697,882**
Incremental Tax Savings		**-$ 170,671**
Sharing of Tax Savings (50%)		**-$ 85,336**

3RD Generation Incentive Regulation Shared Tax Savings Model for 2013 Filers

This worksheet calculates a tax change volumetric rate rider. No input required. The outputs in column Q and S are to be entered into Sheet 11 "Proposed Rates" of the 2013 IRM Rate Generator Model. Rate description should be entered as "Rate Rider for Tax Change".

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Z-Factor Tax Change$ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential	$5,407,067.0250	53.12%	-$45,329	141,132,375	0	-$0.0003	
Residential - Hensall	$130,224	1.28%	-$1,092	4,143,109	0	-$0.0003	
General Service Less Than 50 kW	$1,667,082	16.38%	-$13,975	67,469,308	0	-$0.0002	
General Service 50 to 4,999 kW	$2,418,099	23.75%	-$20,271	316,941,804	797,792		-$0.0254
Large Use	$383,749	3.77%	-$3,217	65,544,852	128,687		-$0.0250
Unmetered Scattered Load	$31,878	0.31%	-$267	629,732	0	-$0.0004	
Sentinel Lighting	$9,219	0.09%	-$77	234,690	679		-$0.1138
Street Lighting	$132,043	1.30%	-$1,107	3,904,130	11,255		-$0.0984
	$10,179,360	100.00%	-$85,336				
	H		-				
			I				

APPENDIX E

2013 IRM3 Revenue Cost Ratio Adjustment Workform

v 2.0

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

Utility Name	Festival Hydro Inc.
Assigned EB Number	EB-2011-0167
Name and Title	Debbie Reece, CFO
Phone Number	519-271-4703 x.268
Email Address	dreece@festivalhydro.com
Date	26-Aug-12
Last COS Re-based Year	**2010**

3^{RD} Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to set up the rate classes, enter the re-based billing determinants from your last cost of service application and enter the current service charge and volumetric distribution rates as found on your May 1, 2012 (or subsequent) Tariff of rates and charges.

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Current Tariff Service Charge D	Current Tariff Distribution Volumetric Rate kWh E	Current Tariff Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	17,115	141,132,375		14.92	0.0166	
RES	Residential - Hensall	Customer	kWh	413	4,143,109		13.82	0.0149	
GSLT50	General Service Less Than 50 kW	Customer	kWh	1,968	67,469,308		28.88	0.0146	
GSGT50	General Service 50 to 4,999 kW	Customer	kW	221	316,941,804	797,792	223.24		2.2889
LU	Large Use	Customer	kW	2	65,544,852	128,687	10,676.92		0.9908
USL	Unmetered Scattered Load	Connection	kWh	156	629,732		12.79	0.0126	
Sen	Sentinel Lighting	Connection	kW	83	234,690	679	2.02		10.6140
SL	Street Lighting	Connection	kW	5,915	3,904,130	11,255	1.08		4.9197
NA	Rate Class 9	NA	NA						
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

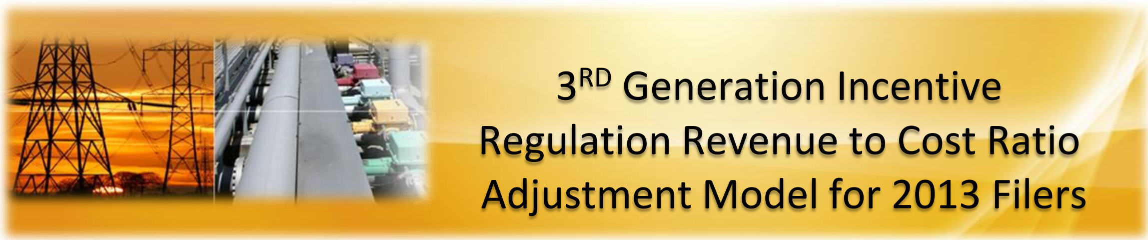
The purpose of this sheet is to remove any rate adders included in current rates. Most applicants will not need to make an entry on this sheet.

Rate Class	Current Tariff Service Charge A	Current Tariff Distribution Volumetric Rate kWh B	Current Tariff Distribution Volumetric Rate kW C	Service Charge Rate Adders D	Distribution Volumetric kWh Rate Adders E	Distribution Volumetric kW Rate Adders F
Residential	14.92	0.0166	0.0000	0.00	0.0000	0.0000
Residential - Hensall	13.82	0.0149	0.0000	0.00	0.0000	0.0000
General Service Less Than 50 kW	28.88	0.0146	0.0000	0.00	0.0000	0.0000
General Service 50 to 4,999 kW	223.24	0.0000	2.2889	0.00	0.0000	0.0000
Large Use	10,676.92	0.0000	0.9908	0.00	0.0000	0.0000
Unmetered Scattered Load	12.79	0.0126	0.0000	0.00	0.0000	0.0000
Sentinel Lighting	2.02	0.0000	10.6140	0.00	0.0000	0.0000
Street Lighting	1.08	0.0000	4.9197	0.00	0.0000	0.0000

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to calculate current revenue from rate classes.

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Current Base Service Charge D	Current Base Distribution Volumetric Rate kWh E	Current Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I
Residential	17,115	141,132,375	0	14.92	0.0166	0.0000	3,064,270	2,342,797	0	5,407,067
Residential - Hensall	413	4,143,109	0	13.82	0.0149	0.0000	68,492	61,732	0	130,224
General Service Less Than 50 kW	1,968	67,469,308	0	28.88	0.0146	0.0000	682,030	985,052	0	1,667,082
General Service 50 to 4,999 kW	221	316,941,804	797,792	223.24	0.0000	2.2889	592,032	0	1,826,066	2,418,099
Large Use	2	65,544,852	128,687	10,676.92	0.0000	0.9908	256,246	0	127,503	383,749
Unmetered Scattered Load	156	629,732	0	12.79	0.0126	0.0000	23,943	7,935	0	31,878
Sentinel Lighting	83	234,690	679	2.02	0.0000	10.6140	2,012	0	7,207	9,219
Street Lighting	5,915	3,904,130	11,255	1.08	0.0000	4.9197	76,658	0	55,371	132,030
							4,765,683	3,397,516	2,016,147	10,179,347



The purpose of this sheet is to enter the Revenue Cost Ratios as determined from column G on Sheet "10. Proposed R C Ratio Adj" of the applicant's 2012 IRM3 Supplemental Filing Module or 2012 COS Decision and Order.

Under the column labeled "Direction", the applicant can choose "No Change" (i.e: no change in that rate class ratio), "Change" (i.e: Board ordered change from COS decision) or "Rebalance" (i.e: to apply any offset adjustments required).

Rate Class	**Direction**	Current Year 2012	Transition Year 1 2013	Transition Year 2 2014	Transition Year 3 2015	Transition Year 4 2016	Transition Year 5 2017
Residential	Rebalance	106.66%	tbd	tbd	tbd	tbd	tbd
Residential - Hensall	Change	99.00%	106.27%	0.00%	0.00%	0.00%	0.00%
General Service Less Than 50 kW	No Change	112.03%	112.03%	112.03%	112.03%	112.03%	112.03%
General Service 50 to 4,999 kW	No Change	81.31%	81.31%	81.31%	81.31%	81.31%	81.31%
Large Use	No Change	112.03%	112.03%	112.03%	112.03%	112.03%	112.03%
Unmetered Scattered Load	No Change	120.00%	120.00%	120.00%	120.00%	120.00%	120.00%
Sentinel Lighting	No Change	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%
Street Lighting	No Change	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%

3^{RD} Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to allocate the Revenue Offsets (miscellaneous revenue, cell F47) found in the last COS to the various rate classes in proportion to the allocation from the Cost Allocation informational filing.

Rate Class	Informational Filing Revenue Offsets	Percentage Split	Allocated Revenue Offsets
	A	C= A / B	E = D * C
Residential	412,176	60.80%	412,176
Residential - Hensall	9,050	1.33%	9,050
General Service Less Than 50 kW	99,107	14.62%	99,107
General Service 50 to 4,999 kW	138,171	20.38%	138,171
Large Use	9,888	1.46%	9,888
Unmetered Scattered Load	2,308	0.34%	2,308
Sentinel Lighting	471	0.07%	471
Street Lighting	6,746	1.00%	6,746
	677,917	100.00%	677,917
	B		D

The purpose of this sheet is to remove the transformer allowance from volumetric rates. In Cell E47, enter your Transformer Allowance as per your 2012 IRM3 Supplemental Filing Module or your last CoS Decision. Under the column labeled "Transformer Allowance in Rates" select "Yes" if included in that rate class or "No" if not included. Once selected, apply the update button to reveal input cells in which you can enter the number of kW's and the transfromer rate for each rate class.

Rate Class	Transformer Allowance In Rate	Transformer Allowance	Transformer Allowance kW's	Transformer Allowance Rate	Volumetric Distribution Rate	Billed kW's	Adjusted Volumetric Distribution Rate
		A	C	E	F	G	I =(F * (G - C) + (F - E) * C) / G
Residential		0	0	0.0000	0.0000	0	0.0000
Residential - Hensall		0	0	0.0000	0.0000	0	0.0000
General Service Less Than 50 kW		0	0	0.0000	0.0000	0	0.0000
General Service 50 to 4,999 kW	Yes	313,728	522,880	0.6000	2.2889	797,792	1.8957
Large Use	Yes	77,212	128,687	0.6000	0.9908	128,687	0.3908
Unmetered Scattered Load		-	-	-	-	-	-
Sentinel Lighting		-	-	-	-	-	-
Street Lighting		-	-	-	-	-	-
		390,940	651,567			926,479	
		B	D			H	
		0					

3^RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

The purpose of this sheet is to calculate revenue by rate class that inlcudes Revenue Offsets and excludes Transformer Allowance prior to Revenue Cost Ratio Adjustment re-allocation.

Rate Class	Billed Customers or Connections A	Billed kWh B	Billed kW C		Base Service Charge D	Base Distribution Volumetric Rate kWh E	Base Distribution Volumetric Rate kW F	Service Charge G = A * D *12	Distribution Volumetric Rate kWh H = B * E	Distribution Volumetric Rate kW I = C * F	Revenue Requirement from Rates J = G + H + I
Residential	17,115	141,132,375	0	0	14.92	0.0166	0.0000	3,064,270	2,342,797	0	5,407,067
Residential - Hensall	413	4,143,109	0	0	13.82	0.0149	0.0000	68,492	61,732	0	130,224
General Service Less Than 50 kW	1,968	67,469,308	0	0	28.88	0.0146	0.0000	682,030	985,052	0	1,667,082
General Service 50 to 4,999 kW	221	316,941,804	797,792	0	223.24	0.0000	1.8957	592,032	0	1,512,338	2,104,371
Large Use	2	65,544,852	128,687	0	10,676.92	0.0000	0.3908	256,246	0	50,291	306,537
Unmetered Scattered Load	156	629,732	0	0	12.79	0.0126	0.0000	23,943	7,935	0	31,878
Sentinel Lighting	83	234,690	679	0	2.02	0.0000	10.6140	2,012	0	7,207	9,219
Street Lighting	5,915	3,904,130	11,255	0	1.08	0.0000	4.9197	76,658	0	55,371	132,030
								4,765,683	3,397,516	1,625,207	9,788,407

3[RD] Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

Proposed Revenue Cost Ratio Adjustment

Rate Class	Adjusted Revenue A	Current Revenue Cost Ratio B	Re-Allocated Cost C = A / B	Proposed Revenue Cost Ratio D	Final Adjusted Revenue E = C * D	Dollar Change F = E - C	Percentage Change G = (E / C) - 1
Residential	$ 5,819,243	1.07	$ 5,455,881	1.06	$ 5,809,013	-$ 10,230	-0.2%
Residential - Hensall	$ 139,274	0.99	$ 140,681	1.06	$ 149,502	$ 10,228	7.3%
General Service Less Than 50 kW	$ 1,766,189	1.12	$ 1,576,532	1.12	$ 1,766,189	$ 0	0.0%
General Service 50 to 4,999 kW	$ 2,242,542	0.81	$ 2,758,014	0.81	$ 2,242,542	-$ 0	0.0%
Large Use	$ 316,425	1.12	$ 282,447	1.12	$ 316,425	$ 0	0.0%
Unmetered Scattered Load	$ 34,186	1.20	$ 28,488	1.20	$ 34,186	$ 0	0.0%
Sentinel Lighting	$ 9,690	0.70	$ 13,843	0.70	$ 9,690	-$ 0	0.0%
Street Lighting	$ 138,776	0.70	$ 198,251	0.70	$ 138,776	-$ 0	0.0%
	$ 10,466,324		$ 10,454,137		$ 10,466,322	-$ 2	0.0%

Out of Balance	**2**
Final ?	Yes

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

Proposed Revenue from Revenue Cost Ratio Adjustment

Rate Class	Adjusted Revenue By Revenue Cost Ratio	Allocated Re-Based Revenue Offsets	Revenue Requirement from Rates Before Transformer Allowance	Re-based Transformer Allowance	Revenue Requirement from Rates
	A	B	C = A - B	D	E = C + D
Residential	$ 5,809,013	$ 412,176	$ 5,396,837	$ -	$ 5,396,837
Residential - Hensall	$ 149,502	$ 9,050	$ 140,452	$ -	$ 140,452
General Service Less Than 50 kW	$ 1,766,189	$ 99,107	$ 1,667,082	$ -	$ 1,667,082
General Service 50 to 4,999 kW	$ 2,242,542	$ 138,171	$ 2,104,371	$ 313,728	$ 2,418,099
Large Use	$ 316,425	$ 9,888	$ 306,537	$ 77,212	$ 383,749
Unmetered Scattered Load	$ 34,186	$ 2,308	$ 31,878	$ -	$ 31,878
Sentinel Lighting	$ 9,690	$ 471	$ 9,219	$ -	$ 9,219
Street Lighting	$ 138,776	$ 6,746	$ 132,030	$ -	$ 132,030
	$ 10,466,322	$ 677,917	$ 9,788,405	$ 390,940	$ 10,179,345

Proposed fixed and variable revenue allocation

Rate Class	Revenue Requirement from Rates A	Service Charge % Revenue B	Distribution Volumetric Rate % Revenue kWh C	Distribution Volumetric Rate % Revenue kW D	Service Charge Revenue E = A * B	Distribution Volumetric Rate Revenue kWh F = A * C	Distribution Volumetric Rate Revenue kW G = A * D	Revenue Requirement from Rates by Rate Class H = E + F + G
Residential	$ 5,396,837	56.7%	43.3%	0.0%	$ 3,058,472	$ 2,338,365	$ -	$ 5,396,837
Residential - Hensall	$ 140,452	52.6%	47.4%	0.0%	$ 73,871	$ 66,581	$ -	$ 140,452
General Service Less Than 50 kW	$ 1,667,082	40.9%	59.1%	0.0%	$ 682,030	$ 985,052	$ -	$ 1,667,082
General Service 50 to 4,999 kW	$ 2,418,099	24.5%	0.0%	75.5%	$ 592,032	$ -	$ 1,826,066	$ 2,418,099
Large Use	$ 383,749	66.8%	0.0%	33.2%	$ 256,246	$ -	$ 127,503	$ 383,749
Unmetered Scattered Load	$ 31,878	75.1%	24.9%	0.0%	$ 23,943	$ 7,935	$ -	$ 31,878
Sentinel Lighting	$ 9,219	21.8%	0.0%	78.2%	$ 2,012	$ -	$ 7,207	$ 9,219
Street Lighting	$ 132,030	58.1%	0.0%	41.9%	$ 76,658	$ -	$ 55,371	$ 132,030
	$ 10,179,345				$ 4,765,265	$ 3,397,932	$ 2,016,147	$ 10,179,345

3^{RD} Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

Proposed fixed and variable rates

Rate Class	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Proposed Base Service Charge	Proposed Base Distribution Volumetric Rate kWh	Proposed Base Distribution Volumetric Rate kW
	A	B	C	D	E	F	G = A / D / 12	H = B / E	I = C / F
Residential	$ 3,058,472	$ 2,338,365	$ -	17,115	141,132,375	0	14.89	0.0166	-
Residential - Hensall	$ 73,871	$ 66,581	$ -	413	4,143,109	0	14.91	0.0161	-
General Service Less Than 50 kW	$ 682,030	$ 985,052	$ -	1,968	67,469,308	0	28.88	0.0146	-
General Service 50 to 4,999 kW	$ 592,032	$ -	$ 1,826,066	221	316,941,804	797,792	223.24	-	2.2889
Large Use	$ 256,246	$ -	$ 127,503	2	65,544,852	128,687	10,676.92	-	0.9908
Unmetered Scattered Load	$ 23,943	$ 7,935	$ -	156	629,732	0	12.79	0.0126	-
Sentinel Lighting	$ 2,012	$ -	$ 7,207	83	234,690	679	2.02	-	10.6140
Street Lighting	$ 76,658	$ -	$ 55,371	5,915	3,904,130	11,255	1.08	-	4.9197

3RD Generation Incentive Regulation Revenue to Cost Ratio Adjustment Model for 2013 Filers

Proposed adjustments to Base Service Charge and Distribution Volumetric Rate. Enter the adjustments found in column M and N below into Sheet 9 of the 2013 IRM Rate Generator Model.

Rate Class	Proposed Base Service Charge	Proposed Base Distribution Volumetric Rate kWh	Proposed Base Distribution Volumetric Rate kW	Current Base Service Charge	Current Base Distribution Volumetric Rate kWh	Current Base Distribution Volumetric Rate kW	Adjustment Required Base Service Charge	Adjustment Required Base Distribution Volumetric Rate kWh	Adjustment Required Base Distribution Volumetric Rate kW
	A	B	C	D	E	F	G = A - D	H = B - E	I = C - F
Residential	$ 14.89	$ 0.0166	$ -	$ 14.92	$ 0.0166	$ -	-$ 0.03	-$ 0.0000	$ -
Residential - Hensall	$ 14.91	$ 0.0161	$ -	$ 13.82	$ 0.0149	$ -	$ 1.09	$ 0.0012	$ -
General Service Less Than 50 kW	$ 28.88	$ 0.0146	$ -	$ 28.88	$ 0.0146	$ -	$ -	$ -	$ -
General Service 50 to 4,999 kW	$ 223.24	$ -	$ 2.2889	$ 223.24	$ -	$ 2.2889	$ -	$ -	$ -
Large Use	$ 10,676.92	$ -	$ 0.9908	$ 10,676.92	$ -	$ 0.9908	$ -	$ -	$ -
Unmetered Scattered Load	$ 12.79	$ 0.0126	$ -	$ 12.79	$ 0.0126	$ -	$ -	$ -	$ -
Sentinel Lighting	$ 2.02	$ -	$ 10.6140	$ 2.02	$ -	$ 10.6140	$ -	$ -	$ -
Street Lighting	$ 1.08	$ -	$ 4.9197	$ 1.08	$ -	$ 4.9197	$ -	$ -	$ -

APPENDIX F

2013 IRM3 RTSR Adjustment Workform

v 3.0

RTSR Workform for Electricity Distributors (2013 Filers)

Utility Name	Festival Hydro Inc.
Assigned EB Number	EB-2012-0124
Name and Title	Debbie Reece
Phone Number	519-271-4703 x268
Email Address	dreece@festivalhydro.com
Date	31-Aug-12
Last COS Re-based Year	**2010**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

RTSR Workform for Electricity Distributors (2013 Filers)

RTSR Workform for Electricity Distributors (2013 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	$ 0.0067	$ 0.0050
Residential - Hensall	kWh	$ 0.0067	$ 0.0050
General Service Less Than 50 kW	kWh	$ 0.0058	$ 0.0045
General Service 50 to 4,999 kW	kW	$ 2.4342	$ 1.7981
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.5854	$ 1.9712
Large Use	kW	$ 2.8627	$ 2.2542
Unmetered Scattered Load	kWh	$ 0.0058	$ 0.0045
Sentinel Lighting	kW	$ 1.8451	$ 1.4192
Street Lighting	kW	$ 1.8358	$ 1.3901
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
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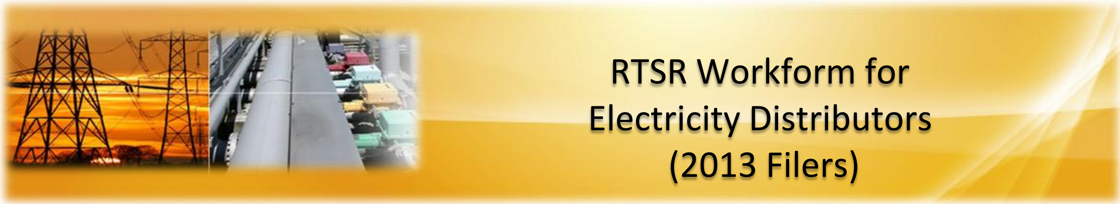
Choose Rate Class			
Choose Rate Class			



In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	kWh	137,110,454		1.0307		141,319,745	-
Residential - Hensall	kWh	3,814,545		1.0307		3,931,652	-
General Service Less Than 50 kW	kWh	63,567,429		1.0307		65,518,949	-
General Service 50 to 4,999 kW	kW	47,345,637	132,852		**48.85%**	47,345,637	132,852
General Service 50 to 4,999 kW – Interval Metered	kW	295,051,789	760,654		**53.17%**	295,051,789	760,654
Large Use	kW	30,589,560	59,443		**70.53%**	30,589,560	59,443
Unmetered Scattered Load	kWh	666,441		1.0307		686,901	-
Sentinel Lighting	kW	200,336	556		**49.39%**	200,336	556
Street Lighting	kW	4,206,123	11,209		**51.43%**	4,206,123	11,209

RTSR Workform for Electricity Distributors (2013 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	**$ 3.22**	**$ 3.57**	**$ 3.22**
Line Connection Service Rate	kW	**$ 0.79**	**$ 0.80**	**$ 0.79**
Transformation Connection Service Rate	kW	**$ 1.77**	**$ 1.86**	**$ 1.77**

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	**$ 2.65**	**$ 2.65**	**$ 2.65**
Line Connection Service Rate	kW	**$ 0.64**	**$ 0.64**	**$ 0.64**
Transformation Connection Service Rate	kW	**$ 1.50**	**$ 1.50**	**$ 1.50**
Both Line and Transformation Connection Service Rate	kW	**$ 2.14**	**$ 2.14**	**$ 2.14**

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	**$ 0.0470**	**$ -**	**$ -**
RSVA Transmission connection – 4716 – which affects 1586	kW	**-$ 0.0250**	**$ -**	**$ -**
RSVA LV – 4750 – which affects 1550	kW	**$ 0.0580**	**$ -**	**$ -**
RARA 1 – 2252 – which affects 1590	kW	**-$ 0.0750**	**$ -**	**$ -**
Hydro One Sub-Transmission Rate Rider 6A	kW	**$ 0.0050**	**$ -**	**$ -**

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing deteminants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	82,984	$3.22	$ 267,208	84,267	$0.79	$ 66,571	84,267	$1.77	$ 149,153	$ 215,724
February	80,989	$3.22	$ 260,785	82,994	$0.79	$ 65,565	82,994	$1.77	$ 146,899	$ 212,465
March	79,160	$3.22	$ 254,895	79,538	$0.79	$ 62,835	79,538	$1.77	$ 140,782	$ 203,617
April	76,520	$3.22	$ 246,394	77,604	$0.79	$ 61,307	77,604	$1.77	$ 137,359	$ 198,666
May	84,109	$3.22	$ 270,831	87,134	$0.79	$ 68,836	87,134	$1.77	$ 154,227	$ 223,063
June	88,668	$3.22	$ 285,511	91,643	$0.79	$ 72,398	91,643	$1.77	$ 162,208	$ 234,606
July	97,275	$3.22	$ 313,226	98,463	$0.79	$ 77,786	98,463	$1.77	$ 174,280	$ 252,065
August	80,802	$3.22	$ 260,182	85,116	$0.79	$ 67,242	85,116	$1.77	$ 150,655	$ 217,897
September	85,818	$3.22	$ 276,334	85,841	$0.79	$ 67,814	85,841	$1.77	$ 151,939	$ 219,753
October	73,567	$3.22	$ 236,886	79,229	$0.79	$ 62,591	79,229	$1.77	$ 140,235	$ 202,826
November	80,326	$3.22	$ 258,650	81,660	$0.79	$ 64,511	81,660	$1.77	$ 144,538	$ 209,050
December	79,865	$3.22	$ 257,165	83,336	$0.79	$ 65,835	83,336	$1.77	$ 147,505	$ 213,340
Total	990,083	$ 3.22	$ 3,188,067	1,016,825	$ 0.79	$ 803,292	1,016,825	$ 1.77	$ 1,799,780	$ 2,603,072

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	10,651	$2.65	$ 28,225	10,651	$0.64	$ 6,817	8,928	$1.50	$ 13,392	$ 20,209
February	10,426	$2.65	$ 27,629	10,426	$0.64	$ 6,673	8,770	$1.50	$ 13,155	$ 19,828
March	9,904	$2.65	$ 26,246	9,913	$0.64	$ 6,344	8,452	$1.50	$ 12,678	$ 19,022
April	8,966	$2.65	$ 23,760	9,007	$0.64	$ 5,764	7,701	$1.50	$ 11,552	$ 17,316
May	8,443	$2.65	$ 22,374	8,454	$0.64	$ 5,411	7,070	$1.50	$ 10,605	$ 16,016
June	9,146	$2.65	$ 24,237	9,146	$0.64	$ 5,853	7,616	$1.50	$ 11,424	$ 17,277
July	10,090	$2.65	$ 26,739	10,090	$0.64	$ 6,458	8,345	$1.50	$ 12,518	$ 18,975
August	8,463	$2.65	$ 22,427	8,537	$0.64	$ 5,464	7,127	$1.50	$ 10,691	$ 16,154
September	9,024	$2.65	$ 23,914	9,024	$0.64	$ 5,775	7,550	$1.50	$ 11,325	$ 17,100
October	9,648	$2.65	$ 25,567	9,648	$0.64	$ 6,175	8,416	$1.50	$ 12,624	$ 18,799
November	10,117	$2.65	$ 26,810	10,117	$0.64	$ 6,475	8,680	$1.50	$ 13,020	$ 19,495
December	9,958	$2.65	$ 26,389	9,958	$0.64	$ 6,373	8,390	$1.50	$ 12,585	$ 18,958
Total	114,836	$ 2.65	$ 304,315	114,971	$ 0.64	$ 73,581	97,045	$ 1.50	$ 145,568	$ 219,149

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	93,635	$3.16	$ 295,434	94,918	$0.77	$ 73,388	93,195	$1.74	$ 162,545	$ 235,932
February	91,415	$3.15	$ 288,413	93,420	$0.77	$ 72,238	91,764	$1.74	$ 160,054	$ 232,292
March	89,064	$3.16	$ 281,141	89,451	$0.77	$ 69,179	87,990	$1.74	$ 153,460	$ 222,640
April	85,486	$3.16	$ 270,154	86,611	$0.77	$ 67,072	85,305	$1.75	$ 148,911	$ 215,982
May	92,552	$3.17	$ 293,205	95,588	$0.78	$ 74,246	94,204	$1.75	$ 164,832	$ 239,079
June	97,814	$3.17	$ 309,748	100,789	$0.78	$ 78,251	99,259	$1.75	$ 173,632	$ 251,884
July	107,365	$3.17	$ 339,964	108,553	$0.78	$ 84,243	106,808	$1.75	$ 186,797	$ 271,040
August	89,265	$3.17	$ 282,609	93,653	$0.78	$ 72,705	92,243	$1.75	$ 161,346	$ 234,051
September	94,842	$3.17	$ 300,248	94,865	$0.78	$ 73,590	93,391	$1.75	$ 163,264	$ 236,853
October	83,215	$3.15	$ 262,453	88,877	$0.77	$ 68,766	87,645	$1.74	$ 152,859	$ 221,625
November	90,443	$3.16	$ 285,460	91,777	$0.77	$ 70,986	90,340	$1.74	$ 157,558	$ 228,544
December	89,823	$3.16	$ 283,554	93,294	$0.77	$ 72,209	91,726	$1.75	$ 160,090	$ 232,298
Total	1,104,919	$ 3.16	$ 3,492,383	1,131,796	$ 0.77	$ 876,873	1,113,870	$ 1.75	$ 1,945,348	$ 2,822,221

The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	82,984	$ 3.5700	$ 296,253	84,267	$ 0.8000	$ 67,414	84,267	$ 1.8600	$ 156,737	$ 224,150
February	80,989	$ 3.5700	$ 289,131	82,994	$ 0.8000	$ 66,395	82,994	$ 1.8600	$ 154,369	$ 220,764
March	79,160	$ 3.5700	$ 282,601	79,538	$ 0.8000	$ 63,630	79,538	$ 1.8600	$ 147,941	$ 211,571
April	76,520	$ 3.5700	$ 273,176	77,604	$ 0.8000	$ 62,083	77,604	$ 1.8600	$ 144,343	$ 206,427
May	84,109	$ 3.5700	$ 300,269	87,134	$ 0.8000	$ 69,707	87,134	$ 1.8600	$ 162,069	$ 231,776
June	88,668	$ 3.5700	$ 316,545	91,643	$ 0.8000	$ 73,314	91,643	$ 1.8600	$ 170,456	$ 243,770
July	97,275	$ 3.5700	$ 347,272	98,463	$ 0.8000	$ 78,770	98,463	$ 1.8600	$ 183,141	$ 261,912
August	80,802	$ 3.5700	$ 288,463	85,116	$ 0.8000	$ 68,093	85,116	$ 1.8600	$ 158,316	$ 226,409
September	85,818	$ 3.5700	$ 306,370	85,841	$ 0.8000	$ 68,673	85,841	$ 1.8600	$ 159,664	$ 228,337
October	73,567	$ 3.5700	$ 262,634	79,229	$ 0.8000	$ 63,383	79,229	$ 1.8600	$ 147,366	$ 210,749
November	80,326	$ 3.5700	$ 286,764	81,660	$ 0.8000	$ 65,328	81,660	$ 1.8600	$ 151,888	$ 217,216
December	79,865	$ 3.5700	$ 285,118	83,336	$ 0.8000	$ 66,669	83,336	$ 1.8600	$ 155,005	$ 221,674
Total	990,083	$ 3.57	$ 3,534,596	1,016,825	$ 0.80	$ 813,460	1,016,825	$ 1.86	$ 1,891,295	$ 2,704,755

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	10,651	$ 2.6500	$ 28,225	10,651	$ 0.6400	$ 6,817	8,928	$ 1.5000	$ 13,392	$ 20,209
February	10,426	$ 2.6500	$ 27,629	10,426	$ 0.6400	$ 6,673	8,770	$ 1.5000	$ 13,155	$ 19,828
March	9,904	$ 2.6500	$ 26,246	9,913	$ 0.6400	$ 6,344	8,452	$ 1.5000	$ 12,678	$ 19,022
April	8,966	$ 2.6500	$ 23,760	9,007	$ 0.6400	$ 5,764	7,701	$ 1.5000	$ 11,552	$ 17,316
May	8,443	$ 2.6500	$ 22,374	8,454	$ 0.6400	$ 5,411	7,070	$ 1.5000	$ 10,605	$ 16,016
June	9,146	$ 2.6500	$ 24,237	9,146	$ 0.6400	$ 5,853	7,616	$ 1.5000	$ 11,424	$ 17,277
July	10,090	$ 2.6500	$ 26,739	10,090	$ 0.6400	$ 6,458	8,345	$ 1.5000	$ 12,518	$ 18,975
August	8,463	$ 2.6500	$ 22,427	8,537	$ 0.6400	$ 5,464	7,127	$ 1.5000	$ 10,691	$ 16,154
September	9,024	$ 2.6500	$ 23,914	9,024	$ 0.6400	$ 5,775	7,550	$ 1.5000	$ 11,325	$ 17,100
October	9,648	$ 2.6500	$ 25,567	9,648	$ 0.6400	$ 6,175	8,416	$ 1.5000	$ 12,624	$ 18,799
November	10,117	$ 2.6500	$ 26,810	10,117	$ 0.6400	$ 6,475	8,680	$ 1.5000	$ 13,020	$ 19,495
December	9,958	$ 2.6500	$ 26,389	9,958	$ 0.6400	$ 6,373	8,390	$ 1.5000	$ 12,585	$ 18,958
Total	114,836	$ 2.65	$ 304,315	114,971	$ 0.64	$ 73,581	97,045	$ 1.50	$ 145,568	$ 219,149

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	93,635	$ 3.47	$ 324,478	94,918	$ 0.78	$ 74,230	93,195	$ 1.83	$ 170,129	$ 244,359
February	91,415	$ 3.47	$ 316,760	93,420	$ 0.78	$ 73,068	91,764	$ 1.83	$ 167,524	$ 240,592
March	89,064	$ 3.47	$ 308,847	89,451	$ 0.78	$ 69,975	87,990	$ 1.83	$ 160,619	$ 230,593
April	85,486	$ 3.47	$ 296,936	86,611	$ 0.78	$ 67,848	85,305	$ 1.83	$ 155,895	$ 223,743
May	92,552	$ 3.49	$ 322,643	95,588	$ 0.79	$ 75,118	94,204	$ 1.83	$ 172,674	$ 247,792
June	97,814	$ 3.48	$ 340,782	100,789	$ 0.79	$ 79,168	99,259	$ 1.83	$ 181,880	$ 261,048
July	107,365	$ 3.48	$ 374,010	108,553	$ 0.79	$ 85,228	106,808	$ 1.83	$ 195,659	$ 280,887
August	89,265	$ 3.48	$ 310,890	93,653	$ 0.79	$ 73,556	92,243	$ 1.83	$ 169,006	$ 242,563
September	94,842	$ 3.48	$ 330,284	94,865	$ 0.78	$ 74,448	93,391	$ 1.83	$ 170,989	$ 245,437
October	83,215	$ 3.46	$ 288,201	88,877	$ 0.78	$ 69,558	87,645	$ 1.83	$ 159,990	$ 229,548
November	90,443	$ 3.47	$ 313,574	91,777	$ 0.78	$ 71,803	90,340	$ 1.83	$ 164,908	$ 236,710
December	89,823	$ 3.47	$ 311,507	93,294	$ 0.78	$ 73,042	91,726	$ 1.83	$ 167,590	$ 240,632
Total	1,104,919	$ 3.47	$ 3,838,912	1,131,796	$ 0.78	$ 887,041	1,113,870	$ 1.83	$ 2,036,862	$ 2,923,903

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	82,984	$ 3.2200	$ 267,208	84,267	$ 0.7900	$ 66,571	84,267	$ 1.7700	$ 149,153	$ 215,724
February	80,989	$ 3.2200	$ 260,785	82,994	$ 0.7900	$ 65,565	82,994	$ 1.7700	$ 146,899	$ 212,465
March	79,160	$ 3.2200	$ 254,895	79,538	$ 0.7900	$ 62,835	79,538	$ 1.7700	$ 140,782	$ 203,617
April	76,520	$ 3.2200	$ 246,394	77,604	$ 0.7900	$ 61,307	77,604	$ 1.7700	$ 137,359	$ 198,666
May	84,109	$ 3.2200	$ 270,831	87,134	$ 0.7900	$ 68,836	87,134	$ 1.7700	$ 154,227	$ 223,063
June	88,668	$ 3.2200	$ 285,511	91,643	$ 0.7900	$ 72,398	91,643	$ 1.7700	$ 162,208	$ 234,606
July	97,275	$ 3.2200	$ 313,226	98,463	$ 0.7900	$ 77,786	98,463	$ 1.7700	$ 174,280	$ 252,065
August	80,802	$ 3.2200	$ 260,182	85,116	$ 0.7900	$ 67,242	85,116	$ 1.7700	$ 150,655	$ 217,897
September	85,818	$ 3.2200	$ 276,334	85,841	$ 0.7900	$ 67,814	85,841	$ 1.7700	$ 151,939	$ 219,753
October	73,567	$ 3.2200	$ 236,886	79,229	$ 0.7900	$ 62,591	79,229	$ 1.7700	$ 140,235	$ 202,826
November	80,326	$ 3.2200	$ 258,650	81,660	$ 0.7900	$ 64,511	81,660	$ 1.7700	$ 144,538	$ 209,050
December	79,865	$ 3.2200	$ 257,165	83,336	$ 0.7900	$ 65,835	83,336	$ 1.7700	$ 147,505	$ 213,340
Total	990,083	$ 3.22	$ 3,188,067	1,016,825	$ 0.79	$ 803,292	1,016,825	$ 1.77	$ 1,799,780	$ 2,603,072

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	10,651	$ 2.6500	$ 28,225	10,651	$ 0.6400	$ 6,817	8,928	$ 1.5000	$ 13,392	$ 20,209
February	10,426	$ 2.6500	$ 27,629	10,426	$ 0.6400	$ 6,673	8,770	$ 1.5000	$ 13,155	$ 19,828
March	9,904	$ 2.6500	$ 26,246	9,913	$ 0.6400	$ 6,344	8,452	$ 1.5000	$ 12,678	$ 19,022
April	8,966	$ 2.6500	$ 23,760	9,007	$ 0.6400	$ 5,764	7,701	$ 1.5000	$ 11,552	$ 17,316
May	8,443	$ 2.6500	$ 22,374	8,454	$ 0.6400	$ 5,411	7,070	$ 1.5000	$ 10,605	$ 16,016
June	9,146	$ 2.6500	$ 24,237	9,146	$ 0.6400	$ 5,853	7,616	$ 1.5000	$ 11,424	$ 17,277
July	10,090	$ 2.6500	$ 26,739	10,090	$ 0.6400	$ 6,458	8,345	$ 1.5000	$ 12,518	$ 18,975
August	8,463	$ 2.6500	$ 22,427	8,537	$ 0.6400	$ 5,464	7,127	$ 1.5000	$ 10,691	$ 16,154
September	9,024	$ 2.6500	$ 23,914	9,024	$ 0.6400	$ 5,775	7,550	$ 1.5000	$ 11,325	$ 17,100
October	9,648	$ 2.6500	$ 25,567	9,648	$ 0.6400	$ 6,175	8,416	$ 1.5000	$ 12,624	$ 18,799
November	10,117	$ 2.6500	$ 26,810	10,117	$ 0.6400	$ 6,475	8,680	$ 1.5000	$ 13,020	$ 19,495
December	9,958	$ 2.6500	$ 26,389	9,958	$ 0.6400	$ 6,373	8,390	$ 1.5000	$ 12,585	$ 18,958
Total	114,836	$ 2.65	$ 304,315	114,971	$ 0.64	$ 73,581	97,045	$ 1.50	$ 145,568	$ 219,149

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	93,635	$ 3.16	$ 295,434	94,918	$ 0.77	$ 73,388	93,195	$ 1.74	$ 162,545	$ 235,932
February	91,415	$ 3.15	$ 288,413	93,420	$ 0.77	$ 72,238	91,764	$ 1.74	$ 160,054	$ 232,292
March	89,064	$ 3.16	$ 281,141	89,451	$ 0.77	$ 69,179	87,990	$ 1.74	$ 153,460	$ 222,640
April	85,486	$ 3.16	$ 270,154	86,611	$ 0.77	$ 67,072	85,305	$ 1.75	$ 148,911	$ 215,982
May	92,552	$ 3.17	$ 293,205	95,588	$ 0.78	$ 74,246	94,204	$ 1.75	$ 164,832	$ 239,079
June	97,814	$ 3.17	$ 309,748	100,789	$ 0.78	$ 78,251	99,259	$ 1.75	$ 173,632	$ 251,884
July	107,365	$ 3.17	$ 339,964	108,553	$ 0.78	$ 84,243	106,808	$ 1.75	$ 186,797	$ 271,040
August	89,265	$ 3.17	$ 282,609	93,653	$ 0.78	$ 72,705	92,243	$ 1.75	$ 161,346	$ 234,051
September	94,842	$ 3.17	$ 300,248	94,865	$ 0.78	$ 73,590	93,391	$ 1.75	$ 163,264	$ 236,853
October	83,215	$ 3.15	$ 262,453	88,877	$ 0.77	$ 68,766	87,645	$ 1.74	$ 152,859	$ 221,625
November	90,443	$ 3.16	$ 285,460	91,777	$ 0.77	$ 70,986	90,340	$ 1.74	$ 157,558	$ 228,544
December	89,823	$ 3.16	$ 283,554	93,294	$ 0.77	$ 72,209	91,726	$ 1.75	$ 160,090	$ 232,298
Total	1,104,919	$ 3.16	$ 3,492,383	1,131,796	$ 0.77	$ 876,873	1,113,870	$ 1.75	$ 1,945,348	$ 2,822,221

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0067	141,319,745	-	$ 946,842	24.7%	$ 946,837	$ 0.0067
Residential - Hensall	kWh	$ 0.0067	3,931,652	-	$ 26,342	0.7%	$ 26,342	$ 0.0067
General Service Less Than 50 kW	kWh	$ 0.0058	65,518,949	-	$ 380,010	9.9%	$ 380,008	$ 0.0058
General Service 50 to 4,999 kW	kW	$ 2.4342	47,345,637	132,852	$ 323,388	8.4%	$ 323,387	$ 2.4342
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.5854	295,051,789	760,654	$ 1,966,595	51.2%	$ 1,966,584	$ 2.5854
Large Use	kW	$ 2.8627	30,589,560	59,443	$ 170,167	4.4%	$ 170,167	$ 2.8627
Unmetered Scattered Load	kWh	$ 0.0058	686,901	-	$ 3,984	0.1%	$ 3,984	$ 0.0058
Sentinel Lighting	kW	$ 1.8451	200,336	556	$ 1,026	0.0%	$ 1,026	$ 1.8451
Street Lighting	kW	$ 1.8358	4,206,123	11,209	$ 20,577	0.5%	$ 20,577	$ 1.8358
					$ 3,838,932			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0050	141,319,745	-	$ 706,599	24.3%	$ 709,284	$ 0.0050
Residential - Hensall	kWh	$ 0.0050	3,931,652	-	$ 19,658	0.7%	$ 19,733	$ 0.0050
General Service Less Than 50 kW	kWh	$ 0.0045	65,518,949	-	$ 294,835	10.1%	$ 295,956	$ 0.0045
General Service 50 to 4,999 kW	kW	$ 1.7981	47,345,637	132,852	$ 238,881	8.2%	$ 239,789	$ 1.8049
General Service 50 to 4,999 kW – Interval Metered	kW	$ 1.9712	295,051,789	760,654	$ 1,499,401	51.5%	$ 1,505,100	$ 1.9787
Large Use	kW	$ 2.2542	30,589,560	59,443	$ 133,996	4.6%	$ 134,506	$ 2.2628
Unmetered Scattered Load	kWh	$ 0.0045	686,901	-	$ 3,091	0.1%	$ 3,103	$ 0.0045
Sentinel Lighting	kW	$ 1.4192	200,336	556	$ 789	0.0%	$ 792	$ 1.4246
Street Lighting	kW	$ 1.3901	4,206,123	11,209	$ 15,582	0.5%	$ 15,641	$ 1.3954
					$ 2,912,833			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0067	141,319,745	-	$ 946,837	24.7%	$ 861,369	$ 0.0061
Residential - Hensall	kWh	$ 0.0067	3,931,652	-	$ 26,342	0.7%	$ 23,964	$ 0.0061
General Service Less Than 50 kW	kWh	$ 0.0058	65,518,949	-	$ 380,008	9.9%	$ 345,705	$ 0.0053
General Service 50 to 4,999 kW	kW	$ 2.4342	47,345,637	132,852	$ 323,387	8.4%	$ 294,195	$ 2.2145
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.5854	295,051,789	760,654	$ 1,966,584	51.2%	$ 1,789,066	$ 2.3520
Large Use	kW	$ 2.8627	30,589,560	59,443	$ 170,167	4.4%	$ 154,806	$ 2.6043
Unmetered Scattered Load	kWh	$ 0.0058	686,901	-	$ 3,984	0.1%	$ 3,624	$ 0.0053
Sentinel Lighting	kW	$ 1.8451	200,336	556	$ 1,026	0.0%	$ 933	$ 1.6785
Street Lighting	kW	$ 1.8358	4,206,123	11,209	$ 20,577	0.5%	$ 18,720	$ 1.6701
					$ 3,838,912			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0050	141,319,745	-	$ 709,284	24.3%	$ 684,618	$ 0.0048
Residential - Hensall	kWh	$ 0.0050	3,931,652	-	$ 19,733	0.7%	$ 19,047	$ 0.0048
General Service Less Than 50 kW	kWh	$ 0.0045	65,518,949	-	$ 295,956	10.1%	$ 285,664	$ 0.0044
General Service 50 to 4,999 kW	kW	$ 1.8049	47,345,637	132,852	$ 239,789	8.2%	$ 231,450	$ 1.7422
General Service 50 to 4,999 kW – Interval Metered	kW	$ 1.9787	295,051,789	760,654	$ 1,505,100	51.5%	$ 1,452,758	$ 1.9099
Large Use	kW	$ 2.2628	30,589,560	59,443	$ 134,506	4.6%	$ 129,828	$ 2.1841
Unmetered Scattered Load	kWh	$ 0.0045	686,901	-	$ 3,103	0.1%	$ 2,995	$ 0.0044
Sentinel Lighting	kW	$ 1.4246	200,336	556	$ 792	0.0%	$ 765	$ 1.3751
Street Lighting	kW	$ 1.3954	4,206,123	11,209	$ 15,641	0.5%	$ 15,097	$ 1.3469
					$ 2,923,903			

RTSR Workform for Electricity Distributors (2013 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I. Please note that the rate description for the RTSRs has been transfered to Sheet 11, Column A from Sheet 4.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0061	$ 0.0048
Residential - Hensall	kWh	$ 0.0061	$ 0.0048
General Service Less Than 50 kW	kWh	$ 0.0053	$ 0.0044
General Service 50 to 4,999 kW	kW	$ 2.2145	$ 1.7422
General Service 50 to 4,999 kW – Interval Metered	kW	$ 2.3520	$ 1.9099
Large Use	kW	$ 2.6043	$ 2.1841
Unmetered Scattered Load	kWh	$ 0.0053	$ 0.0044
Sentinel Lighting	kW	$ 1.6785	$ 1.3751
Street Lighting	kW	$ 1.6701	$ 1.3469

APPENDIX H

2013 Incremental Capital Project Summary

Incremental Capital Workform for 2013 Filers

VERSION 1.0

Applicant Name	Festival Hydro Inc.
Application Type	IRM3
LDC Licence Number	ED-2002-0513
Applied for Effective Date	May 1, 2013
Stretch Factor Group	I
Stretch Factor Value	0.2%
Last COS Re-based Year	2010
Last COS OEB Application Number	EB-2009-0263
ICM Billing Determinants for Growth - Numerator	2010 Re-based Forecast
ICM Billing Determinants for Growth - Denominator	2011 Actual

Table of Contents

Rate Class and Re-Based Billing Determinants & Rates

Select the appropriate Rate Groups and Rate Classes from the drop-down menus in Columns C and D respectively. Following your selection, all appropriate input cells will be shaded green.

Last COS Re-based Year	**2010**
Last COS OEB Application Number	**EB-2009-0263**

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Tariff Service Charge D	Re-based Tariff Distribution Volumetric Rate kWh E	Re-based Tariff Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	17,115	141,132,375		14.75	0.0163	
RES	Residential - Hensall	Customer	kWh	413	4,143,109		11.21	0.0120	
GSLT50	General Service Less Than 50 kW	Customer	kWh	1,968	67,469,308		29.05	0.0145	
GSGT50	General Service 50 to 4,999 kW	Customer	kW	221	316,941,804	797,792	220.21		2.2579
LU	Large Use	Customer	kW	2	65,544,852	128,687	10,692.01		0.9922
USL	Unmetered Scattered Load	Connection	kWh	156	629,732		12.60	0.0125	
Sen	Sentinel Lighting	Connection	kW	83	234,690	679	1.41		7.3991
SL	Street Lighting	Connection	kW	5,915	3,904,130	11,255	0.77		3.4865
NA	Rate Class 9	NA	NA						
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

Removal of Rate Adders

Last COS Re-based Year **2010**

Last COS OEB Application Number **EB-2009-0263**

Rate Class	Re-based Tariff Service Charge A	Re-based Tariff Distribution Volumetric Rate kWh B	Re-based Tariff Distribution Volumetric Rate kW C	Service Charge Rate Adders D	Distribution Volumetric kWh Rate Adders E	Distribution Volumetric kW Rate Adders F
Residential	14.75	0.0163	0.0000	0.00	0.0000	0.0000
Residential - Hensall	11.21	0.0120	0.0000	0.00	0.0000	0.0000
General Service Less Than 50 kW	29.05	0.0145	0.0000	0.00	0.0000	0.0000
General Service 50 to 4,999 kW	220.21	0.0000	2.2579	0.00	0.0000	0.0000
Large Use	10,692.01	0.0000	0.9922	0.00	0.0000	0.0000
Unmetered Scattered Load	12.60	0.0125	0.0000	0.00	0.0000	0.0000
Sentinel Lighting	1.41	0.0000	7.3991	0.00	0.0000	0.0000
Street Lighting	0.77	0.0000	3.4865	0.00	0.0000	0.0000

Calculated Re-Based Revenue From Rates

Last COS Re-based Year	**2010**
Last COS OEB Application Number	**EB-2009-0263**

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Base Service Charge D	Re-based Base Distribution Volumetric Rate kWh E	Re-based Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I
Residential	17,115	141,132,375	0	14.75	0.0163	0.0000	3,029,355	2,300,458	0	5,329,813
Residential - Hensall	413	4,143,109	0	11.21	0.0120	0.0000	55,557	49,717	0	105,274
General Service Less Than 50 kW	1,968	67,469,308	0	29.05	0.0145	0.0000	686,045	978,305	0	1,664,350
General Service 50 to 4,999 kW	221	316,941,804	797,792	220.21	0.0000	2.2579	583,997	0	1,801,335	2,385,331
Large Use	2	65,544,852	128,687	10,692.01	0.0000	0.9922	256,608	0	127,683	384,291
Unmetered Scattered Load	156	629,732	0	12.60	0.0125	0.0000	23,587	7,872	0	31,459
Sentinel Lighting	83	234,690	679	1.41	0.0000	7.3991	1,404	0	5,024	6,428
Street Lighting	5,915	3,904,130	11,255	0.77	0.0000	3.4865	54,655	0	39,241	93,895
							4,691,208	3,336,352	1,973,282	10,000,842

Detailed Re-Based Revenue From Rates

Last COS Re-based Year | **2010**

Last COS OEB Application Number | **EB-2009-0263**

Applicants Rate Base		**Last Rate Re-based Amount**				
Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	73,469,244	A			
Add: CWIP Re-based Opening	$	3,357,000	B			
Re-based Capital Additions			C			
Re-based Capital Disposals			D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing			F			
Gross Fixed Assets - Re-based Closing	$	76,826,244	G			
Average Gross Fixed Assets				$	75,147,744	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	41,462,401	I			
Re-based Depreciation Expense	$	2,787,375	J			
Re-based Disposals			K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	44,249,776	M			
Average Accumulated Depreciation				$	42,856,089	N = (I + M) / 2
Average Net Fixed Assets				**$**	**32,291,656**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	52,239,484	P			
Working Capital Allowance Rate		15.0%	Q			
Working Capital Allowance				**$**	**7,835,923**	R = P * Q
Rate Base				**$**	**40,127,578**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	1,605,103	W = S * T
Deemed Long Term Debt %		56.00%	U	$	22,471,444	X = S * U
Deemed Equity %		40.00%	V	$	16,051,031	Y = S * V
Short Term Interest		2.07%	Z	$	33,226	AC = W * Z
Long Term Interest		5.68%	AA	$	1,276,862	AD = X * AA
Return on Equity		9.85%	AB	$	1,581,027	AE = Y * AB
Return on Rate Base				**$**	**2,891,114**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	3,930,487	AG			
Amortization	$	2,568,039	AH			
Ontario Capital Tax (F1.1 Z-Factor Tax Changes)	$	20,188	AI			
Grossed Up PILs (F1.1 Z-Factor Tax Changes)	$	848,366	AJ			
Low Voltage			AK			
Transformer Allowance	$	390,940	AL			
Property Tax	$	30,000	AM			
			AN			
			AO			
				$	**7,788,020**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	178,810	AQ			
Late Payment Charges	-$	133,335	AR			
Other Distribution Income	-$	204,175	AS			
Other Income and Deductions	-$	161,596	AT	**-$**	**677,916**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**10,001,218**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (B1.1 Re-based Revenue - Gen)				$	10,000,842	AW

Load Actual - Most Recent Year

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections	Billed kWh	Billed kW	Base Service Charge	Base Distribution Volumetric Rate kWh	Base Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class
			A	B	C	D	E	F	G = A * D * 12	H = B * E	I = C * F	J = G + H + I
Residential	Customer	kWh	17,243	137,110,454	0	$14.75	$0.0163	$0.0000	$3,052,011	$2,234,900	$0	$5,286,911
Residential - Hensall	Customer	kWh	410	3,814,545	0	$11.21	$0.0120	$0.0000	$55,153	$45,775	$0	$100,928
General Service Less Than 50 kW	Customer	kWh	2,000	63,567,429	0	$29.05	$0.0145	$0.0000	$697,200	$921,728	$0	$1,618,928
General Service 50 to 4,999 kW	Customer	kW	231	342,397,426	893,506	$220.21	$0.0000	$2.2579	$610,422	$0	$2,017,447	$2,627,869
Large Use	Customer	kW	1	30,589,560	59,443	$10,692.01	$0.0000	$0.9922	$128,304	$0	$58,979	$187,283
Unmetered Scattered Load	Connection	kWh	233	666,441	0	$12.60	$0.0125	$0.0000	$35,230	$8,331	$0	$43,560
Sentinel Lighting	Connection	kW	64	200,336	556	$1.41	$0.0000	$7.3991	$1,083	$0	$4,114	$5,197
Street Lighting	Connection	kW	6,240	4,206,123	11,209	$0.77	$0.0000	$3.4865	$57,658	$0	$39,080	$96,738
									$4,637,061	**$3,210,733**	**$2,119,621**	**$9,967,414**

This sheet is used to determine the applicants most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to be used to calculate the incremental capital rate riders.

Current Revenue from Rates

Rate Class	Fixed Metric	Vol Metric	Current Base Service Charge A	Current Base Distribution Volumetric Rate kWh B	Current Base Distribution Volumetric Rate kW C	Re-based Billed Customers or Connections D	Re-based Billed kWh E	Re-based Billed kW F	Current Base Service Charge Revenue G = A * D *12	Current Base Distribution Volumetric Rate kWh Revenue H = B * E	Current Base Distribution Volumetric Rate kW Revenue I = C * F	Total Current Base Revenue J = G + H + I	Service Charge % Total Revenue L = G / $K	Distribution Volumetric Rate % Total Revenue M = H / $K	Distribution Volumetric Rate % Total Revenue N = I / $K	Total % Revenue O = J / $K
Residential	Customer	kWh	14.75	0.0163		17,115	141,132,375	0	3,029,355	2,300,458	0	5,329,813	30.3%	23.0%	0.0%	53.3%
Residential - Hensall	Customer	kWh	11.21	0.0120		413	4,143,109	0	55,557	49,717	0	105,274	0.6%	0.5%	0.0%	1.1%
General Service Less Than 50 kW	Customer	kWh	29.05	0.0145		1,968	67,469,308	0	686,045	978,305	0	1,664,350	6.9%	9.8%	0.0%	16.6%
General Service 50 to 4,999 kW	Customer	kW	220.21		2.2579	221	316,941,804	797,792	583,997	0	1,801,335	2,385,331	5.8%	0.0%	18.0%	23.9%
Large Use	Customer	kW	10,692.01		0.9922	2	65,544,852	128,687	256,608	0	127,683	384,291	2.6%	0.0%	1.3%	3.8%
Unmetered Scattered Load	Connection	kWh	12.60	0.0125		156	629,732	0	23,587	7,872	0	31,459	0.2%	0.1%	0.0%	0.3%
Sentinel Lighting	Connection	kW	1.41		7.3991	83	234,690	679	1,404	0	5,024	6,428	0.0%	0.0%	0.1%	0.1%
Street Lighting	Connection	kW	0.77		3.4865	5,915	3,904,130	11,255	54,655	0	39,241	93,895	0.5%	0.0%	0.4%	0.9%
									4,691,208	3,336,352	1,973,282	10,000,842	46.9%	33.4%	19.7%	100.0%
												K				

Threshold Parameters

Price Cap Index

Price Escalator (GDP-IPI)	2.00%	
Less Productivity Factor	-0.72%	
Less Stretch Factor	-0.20%	
Price Cap Index		**1.08%**

Growth

ICM Billing Determinants for Growth - Numerator : 2010 Re-based Forecast	$ 9,967,414	A
ICM Billing Determinants for Growth - Denominator : 2011 Actual	$ 10,000,842	B
Growth	**-0.33%**	C = A / B

Threshold Test

Year		**2010**	
Price Cap Index		**1.08%**	**A**
Growth		**-0.33%**	**B**
Dead Band		**20%**	**C**
Average Net Fixed Assets			
Gross Fixed Assets Opening		$ 73,469,244	
Add: CWIP Opening		$ 3,357,000	
Capital Additions		$ -	
Capital Disposals		$ -	
Capital Retirements		$ -	
Deduct: CWIP Closing		$ -	
Gross Fixed Assets - Closing		$ 76,826,244	
Average Gross Fixed Assets		$ 75,147,744	
Accumulated Depreciation - Opening		$ 41,462,401	
Depreciation Expense		$ 2,787,375	D
Disposals		$ -	
Retirements		$ -	
Accumulated Depreciation - Closing		$ 44,249,776	
Average Accumulated Depreciation		$ 42,856,089	
Average Net Fixed Assets		$ 32,291,656	**E**
Working Capital Allowance			
Working Capital Allowance Base		$ 52,239,484	
Working Capital Allowance Rate		15%	
Working Capital Allowance		$ 7,835,923	**F**
Rate Base		**$ 40,127,578**	**G = E + F**
Depreciation	**D**	**$ 2,787,375**	**H**
Threshold Test		**130.68%**	**I = 1 + (G / H) * (B + A * (1 + B)) + C**
Threshold CAPEX		$ 3,642,654	**J = H *I**

Summary of Incremental Capital Projects (ICPs)

Number of ICPs
1

Project ID #	Incremental Capital Non-Discretionary Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Construction of 62 MVA Transformaton Station	7,777,903	188,104	660,552
		7,777,903	188,104	660,552

Incremental Capital Adjustment

Current Revenue Requirement				
Current Revenue Requirement - Total			$ 10,001,218	A

Return on Rate Base				
Incremental Capital CAPEX			$ 7,777,903	B
Depreciation Expense			$ 188,104	C
Incremental Capital CAPEX to be included in Rate Base			$ 7,589,799	D = B - C
Deemed ShortTerm Debt %	4.0%	E	$ 303,592	G = D * E
Deemed Long Term Debt %	56.0%	F	$ 4,250,287	H = D * F
Short Term Interest	2.07%	I	$ 6,284	K = G * I
Long Term Interest	5.68%	J	$ 241,508	L = H * J
Return on Rate Base - Interest			$ 247,792	M = K + L
Deemed Equity %	40.0%	N	$ 3,035,919	P = D * N
Return on Rate Base -Equity	9.85%	O	$ 299,038	Q = P * O
Return on Rate Base - Total			$ 546,830	R = M + Q

Amortization Expense				
Amortization Expense - Incremental		C	$ 188,104	S

Grossed up PIL's				
Regulatory Taxable Income		O	$ 299,038	T
Add Back Amortization Expense		S	$ 188,104	U
Deduct CCA			$ 660,552	V
Incremental Taxable Income			-$ 173,410	W = T + U - V
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26.5%	X		
PIL's Before Gross Up			-$ 45,954	Y = W * X
Incremental Grossed Up PIL's			-$ 62,522	Z = Y / (1 - X)

Ontario Capital Tax				
Incremental Capital CAPEX			$ 7,777,903	AA
Less : Available Capital Exemption (if any)			$ -	AB
Incremental Capital CAPEX subject to OCT			$ 7,777,903	AC = AA - AB
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	AD		
Incremental Ontario Capital Tax			$ -	AE = AC * AD

Incremental Revenue Requirement				
Return on Rate Base - Total		Q	$ 546,830	AF
Amortization Expense - Total		S	$ 188,104	AG
Incremental Grossed Up PIL's		Z	-$ 62,522	AH
Incremental Ontario Capital Tax		AE	$ -	AI
Incremental Revenue Requirement			$ 672,412	AJ = AF + AG + AH + AI

Calculation of Incremental Capital Rate Rider - Option A Fixed and Variable

Rate Class	Service Charge % Revenue A	Distribution Volumetric Rate % Revenue kWh B	Distribution Volumetric Rate % Revenue kW C	Service Charge Revenue D = $N * A	Distribution Volumetric Rate Revenue kWh E = $N * B	Distribution Volumetric Rate Revenue kW F = $N * C	Total Revenue by Rate Class G = D + E + F	Billed Customers or Connections H	Billed kWh I	Billed kW J	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kW Rate Rider M = F / J
Residential	30.3%	23.0%	0.0%	$ 203,680.39	$ 154,672.57	$ -	$ 358,352.96	17,115	141,132,375	0	$0.991725	$0.001096	
Residential - Hensall	0.6%	0.5%	0.0%	$ 3,735.39	$ 3,342.77	$ -	$ 7,078.16	413	4,143,109	0	$0.753711	$0.000807	
General Service Less Than 50 kW	6.9%	9.8%	0.0%	$ 46,126.61	$ 65,776.89	$ -	$ 111,903.49	1,968	67,469,308	0	$1.953193	$0.000975	
General Service 50 to 4,999 kW	5.8%	0.0%	18.0%	$ 39,265.36	$ -	$ 121,113.74	$ 160,379.11	221	316,941,804	797,792	$14.805943	$0.000000	$0.151811
Large Use	2.6%	0.0%	1.3%	$ 17,253.20	$ -	$ 8,584.85	$ 25,838.05	2	65,544,852	128,687	$718.883320	$0.000000	$0.066711
Unmetered Scattered Load	0.2%	0.1%	0.0%	$ 1,585.90	$ 529.25	$ -	$ 2,115.15	156	629,732	0	$0.847168	$0.000840	
Sentinel Lighting	0.0%	0.0%	0.1%	$ 94.42	$ -	$ 337.79	$ 432.21	83	234,690	679	$0.094802	$0.000000	$0.497483
Street Lighting	0.5%	0.0%	0.4%	$ 3,674.73	$ -	$ 2,638.36	$ 6,313.09	5,915	3,904,130	11,255	$0.051771	$0.000000	$0.234417
				$ 315,416.01	$ 224,321.48	$ 132,674.75	$ 672,412.24						
							-						

Enter the above rate riders onto "Sheet 11. Proposed Rates" in the 2013 OEB IRM3 Rate Generator as a "Rate Rider for Incremental Capital"

Calculation of Incremental Capital Rate Rider - Option B Variable

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Incremental Capital $ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential	$5,329,813	53.29%	$358,353	141,132,375	0	$0.0025	
Residential - Hensall	$105,274	1.05%	$7,078	4,143,109	0	$0.0017	
General Service Less Than 50 kW	$1,664,350	16.64%	$111,903	67,469,308	0	$0.0017	
General Service 50 to 4,999 kW	$2,385,331	23.85%	$160,379	316,941,804	797,792		$0.2010
Large Use	$384,291	3.84%	$25,838	65,544,852	128,687		$0.2008
Unmetered Scattered Load	$31,459	0.31%	$2,115	629,732	0	$0.0034	
Sentinel Lighting	$6,428	0.06%	$432	234,690	679		$0.6365
Street Lighting	$93,895	0.94%	$6,313	3,904,130	11,255		$0.5609
	$10,000,842	100.00%	$672,412				
	H		I				

Enter the above rate riders onto "Sheet
11. Proposed Rates" in the 2013 OEB IRM3 Rate Generator as a "Rate Rider for Incremental Capital"

APPENDIX G

2013 Incremental Capital Workform

Incremental Capital Project Summary for 2013 Filers

Version 1.0

Applicant Name:	Festival Hydro Inc.
Name:	Debbie Reece
Title:	Chief Financial Officer
Phone Number:	519-271-4703 x.268
Email Address:	dreece@festivalhydro.com

Using the pull-down menu below, please identify what year of the IRM cycle you are in.

3rd year of IRM cycle

Name or General Description of Project

Construction of a 62 MVA Transformation Station

Details of Project

62 MVA Transformation Station construction. See Managers Summary for details.

	Asset Component	Capital Cost	Depreciation Rate	CCA Class	CCA Rate
1	TS - Bushings, electronics, tap changers, vault lids	828,652	4%	47	8%
2	TS - Switchgear, cable, transformers, breakers	2,255,262	3%	47	8%
3	TS - HV switch, structure, bus, foundations, ducts, vaults	4,277,693	2%	47	8%
4	TS - DC Systems and Computers	130,224	10%	50	55%
5	Land & costs to prepare land	439,726			

	2013	2014	2015	2016
Closing Net Fixed Asset	7,743,453	7,555,349	7,367,245	7,179,141
Amortization Expense	188,104	188,104	188,104	188,104
CCA	660,552	574,045	512,973	465,118

Fixed Asset Amortization and UCC 1

Name or General Description of Project

Construction of a 62 MVA Transformation Station

Asset Component

TS - Bushings, electronics, tap changers, vault lids

Average Net Fixed Assets

Net Fixed Assets

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment		$ -	$ 828,652	$ 828,652	$ 828,652	$ 828,652
Capital Investment		$ 828,652	$ -	$ -	$ -	$ -
Closing Capital Investment		$ 828,652	$ 828,652	$ 828,652	$ 828,652	$ 828,652
Opening Accumulated Amortization		$ -	$ 33,146	$ 66,292	$ 99,438	$ 132,584
Amortization	4%	$ 33,146	$ 33,146	$ 33,146	$ 33,146	$ 33,146
Closing Accumulated Amortization		$ 33,146	$ 66,292	$ 99,438	$ 132,584	$ 165,730
Opening Net Fixed Assets		$ -	$ 795,506	$ 762,360	$ 729,214	$ 696,068
Closing Net Fixed Assets		$ 795,506	$ 762,360	$ 729,214	$ 696,068	$ 662,922
Average Net Fixed Assets		$ 397,753	$ 778,933	$ 745,787	$ 712,641	$ 679,495

For PILs Calculation

UCC

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC		$ -	$ 762,360	$ 701,371	$ 645,261	$ 593,640
Capital Additions		$ 828,652	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 828,652	$ 762,360	$ 701,371	$ 645,261	$ 593,640
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ 828,652	$ 762,360	$ 701,371	$ 645,261	$ 593,640
CCA Rate Class	47					
CCA Rate	8%					
CCA		$ 66,292	$ 60,989	$ 56,110	$ 51,621	$ 47,491
Closing UCC		$ 762,360	$ 701,371	$ 645,261	$ 593,640	$ 546,149

Fixed Asset Amortization and UCC 1

Name or General Description of Project

Construction of a 62 MVA Transformation Station

Asset Component

TS - Switchgear, cable, transformers, breakers

Average Net Fixed Assets

Net Fixed Assets

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment		$ -	########	########	########	########
Capital Investment		########	$ -	$ -	$ -	$ -
Closing Capital Investment		########	########	########	########	########
Opening Accumulated Amortization		$ -	$ 56,382	$ 112,763	$ 169,145	$ 225,526
Amortization	3%	$ 56,382	$ 56,382	$ 56,382	$ 56,382	$ 56,382
Closing Accumulated Amortization		$ 56,382	$ 112,763	$ 169,145	$ 225,526	$ 281,908
Opening Net Fixed Assets		$ -	########	########	########	########
Closing Net Fixed Assets		########	########	########	########	########
Average Net Fixed Assets		########	########	########	########	########

For PILs Calculation

UCC

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC		$ -	########	########	########	########
Capital Additions		########	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		########	########	########	########	########
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		########	########	########	########	########
CCA Rate Class	47					
CCA Rate	8%					
CCA		$ 180,421	$ 165,987	$ 152,708	$ 140,492	$ 129,252
Closing UCC		########	########	########	########	########

Fixed Asset Amortization and UCC 1

Name or General Description of Project

Construction of a 62 MVA Transformation Station

Asset Component

TS - HV switch, structure, bus, foundations, ducts, vaults

Average Net Fixed Assets

Net Fixed Assets

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment		$ -	########	########	########	########
Capital Investment		########	$ -	$ -	$ -	$ -
Closing Capital Investment		########	########	########	########	########
Opening Accumulated Amortization		$ -	$ 85,554	$ 171,108	$ 256,662	$ 342,215
Amortization	2%	$ 85,554	$ 85,554	$ 85,554	$ 85,554	$ 85,554
Closing Accumulated Amortization		$ 85,554	$ 171,108	$ 256,662	$ 342,215	$ 427,769
Opening Net Fixed Assets		$ -	########	########	########	########
Closing Net Fixed Assets		########	########	########	########	########
Average Net Fixed Assets		########	########	########	########	########

For PILs Calculation

UCC

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC		$ -	########	########	########	########
Capital Additions		########	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		########	########	########	########	########
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		########	########	########	########	########
CCA Rate Class	47					
CCA Rate	8%					
CCA		$ 342,215	$ 314,838	$ 289,651	$ 266,479	$ 245,161
Closing UCC		########	########	########	########	########

Fixed Asset Amortization and UCC 1

Name or General Description of Project

Construction of a 62 MVA Transformation Station

Asset Component

TS - DC Systems and Computers

Average Net Fixed Assets

Net Fixed Assets

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment		$ -	$ 130,224	$ 130,224	$ 130,224	$ 130,224
Capital Investment		$ 130,224	$ -	$ -	$ -	$ -
Closing Capital Investment		$ 130,224	$ 130,224	$ 130,224	$ 130,224	$ 130,224
Opening Accumulated Amortization		$ -	$ 13,022	$ 26,045	$ 39,067	$ 52,090
Amortization	10%	$ 13,022	$ 13,022	$ 13,022	$ 13,022	$ 13,022
Closing Accumulated Amortization		$ 13,022	$ 26,045	$ 39,067	$ 52,090	$ 65,112
Opening Net Fixed Assets		$ -	$ 117,202	$ 104,179	$ 91,157	$ 78,134
Closing Net Fixed Assets		$ 117,202	$ 104,179	$ 91,157	$ 78,134	$ 65,112
Average Net Fixed Assets		$ 58,601	$ 110,690	$ 97,668	$ 84,646	$ 71,623

For PILs Calculation

UCC

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC		$ -	$ 58,601	$ 26,370	$ 11,867	$ 5,340
Capital Additions		$ 130,224	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 130,224	$ 58,601	$ 26,370	$ 11,867	$ 5,340
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ 130,224	$ 58,601	$ 26,370	$ 11,867	$ 5,340
CCA Rate Class	50					
CCA Rate	55%					
CCA		$ 71,623	$ 32,230	$ 14,504	$ 6,527	$ 2,937
Closing UCC		$ 58,601	$ 26,370	$ 11,867	$ 5,340	$ 2,403

Fixed Asset Amortization and UCC 1

Name or General Description of Project

Construction of a 62 MVA Transformation Station

Asset Component

Land & costs to prepare land

Average Net Fixed Assets

Net Fixed Assets

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening Capital Investment		$ -	$ 439,726	$ 439,726	$ 439,726	$ 439,726
Capital Investment		$ 439,726	$ -	$ -	$ -	$ -
Closing Capital Investment		$ 439,726	$ 439,726	$ 439,726	$ 439,726	$ 439,726
Opening Accumulated Amortization		$ -	$ -	$ -	$ -	$ -
Amortization	0%	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ 439,726	$ 439,726	$ 439,726	$ 439,726
Closing Net Fixed Assets		$ 439,726	$ 439,726	$ 439,726	$ 439,726	$ 439,726
Average Net Fixed Assets		$ 219,863	$ 439,726	$ 439,726	$ 439,726	$ 439,726

For PILs Calculation

UCC

		2013 Forecasted	2014 Forecasted	2015 Forecasted	2016 Forecasted	2017 Forecasted
Opening UCC		$ -	$ 439,726	$ 439,726	$ 439,726	$ 439,726
Capital Additions		$ 439,726	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 439,726	$ 439,726	$ 439,726	$ 439,726	$ 439,726
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ 439,726	$ 439,726	$ 439,726	$ 439,726	$ 439,726
CCA Rate Class	0					
CCA Rate	0%					
CCA		$ -	$ -	$ -	$ -	$ -
Closing UCC		$ 439,726	$ 439,726	$ 439,726	$ 439,726	$ 439,726

APPENDIX I

2013 Incremental Capital Supplementary Documents

1. 2013 Capital Details

Draft Capital Budget for 2013

The 2013 Budget for typical capital expenditures is $3,489,000.

Of the typical capital expenditures of $3.48 million, $2.4 million has been allocated to the replacement of depreciated plant, vehicles and equipment. Approximately $0.6 million has been allocated for growth related projects (new/upgraded services, customer driven work), which is similar to previous years. A total of $490,000 has been allocated for implementing new technology to improve reliability and power quality.

The following explanations and attached tables will provide greater detail of the specific projects.

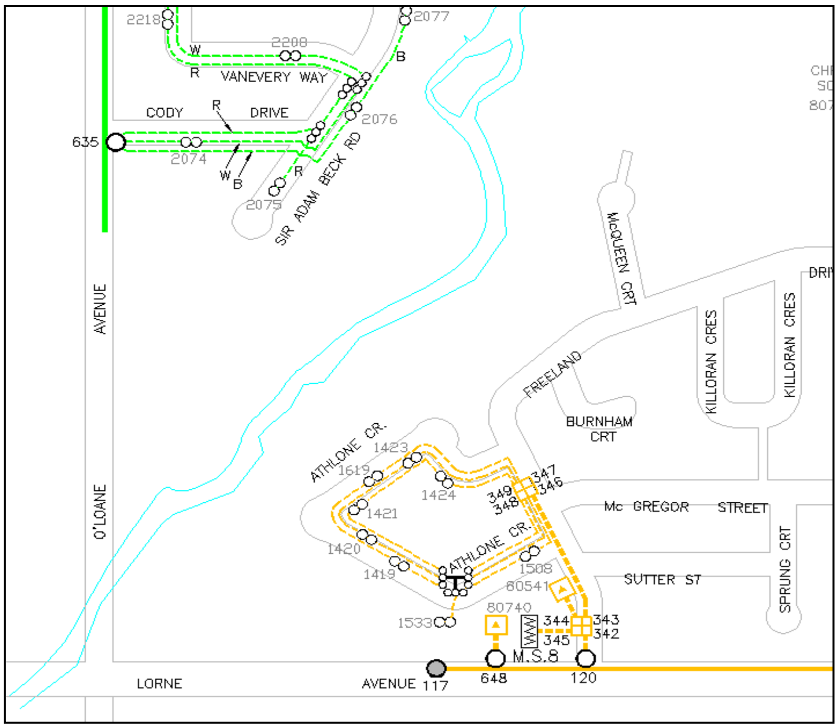
Replacement and Reliability Projects

These are projects initiated by the engineering department, to address system problems, reduce losses, improve safety, and decrease outages. They include projects such as voltage conversion, line rebuilds, and insulator replacements.

Stratford

Stratford – Lorne and O'Loane Ave – 3 Phase Circuit Tie

This project is related to the new Stratford TS build, and it will create a loop-feed for the 68M5 feeder by connecting Lorne and O'Loane Ave. This overhead/underground feeder tie will allow the 68M5 feeder length to be reduced in half (from 5000 to 2500 customers) and will also allow power to be re-routed in the event of an outage which will improve reliability to the area.



The scope of this project is to extend the overhead line on Lorne Ave to O'Loane Ave (about 1000m). Then the line will dip underground and egress to the current line on O'Loane Ave. Poles will be framed for a single 27.6 kV circuit and the underground portion will be built with 3 phase 500 MCM cable.

The cost of this project is estimated at $298,500.

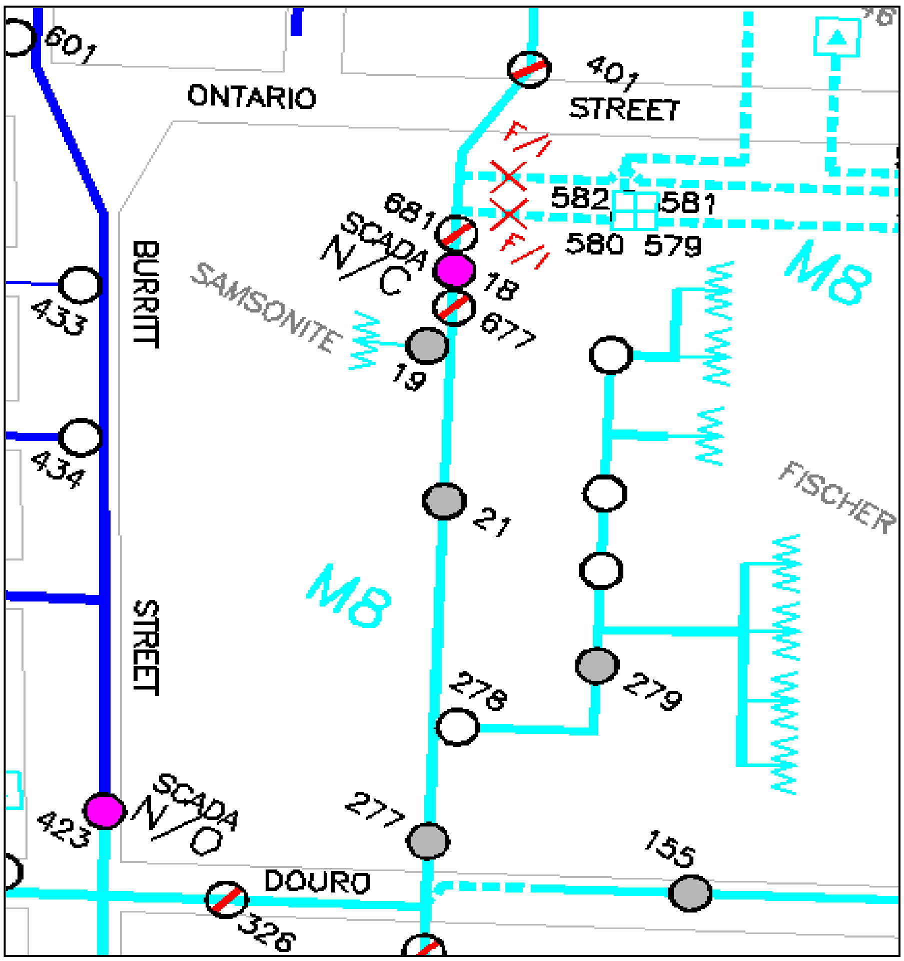
If this project is not completed, this area will continue to be on a radial supply and at risk for extended outages. This expansion also allows for load to be transferred from existing TS to the new TS.

This project is expected to be started on September 1, 2013 and be in service by December 30, 2013,

Stratford – M8 Feeder Rebuild – Ontario to Douro

This project will replace aging infrastructure that has been identified as a potential risk for failure in the near future.

The scope of this project is an overhead line which runs parallel to Burritt St from Ontario to Douro Rd (about 700 m long) on the M8 feeder that has reached end of life. Poles, crossarms, insulators, and transformers are over 40 years old and in relatively poor condition.



The cost of this project is estimated at $151,600

If this project is not completed, the Stratford M8 feeder will be at risk of future outages due to equipment failure. The M8 feeder is one of the better performing feeders for the past several years; this project will maintain this level of reliability by preventing future outages due to failed equipment.

This project is expected to start on March 1, 2013 and be in service by October 31, 2013

Stratford – Reinsulate Poles – 68M2 Feeder Phase 2

This project is year 2 of a two year project to upgrade the insulators on the Stratford M2 feeder, which has been identified as one of the worst performing feeder for several years. Analysis of the outage causes indicates that animal contacts are the major cause of outages, and further inspection of the feeder suggests the clearance from primary conductor to pole is insufficient to prevent squirrel contacts.

This scope of this project is to install fiberglass extension brackets on the existing insulators and to replace any metallic fasteners as a means of increasing clearances on the poles. It is anticipated that when this project is complete in 2013, the number of squirrel contacts for the M2 feeder will be reduced from an average of 10 per year to 5 or fewer. The area where this project takes place will affect approximately 900 customers over the two year period.

The cost of this project is estimated at $250,000.

If this project is not completed, the Stratford M2 feeder will be at risk of future outages due to animal contacts. The M2 feeder has been one of the worst performing feeders for the past several years, and this project will prevent future outages due to animal contacts. Other alternatives have been investigated (such as various types of “squirrel guards”) but have not been as effective as the use of these fiberglass extension brackets.

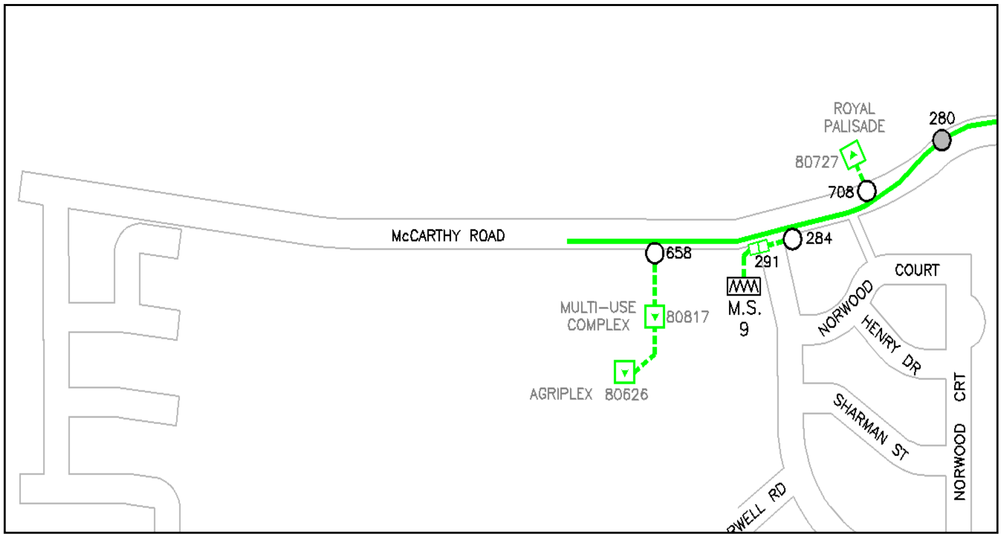
This project is expected to start on March 1, 2013 and be in service by December 31, 2013.

Stratford – McCarthy Rd Extension – 68M5 Feeder

This project will extend the current 68M5 feeder to Forman Ave. This extension is being constructed for 2 main reasons 1) Connect a new residential subdivision under development which includes some areas for commercial/light industrial development and 2) We will tie this extension into the M5 feeder to improve reliability and increase operating flexibility.

The scope of this project is to extend the 68M5 feeder from McCarthy to Forman

The cost of this project is estimated at $125,500

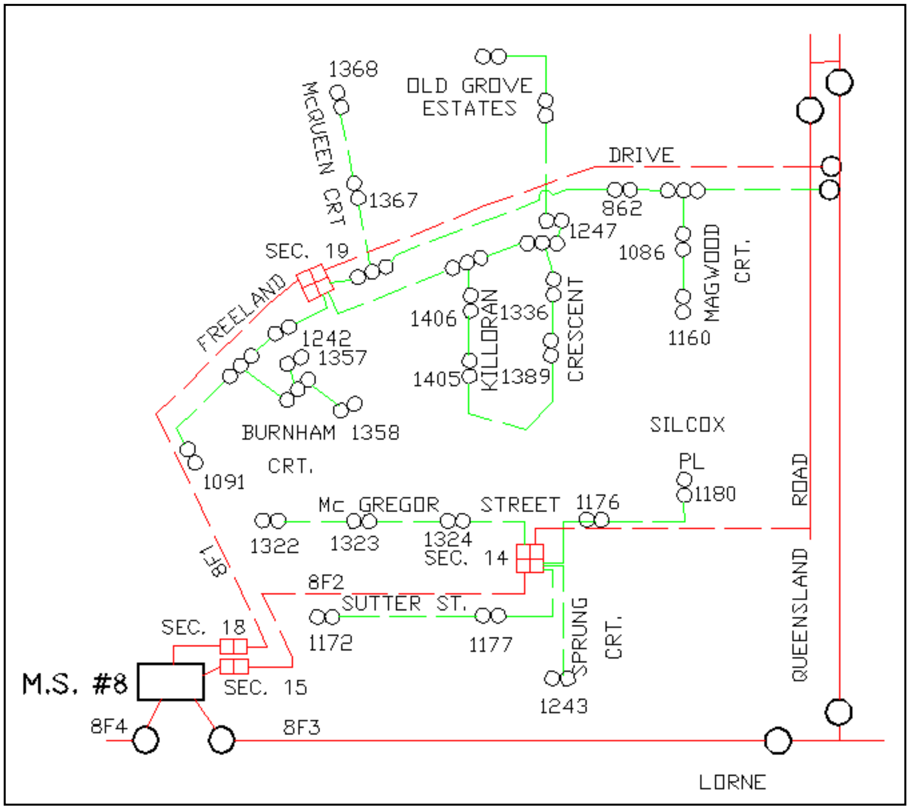


If this project is not completed, new customers will not be able to locate to in this subdivision due to the lack of servicing. Also, the 68M5 circuit is a long feeder which snakes around much of Stratford, the installation of this tie will help in circuit reliability.

Stratford – M.S #8 Ph-2 Conversion

This municipal substation was built in 1979 to supply the local area with 4 kV distribution. The station is approaching end of life, and the majority of the 4 kV distribution system is also nearing end of life. Therefore, rather than replace both the station and distribution with 4 kV equipment, it was decided to convert the area to 27.6 kV to eliminate the need for the station and reduce system losses. This project will span several USofA accounts, and will be completed over a five year period from 2010 to 2014. As each street is converted to 27.6 kV, it will be immediately put into service.

The scope of this year's portion of the project is to complete the conversion on Freeland, Sutter, McGregor, Sprung, Silcox, Magwood, Burnham and Killoran st. After these streets are converted the last step will be to decommission the station in 2014.



The purpose of this project is to replace distribution infrastructure that is at end of life, convert the 4 kV load to 27.6 kV supply, and allow the Station to be decommissioned in 2014.

The cost of this portion of the project is estimated at $188,000.

If this project is not completed, the 4 kV equipment (transformers and cables) will need to be replaced with 4 kV equipment at a cost of $81,000 and the Station will need to be replaced in approximately 2014 at a cost of approximately $3,000,000. The alternative of converting this area to overhead distribution was not investigated as the City will not allow new overhead distribution in residential subdivisions.

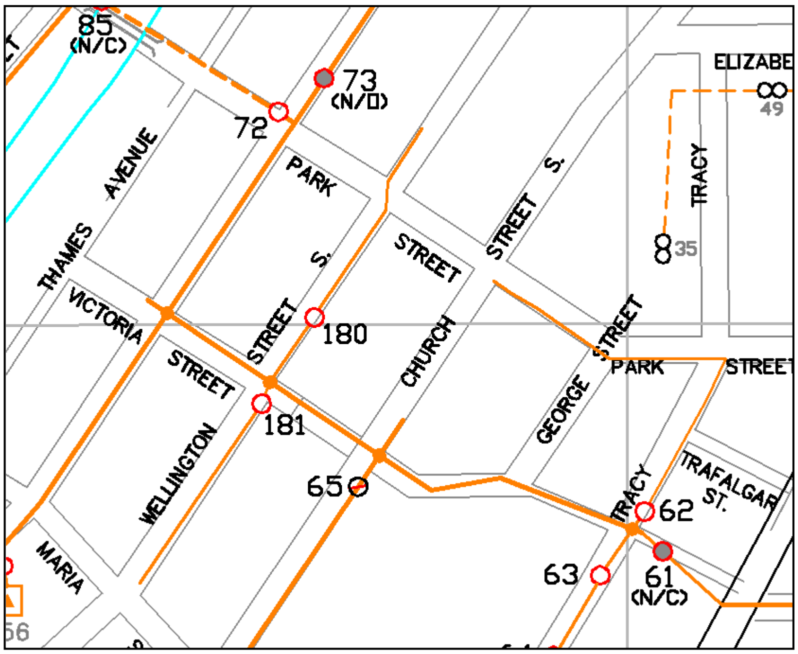
This project is expected to be started on March 1, 2013 and be in service by October 30, 2013.

St. Marys

St Marys – Victoria St – M4 Rebuild

This project will replace aging infrastructure that has been identified as a potential risk for failure in the near future.

The scope of this project is an overhead line on Victoria St from the railroad tracks to Wellington St (about 400 m long) on the M4 feeder that has reached end of life. Poles, crossarms, insulators, conductor and transformers are over 40 years old and in relatively poor condition.



The cost of this project is estimated at $76,000

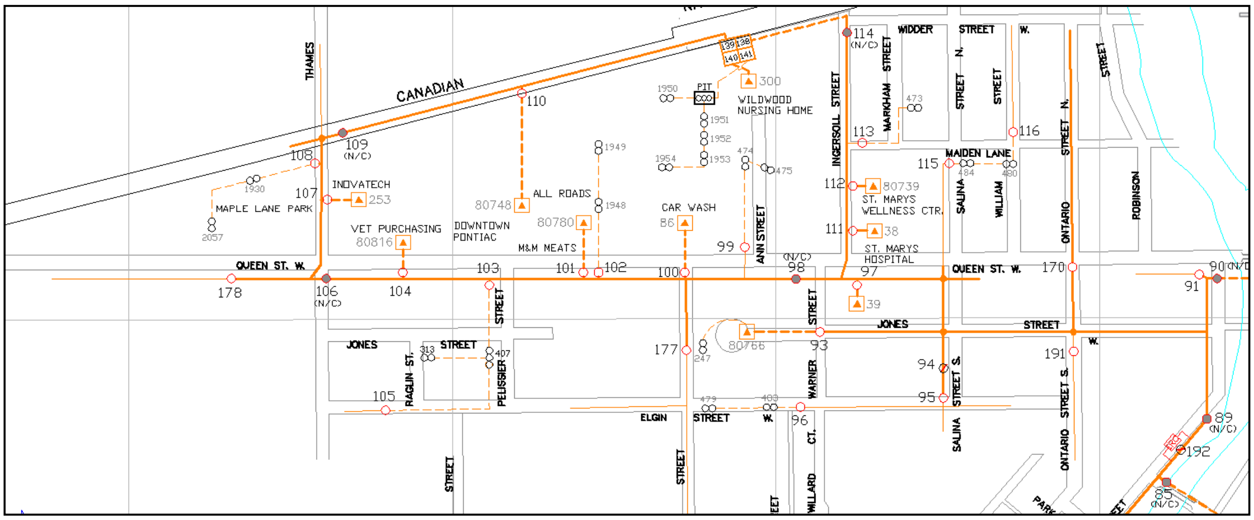
If this project is not completed, the St Marys M4 feeder will be at risk of future outages due to equipment failure. The M4 feeder has been one of the worst performing feeders for the past several years, and this project will prevent future outages due to failed equipment.

This project is expected to start on March 1, 2013 and be in service by October 31, 2013.

St Marys – Queen St – M4 Rebuild

This project will replace aging infrastructure that has been identified as a potential risk for failure in the near future.

The scope of this project is an overhead line on Queen St from the the river to the west boundary. (about 1800 m long) on the M4 feeder that has reached end of life. Poles, crossarms, insulators, and transformers are over 40 years old and in relatively poor condition. The conductor will be reused



The cost of this project is estimated at $280,000

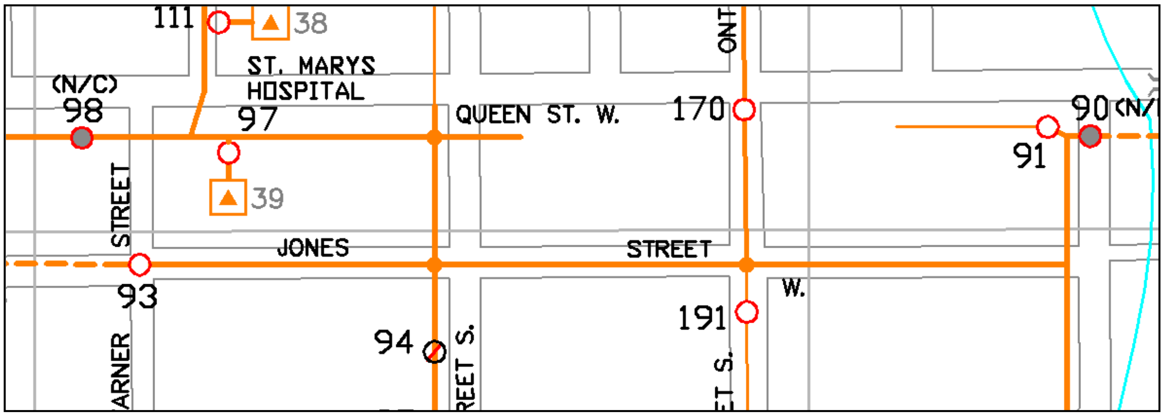
If this project is not completed, the St Marys M4 feeder will be at risk of future outages due to equipment failure. The M4 feeder has been one of the worst performing feeders for the past several years, and this project will prevent future outages due to failed equipment.

This project is expected to start on May 1, 2013 and be in service by November 30, 2013.

St Marys – Jones St. West – M4 Rebuild

This project will replace aging infrastructure that has been identified as a potential risk for failure in the near future.

The scope of this project is an overhead line on Jones St. from Thomas to Warner. (about 600m long) on the M4 feeder that has reached end of life. Poles, crossarms, insulators, conductors and transformers are over 40 years old and in relatively poor condition.



The cost of this project is estimated at $202,000

If this project is not completed, the St Marys M4 feeder will be at risk of future outages due to equipment failure. The M4 feeder has been one of the worst performing feeders for the past several years, and this project will prevent future outages due to failed equipment.

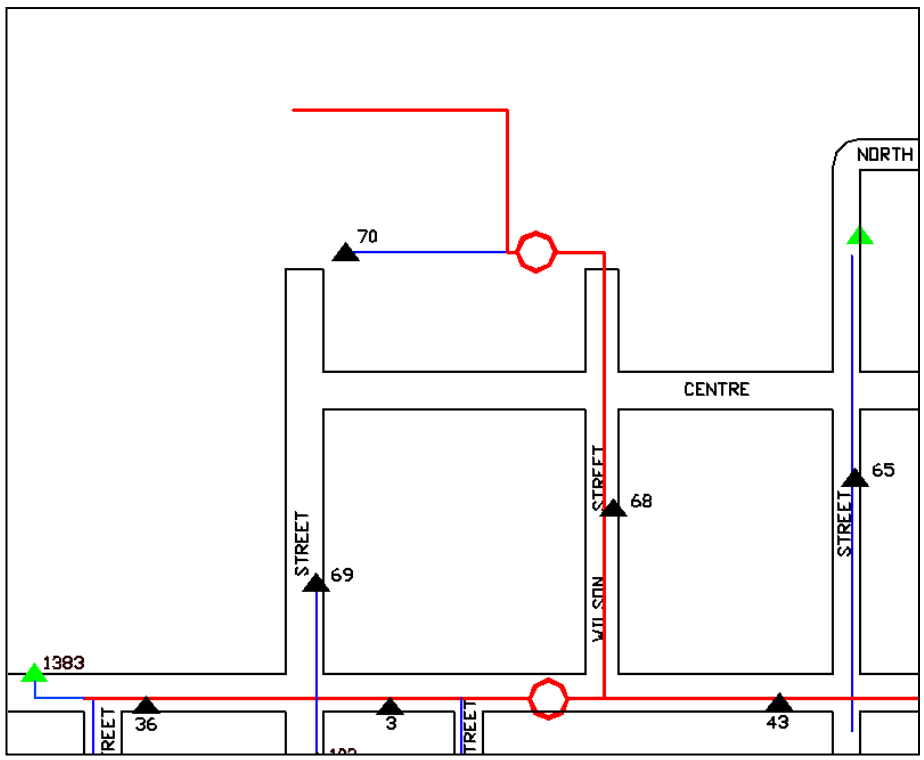
This project is expected to start on October 1, 2013 and be in service by Decemeber 31, 2013.

Seaforth

Seaforth – Centre Street – Rear Yard Conversion

This project will convert existing backyard primary infrastructure to front yard secondary connections.

The scope of this project is primary infrastructure between Wilson and Ann st.



This project is being undertaken for safety purposes. Primary conductor in backyards can be hazardous if homeowners become complacent in working around the infrastructure. By converting this primary backward construction to secondary right away we reduce the risk of contact by homeowners.

The cost of this project is estimated at $38,500

If this project is not completed, there is a greater risk of primary contact and any system repairs would take longer to complete backyards are harder and less efficient to access they right of way construction.

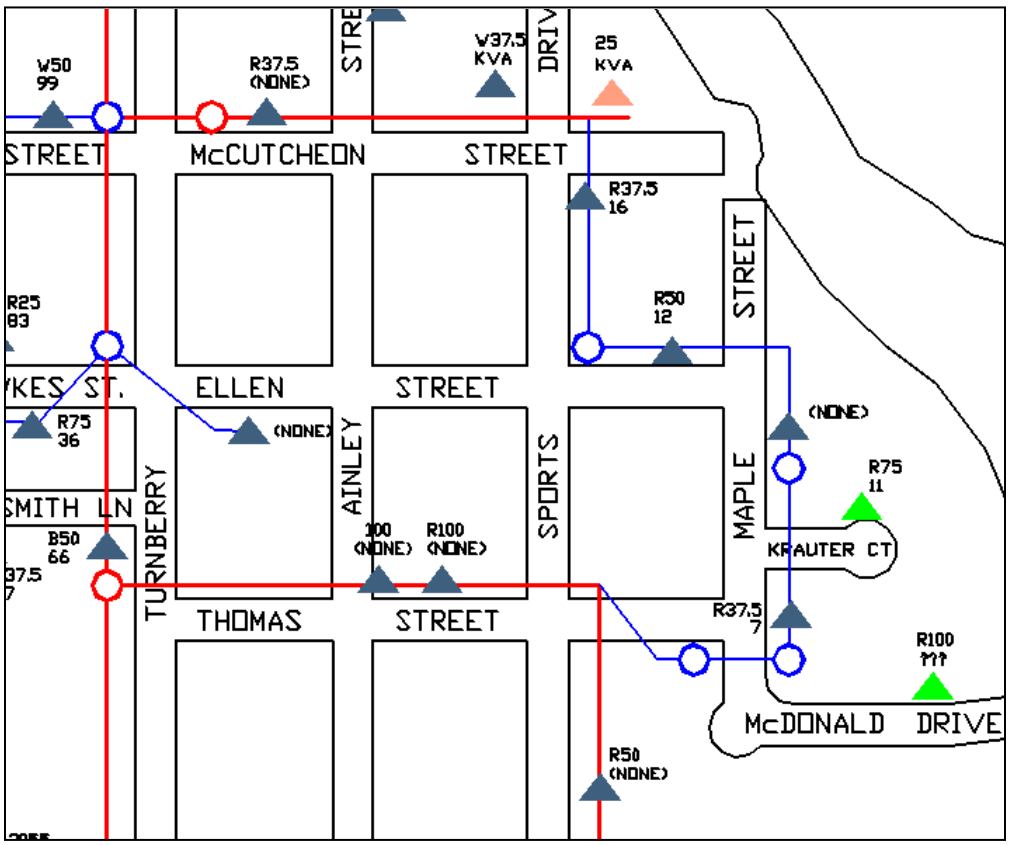
This project is expected to start on May 1, 2013 and be in service by August 31, 2013.

Brussels

Brussels – Sports Drive, Thomas and Maple – Rebuild

This project will replace aging infrastructure that has been identified as a potential risk for failure in the near future.

The scope of this project is an overhead line on Thomas, Sports Dr and Maple St. (about 800 m long) that has reached end of life. Poles, crossarms, insulators, conductor and transformers are over 40 years old and in relatively poor condition.



The cost of this project is estimated at $112,900

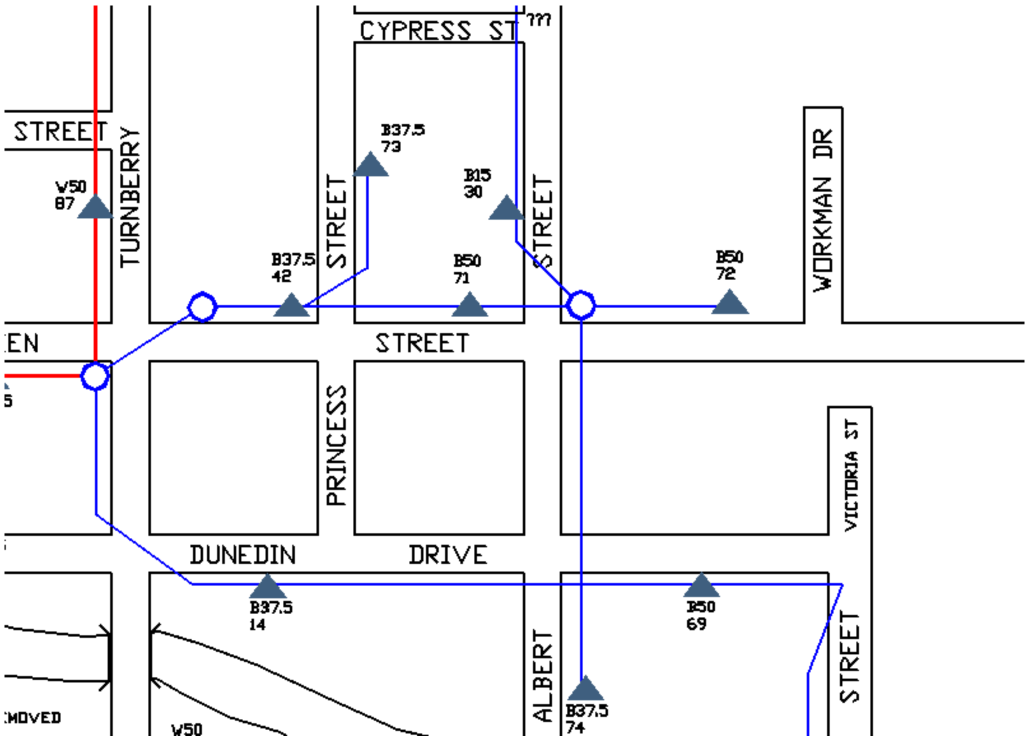
If this project is not completed, the Brussels feeder will be at risk of future outages due to equipment failure. This project will prevent future outages due to failed equipment.

This project is expected to start on August 1, 2013 and be in service by September 30, 2013.

Brussels – Queen St and Dunedin Dr – Rebuild

This project will replace aging infrastructure that has been identified as a potential risk for failure in the near future.

The scope of this project is an overhead line on Queen Street from Turnberry to city limits and all of Dunedin Dr (about 1000 m long) that has reached end of life. Poles, crossarms, insulators, conductor and transformers are over 40 years old and in relatively poor condition.



The cost of this project is estimated at $150,000

If this project is not completed, the Brussels feeder will be at risk of future outages due to equipment failure. This project will prevent future outages due to failed equipment.

This project is expected to start on October 1, 2013 and be in service by Decemeber 31, 2013.

Growth Related Work

New and upgraded residential and commercial developments represent approximately $610,000 of the budget. This work is completely customer driven, but we don't see the growth rates of our communities changing much between 2012 and 2013. Therefore we have decided to keep the capital estimate virtually unchanged from 2012.

New Technology

A pilot project will be continued to install 2 dead-front padmounted switch-gear. In the past we have had reliability issues associated with the live front PMH gear (ie foreign interference, tracking etc) This pilot will focus on units with a history of failures or ones which have registered on our thermal studies. We will rank the switch gear and change the 2 worst units. We will then evaluate how the dead-front units perform and develop a long term switch-gear plan.

The cost of this project is estimated at $90,000

Transformers

Additional transformers needed due to load growth, replacements, conversions, and new developments are expected to cost $225,000. This amount is comparable to 2012. Note that this budget amount is for the transformer purchases only; it does not include the labour to install them which is accounted for in the project cost.

Metering

Capital costs associated with meter replacements and upgrades will be $51,000. This value is in line with previous years.

Fleet

Through changes made to fleet maintenance and the Seaforth service center it appears that we will only need to purchase 1 new pickup truck for 2013. This vehicle is estimated to cost $32,000

Computer Equipment

The expected costs to upgrade computer and office equipment will be $120,000. This includes the on-going replacements and upgrading of computers and software.

Distribution Automation

Additional SCADA switches will be purchased to tie feeders from the two Stratford Stations together. The purpose of these switches are to automatically reestablish power to area which are affected by breaker lockouts ,but where no fault is present. These installations will help reliability and propagate the smart grid. We will also be required to upgrade the current SCADA switches firmware and enhance the current SCADA system. The estimated cost of these upgrades is $400,000.

Tools

Tools and miscellaneous equipment costs will be $20,000. Most of the purchases are for expected replacements of existing tools and equipment as they reach end of life.

Lands and Buildings

The Lands and Buildings budget includes replacement of a couple HVAC units (service center and administration building), further upgrades to the security system (cameras and key cards for restricted areas), and minor office renovations. The total cost for these upgrades is estimated at $68,000.

FESTIVAL HYDRO

08/22/2012

2013 CAPITAL BUDGET - DRAFT #1

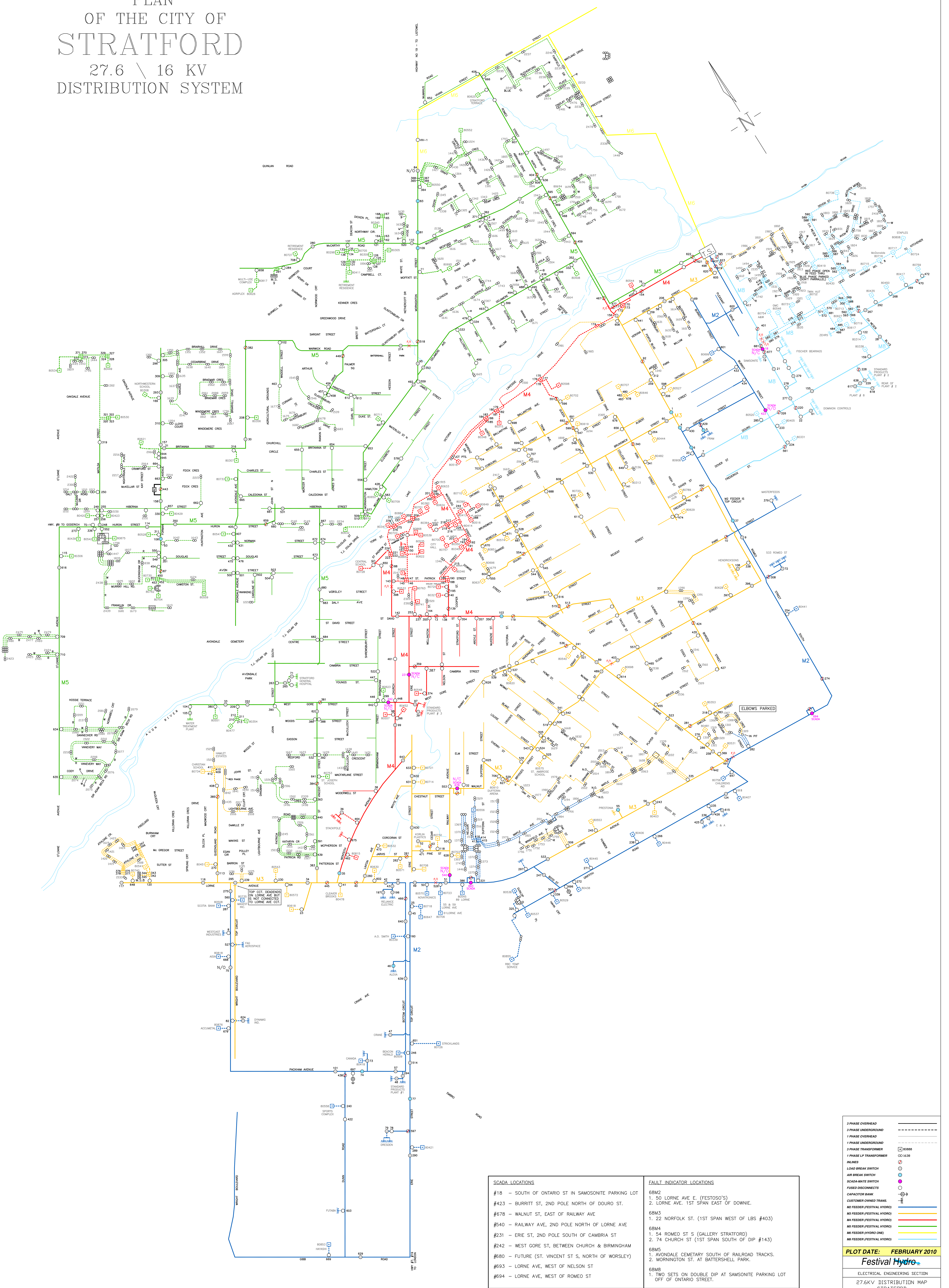
				2013 Budget	Projects by Area		
					Stratford	St. Marys	Seaforth
					$1,303,600	**$558,000**	**$301,400**
	Overhead Distribution Projects			**$1,700,500**			
	S	Lorne Ave & O'Loane Ave Tie		$124,500	$124,500		
	S	M8 Feeder - Ontario to Douro		$151,600	$151,600		
	S	McCarthy Road West Extention		$125,500	$125,500		
	S	Reinsulate 68M2		$250,000	$250,000		
	SM	Victoria Street M4 Rebuild (RRX to Wellington)		$76,000		$76,000	
	SM	Jones St. West Rebuild (Thomas to Warner)		$202,000		$202,000	
	SM	Queen St. Rebuild		$280,000		$280,000	
	SF	Centre Street rear yard conversion (Willson to Ann)		$28,000			$28,000
	B	Sports Drive, Thomas & Maple		$112,900			$112,900
	B	Queen St, Dunedin		$150,000			$150,000
	S	Scada Switches		$200,000	$200,000		
	Underground Distribution Projects			**$462,500**			
	S	O'Loane (feeder tie) from Lorne Ave. (includes river crossing)		$174,000	$174,000		
	S	M.S. #8 Ph2-Conversion (Freeland,Sutter,McGregor,Sprung,Silcox,Magwood,Burnham & Killoran)		$188,000	$188,000		
	S	Switchgear - 2 Deadfront Units		$90,000	$90,000		
	SF	Centre Street reard yard conversion (directional drill)		$10,500			$10,500
	Distribution Transformers - Purchases only - no labour			**$225,000**			
		Capital Additions -Customer driven		**$460,000**			
	New/Upgraded Services			**$150,000**			
	Distribution Meters			**$51,000**			
		Residential/Commercial/Industrial Meters		$51,000			
	Scada System			**$200,000**			
		Scada Enhancements		$200,000			
	Tools & Misc. Equipment			**$20,000**			
		Tools - Operations		$15,000			
		Misc Purchases		$5,000			
			SUB TOTAL	**$3,269,000**			
	Lands and Buildings			**$68,000**			
	Administration Building			$43,000			
	Service Centre			$25,000			
	Vehicles and Trailers			**$32,000**			
		New Pickup Truck		$32,000			
	Computer Equipment			**$120,000**			
		Softwre Purchases		$88,000			
		Hardware Purchases		$32,000			
			TOTAL	**$3,489,000**	$1,303,600	$558,000	$301,400

TOTAL **$3,489,000**

2. Stratford Distribution Map

PLAN OF THE CITY OF STRATFORD

27.6 \ 16 KV DISTRIBUTION SYSTEM



SCADA LOCATIONS
#18 – SOUTH OF ONTARIO ST IN SAMOSONITE PARKING LOT
#423 – BURRITT ST, 2ND POLE NORTH OF DOURO ST.
#678 – WALNUT ST, EAST OF RAILWAY AVE
#540 – RAILWAY AVE, 2ND POLE NORTH OF LORNE AVE
#231 – ERIE ST, 2ND POLE SOUTH OF CAMBRIA ST
#242 – WEST GORE ST, BETWEEN CHURCH & BIRMINGHAM
#680 – FUTURE (ST. VINCENT ST S, NORTH OF WORSLEY)
#693 – LORNE AVE, WEST OF NELSON ST
#694 – LORNE AVE, WEST OF ROMEO ST

FAULT INDICATOR LOCATIONS

68M2
1. 50 LORNE AVE E. (FESTOSO'S)
2. LORNE AVE. 1ST SPAN EAST OF DOWNIE.

68M3
1. 22 NORFOLK ST. (1ST SPAN WEST OF LBS #403)

68M4
1. 54 ROMEO ST S (GALLERY STRATFORD)
2. 74 CHURCH ST (1ST SPAN SOUTH OF DIP #143)

68M5
1. AVONDALE CEMETARY SOUTH OF RAILROAD TRACKS.
2. MORNINGTON ST. AT BATTERSHELL PARK.

68M8
1. TWO SETS ON DOUBLE DIP AT SAMSONITE PARKING LOT OFF OF ONTARIO STREET.

3 PHASE OVERHEAD	
3 PHASE UNDERGROUND	
1 PHASE OVERHEAD	
1 PHASE UNDERGROUND	
3 PHASE TRANSFORMER	80888
1 PHASE LP TRANSFORMER	1638
INLINES	
LOAD BREAK SWITCH	
AIR BREAK SWITCH	
SCADA-MATE SWITCH	
FUSED DISCONNECTS	
CAPACITOR BANK	
CUSTOMER OWNED TRANS.	
M2 FEEDER (FESTIVAL HYDRO)	
M3 FEEDER (FESTIVAL HYDRO)	
M4 FEEDER (FESTIVAL HYDRO)	
M5 FEEDER (FESTIVAL HYDRO)	
M6 FEEDER (HYDRO ONE)	
M8 FEEDER (FESTIVAL HYDRO)	

PLOT DATE: FEBRUARY 2010

Festival Hydro INC.

ELECTRICAL ENGINEERING SECTION

27.6KV DISTRIBUTION MAP
STRATFORD

DRAWN BY: M. KOOY	PROJECT DESIGN: M. KOOY	CHECKED BY: D. ECKEL
DRAWING DATE: 02/21/2006	PROJECT ID: N/A	SCALE: NTS
D. ECKEL MGR. ENGINEERING	B. ZEHR PRESIDENT	DWG. No. N/A

3. 2011 System Reliability Report

2011 SYSTEM RELIABILITY

May 16, 2012

prepared by:

Goran Borovickic EIT
Distribution Engineer

Executive Summary

This report reviews the reliability of the distribution system owned and operated by Festival Hydro, for the year 2011. Comparisons are made to provincial and international standards. Root causes are identified and recommendations made to improve the system reliability. This report is an annual report presented to Festival Hydro management and the Board of Directors. Comments or questions should be directed to the author.

1. BACKGROUND

Festival Hydro is required by the Ontario Energy Board (OEB) to achieve minimum performance standards regarding customer service and system reliability. The standards for reliability are not prescriptive, but the OEB expects utilities to maintain their systems to prevent degradation in the reliability. The OEB anticipates requiring minimum acceptable levels of reliability as part of the second generation of performance based rates. For the present time, a five year rolling average is used and five years worth of data is presented in this report.

Data regarding outages is collected daily and reported every year to the OEB. For system reliability, five indicators are used, and the first two are reported to the OEB.

The standard reliability indices are weighted by customer and presented as averages. For example, a SAIDI of 2.0 means the average customer was off for 2 hours during the entire year. Not all customers on that feeder or in that area were off for 2 hours – some were off for more, some were off for less. Likewise with SAIFI – a SAIFI of 3.2 means some customers had more than 3 outages while some had less. This concept is particularly important when looking at feeder specific data – it is still an average value. The way the indices are calculated means that a 15 minute outage to 5000 customers will have a much greater impact than a 15 minute outage to only 10 customers, even though both outages may have been caused by a tree contact. With a relatively small customer base, it only takes one or two outages to a main feeder in any given year to push the reliability indices higher than average. This could give the impression that the reliability is getting worse, when in reality the actual number of outages is declining and the increase in the reliability indices is more related to chance than poor performance. To account for this, data regarding the number of outages and causes of the outages is also examined and summarized below.

2. RELIABILITY INDICIES

A) System Average Interruption Duration Index (SAIDI) – This is the length of time in hours during the year that power was not available to the average customer.

SAIDI – Historical Performance

Outage Hours/Year

Area	2007	2008	2009	2010	2011	Avg
Ontario Avg[1]	2.38	5.79	2.03	1.73		2.98
FHI - Total	4.18	1.73	1.79	2.09	1.55	2.27
Stratford	2.5	2.13	1.75	2.69	0.90	1.99
68M2	4.6	1.15	2.31	2.01	2.23	2.46
68M3	3.1	4.41	0.87	2.69	1.33	2.48
68M4	3.9	0.26	0.48	2.79	0.25	1.54
68M5	1.1	1.5	2.86	2.84	0.47	1.75
68M8	2.9	1.56	0.4	0.19	1.31	1.27
St Marys	2.2	0.15	0.3	1.64	3.19	1.50
9M1	0.9	0	1.65	0	1.33	0.78
9M2	0.4	0.05	0.44	2.63	1.68	1.04
9M3	1.2	0.1	0.39	0.01	4.57	1.25
9M4	3.1	0.19	0.2	1.87	3.30	1.73

[1] Ontario averages are based on data submitted to the OEB for all Ontario LDCs. Data without loss of supply is not available.

For 2011, the average Festival Hydro customer would have been without power for a total of 1.55 hours for the entire year. Stratford customers would have been without power for 0.90 hours while St. Marys customers would have been without power for 3.19 hours.

The impact of "Loss of Supply" outages is usually negligible for Stratford and St. Marys customers, since both are supplied directly by transformer stations. In 2011 Hydro One related problems had a minor impact on most of the St Marys feeders (Bus failure at the St Marys TS). However, Hydro One related problems had a major impact in the remaining five communities, as over 80% of the customer outage minutes were due to Loss of Supply. This is reflected in the 'FHI-Total' number, which is 1.55 with Loss of Supply included and 1.13 with Loss of Supply excluded.

SAIDI – Excluding Loss of Supply

Outage Hours/Year

Area	2007	2008	2009	2010	2011	Avg
FHI – Total	2.54	1.16	0.57	1.97	1.13	1.47
Stratford	2.5	1.64	0.77	2.50	0.90	1.66
68M2	4.6	1.15	2.06	1.94	2.23	2.40
68M3	3.1	2.66	0.87	2.54	1.33	2.10
68M4	3.9	0.26	0.48	2.79	0.25	1.54
68M5	1.1	1.5	0.56	2.52	0.47	1.23
68M8	2.9	1.56	0.40	0.05	1.31	1.24
St Marys	2.1	0.15	0.29	1.64	3.13	1.46
9M1	0.8	0.00	0.16	0.00	1.22	0.44
9M2	0.3	0.05	0.44	2.63	1.65	1.01
9M3	1.1	0.10	0.33	0.01	4.45	1.20
9M4	2.8	0.19	0.20	1.87	3.25	1.66

B) System Average Interruption Frequency Index (SAIFI) – This is the number of outages (greater than 1 minute) during the year that affects the average customer.

SAIFI – Historical Performance

Number of Outages/Year

Area	2007	2008	2009	2010	2011	Avg
Ontario Avg	2.02	3.27	1.68	1.81		2.20
FHI - Total	4.82	1.86	2.05	2.56	2.28	2.71
Stratford	3.4	2.15	2.02	3.37	2.08	2.60
68M2	3.1	1.26	1.28	4.07	2.19	2.38
68M3	4.2	4.49	2.39	4.61	3.09	3.76
68M4	3.1	0.26	1.08	2.01	0.20	1.33
68M5	3.1	1.14	2.16	3.19	1.97	2.31
68M8	3.2	1.07	2.15	1.15	1.79	1.87
St Marys	4.8	0.76	1.16	2.06	3.90	2.54
9M1	3.6	0	3.84	0.00	2.14	1.92
9M2	1.4	0.06	0.22	2.17	3.48	1.47
9M3	2.6	0.08	1.62	0.01	3.62	1.59
9M4	6.4	1.17	1.22	2.66	4.14	3.12

For 2011, the average Festival Hydro customer would have experienced 2.28 outages greater than 1 minute in length. With Loss of Supply excluded, that number dropped down to 1.8, showing that Loss of Supply had a similar impact as in previous years. In St Marys, Loss of Supply caused an additional outage for each customer.

SAIFI – Excluding Loss of Supply

Number of Outages/Year

Area	2007	2008	2009	2010	2011	Avg
FHI - Total	2.81	1.36	1.21	2.00	1.80	1.84
Stratford	3.4	1.87	1.60	2.53	2.08	2.34
68M2	3.1	1.26	1.17	3.07	2.19	2.14
68M3	4.2	3.49	2.39	3.61	3.09	3.18
68M4	3.1	1.16	1.08	2.01	0.20	2.09
68M5	3.1	1.14	1.16	2.19	1.97	1.56
68M8	3.2	1.07	2.15	0.15	1.79	1.71
St Marys	3.0	0.76	0.88	2.06	2.92	1.92
9M1	1.8	0	0.20	0.00	1.14	0.63
9M2	0.2	0.06	0.22	2.17	2.88	1.11
9M3	1.6	0.08	0.21	0.01	2.57	0.89
9M4	4.3	1.17	1.22	2.66	3.09	2.49

C). Customer Average Interruption Duration Index (CAIDI) – This is the average length of an outage in hours seen by the average customer.

CAIDI – Historical Performance

Average Length of Outage in Hours

Area	2007	2008	2009	2010	2011	Avg
Ontario Avg	9.69	11.15	1.24	1.08		5.79
FHI - Total	0.87	0.93	0.87	0.82	0.68	0.83
Stratford	0.7	0.99	0.86	0.80	0.43	0.76
68M2	1.5	0.91	1.81	0.49	1.02	1.15
68M3	0.7	0.98	0.36	0.58	0.43	0.61
68M4	1.3	0.23	0.44	1.39	1.25	0.92
68M5	0.3	1.32	1.32	0.89	0.24	0.81
68M8	0.9	1.45	0.18	0.16	0.73	0.68
St Marys	0.5	0.193	0.26	0.80	0.82	0.51
9M1	0.3	0	0.42	0.00	0.62	0.27
9M2	0.3	0.89	1.99	1.21	0.48	0.97
9M3	0.4	1.33	0.23	1.00	1.26	0.84
9M4	0.5	0.16	0.17	0.70	0.80	0.47

For 2011, the average length of an outage for FHI customers was .68 hours, or 41 minutes.

CAIDI – Excluding Loss of Supply

Average Length of Outage in Hours

Area	2007	2008	2009	2010	2011	Avg
FHI - Total	0.90	0.85	0.47	0.99	0.63	0.77
Stratford	0.7	0.87	0.48	0.99	0.39	0.69
68M2	1.5	0.91	1.77	0.63	1.07	1.18
68M3	0.7	0.76	0.36	0.70	0.61	0.63
68M4	1.3	0.23	0.44	1.39	0.08	0.69
68M5	0.3	1.32	0.48	1.15	2.35	1.12
68M8	0.9	1.45	0.18	0.35	0.66	0.71
St Marys	0.7	0.193	0.33	0.80	1.07	0.62
9M1	0.4	0	0.76	0.00	1.07	0.45
9M2	1.4	0.89	1.99	1.21	0.57	1.21
9M3	0.7	1.33	1.56	1.00	1.73	1.26
9M4	0.7	0.16	0.17	0.70	1.05	0.56

D) Index of Reliability – This identifies the percentage of the time that service was available during a given year. There are 8760 hours in one year; therefore, 1 hour is equal to 0.011%.

Index of Reliability – Historical Performance

Percentage of Time Available

Area	2007	2008	2009	2010	2011	Avg
Ontario Avg	98.293	99.934	99.977	99.980		99.546
FHI - Total	99.952	99.980	99.980	99.976	99.982	99.974
Stratford	99.971	99.976	99.980	99.969	99.990	99.977
68M2	99.947	99.987	99.974	99.977	99.975	99.972
68M3	99.965	99.950	99.990	99.969	99.985	99.972
68M4	99.955	99.997	99.995	99.968	99.997	99.982
68M5	99.987	99.983	99.967	99.968	99.995	99.980
68M8	99.967	99.982	99.995	99.998	99.985	99.985
St Marys	99.975	99.998	99.997	99.981	99.964	99.983
9M1	99.990	100.000	99.981	100.000	99.985	99.991
9M2	99.995	99.999	99.995	99.970	99.981	99.988
9M3	99.986	99.999	99.996	100.000	99.948	99.986
9M4	99.965	99.998	99.998	99.979	99.962	99.980

In 2011, the average FHI customer could expect the power to be available 99.98% of the time.

E) System Average Automatic Reclosure Index (SAARI) – This is the average number of momentary interruptions (less than 1 minute) seen by the average customer in one year.

SAARI – Historical Performance

Average Number of Momentary Interruptions/Year

Area	2007	2008	2009	2010	2011	Avg
FHI - Total	11.8	11.7	10.22	7.11	10.12	10.2
Stratford	10.75	14.93	12.26	8.88	12.96	12.0
68M2	5	9	26	8	12	12.0
68M3	13	15	7	15	10	12.0
68M4	0	3	9	4	14	6.0
68M5	15	23	17	9	15	15.8
68M8	4	2	2	1	5	2.8
St Marys	26.8	14.14	9.12	4.96	7.74	12.6
9M1	3	5	1	1	3	2.6
9M2	16	6	7	4	4	7.4
9M3	10	4	3	4	16	7.4
9M4	34	16	13	6	7	15.2

In 2011, the average Festival Hydro customer would have experienced 10.1 outages of less than 1 minute in length. (Note that very few Ontario utilities report this index.)

3. DATA ANALYSIS

To get a better understanding of what is happening to the distribution system, the data is analyzed excluding the number of affected customers, excluding Loss of Supply outages (which are upstream of the distribution system) and excluding Scheduled outages (which are not a result of problems with the distribution system).

A) Number Of Outages – The quantity of outages greater than 1 minute in a given year, excluding Loss of Supply and Scheduled. Note that the number of outages does not mean the entire feeder experienced an outage, only that the outage occurred somewhere on that feeder.

Number of Outages/Year

Area	2007	2008	2009	2010	2011
FHI - Total	130	93	85	80	88
Stratford	75	60	44	47	56
68M2	9	9	7	9	6
68M3	25	20	14	11	18
68M4	10	9	8	12	8
68M5	22	19	14	12	20
68M8	9	3	1	3	4
St Marys	24	10	16	17	22
9M1	2	0	1	0	0
9M2	6	2	1	9	5
9M3	5	2	2	1	7
9M4	11	6	12	7	10

B) Number Of Feeder Lockouts – The quantity of outages greater than 1 minute in a given year that affected the entire feeder (Feeder Lockout).

Number of Feeder Lockouts/Year

Area	2007	2008	2009	2010	2011	Total
FHI - Total	24	8	11	18	18	79
Stratford	15	7	7	14	8	51
68M2	3	1	1	3	1	9
68M3	4	4	2	5	3	18
68M4	3	1	1	2	0	7
68M5	2	1	2	3	2	10
68M8	3	0	1	1	2	7
St Marys	9	1	4	4	10	28
9M1	2	0	2	0	0	4
9M2	0	0	0	1	4	5
9M3	2	0	1	0	3	6
9M4	5	1	1	3	3	13

<u>C) Number Of Outages by Cause</u> – The quantity of outages greater than 1 minute for each cause in a given year, excluding Loss of Supply and Scheduled.

Number of Outages/Year

Cause	2007	2008	2009	2010	2011	Total
Adverse Weather	15	8	5	11	9	48
Defective Equipment	46	39	26	39	32	182
Foreign Interference	47	25	24	19	34	149
Human Error	1	2	3	1	0	7
Lightning	3	8	2	1	4	18
Tree Contacts	14	9	17	6	9	55
Unknown	4	2	8	3	0	17
Total	128	93	85	80	88	474

4. TREND ANALYSIS

SAIDI (duration)

The duration of the average outage decreased from 2010 and was the lowest in the past five years. Loss of Supply issues had a significant impact on the duration, accounting for 37% of total customer outage minutes in 2011. The majority of the Loss of Supply minutes were in the Seaforth area.

SAIFI (frequency)

The frequency of outages also decreased from the 2010 level, but was still slightly higher than in 2008 and 2009. Loss of Supply accounted for 10% of the total in 2011.

SAARI (frequency of momentary outages)

The frequency of momentary outages increased in 2011 compared to 2010. Both Stratford and St. Marys saw an increase of about 50%. The frequency for the entire FHI system was right on par with the 5 year average.

Number of Outages (excluding Loss of Supply and Scheduled)

The number of outages per year increased slightly in 2011. In St. Marys the number of outages rose for a 4th straight year, while in Stratford the downward trend from the previous 4 years stopped.

Number of Feeder Lockouts (outages to entire feeder)

The number of outages affecting entire feeders was the same as in 2010 for the entire system. Numbers in Stratford decreased, while in St. Mary's the number more than doubled, mainly due to storms and tree contacts.

Number of Outages by Cause (excluding Loss of Supply and Scheduled)

Adverse weather outages decreased slightly in 2011, with the number being close to the 5 year average.
Defective equipment outages also decreased slightly in 2011, with the number being lower than the 5 year average.
Foreign interference outages (animals, vehicles) almost doubled from the 2010 level, mainly due to animal contacts (over 20).
There were no outages caused by Human Error in 2011.
Lightning outages were up in 2011. All outages caused by lightning occurred on the same day.
Tree contact outages were below average in 2011, but increased slightly from 2010.
There were no outages in 2011 where the cause was unknown.

Overall the number of outages greater than 1 minute increased slightly compared to 2010, mainly due to foreign interference (almost doubled compared to 2010). There was also a small increase in tree contacts, mostly due to storms, and lightning. The Reliability Indices improved in Stratford, but were much worse in St. Marys because of weather related issues. Overall, the numbers are typically lower than the 5 year average.

5. DETAILED ANALYSIS

DURATION:

The 8 longest outages in terms of customer minutes were caused by adverse weather and foreign interference. Those 8 outages accounted for just over 50% of the total customer minutes in 2011. Defective equipment was only responsible for 5% of the total customer minutes.

FREQUENCY:

SAIFI was also adversely impacted by most of the 8 outages that affected the SAIDI index. There was also 1 equipment failure (elbow) and one of the outages was caused because there was a hold-off on the feeder. One other outage was caused by a customer who was cutting down a tree and a limb landed on a circuit. Without these three outages, SAIFI improves from 2.28 to 1.55.

OUTAGE CAUSES:

In 2011, the quantity of outages increased, but was average over the past 3 years. The number of affected customers decreased.

Loss of Supply outages primarily affected the Seaforth & Area customers due to various issues. St. Marys customers were also affected by two separate loss of supply problems, while Stratford had no outages attributed to loss of supply.

Adverse Weather improved slightly in 2011. Most of the outages were in the St. Marys area, on the M2 and M4 feeders. No major damage was caused. The M2 problem has been fixed by de-energizing 2 of the phases in the problem area.

Foreign Interference increased significantly in 2011, almost doubling from the previous year. The increase was mainly in Stratford, which saw the number of animal contacts double from 9 to 18. Re-insulation projects will continue to help reduce the number of animal contacts.

Tree Contacts increased in 2011 to from 6 to 9. The outages that affected the most customers were due to storms.

Defective Equipment outages decreased in 2011and the number of customers affected was much lower than in the previous year and the 5 year average. Just like in the previous year most of the outages were due to failures of minor equipment such as fuses, arrestors, and connectors which affected only small groups of customers at a time. There were 2 equipment related outages in Stratford that affected entire feeders. One was a defective arrester and the other a primary elbow. Due to the low number of equipment failures, there are no discernable trends and the number is still quite low considering the amount of equipment in the field. Our policy of re-building aging infrastructure before it becomes unreliable prevents many problems associated with old equipment.

Lightning typically causes only momentary outages, although occasionally we have equipment damage. In 2011 there were 4 outages attributed to lighting, which is higher than in the previous 2 years. 3 of those were on the 68M2 feeder in Stratford. Lightning arrestors are installed with all overhead equipment such as transformers and cable terminations which provides a good level of protection.

The number of **Unknown** outages was zero in 2011, which was the first time this has happened since the stats were being kept in 2003.

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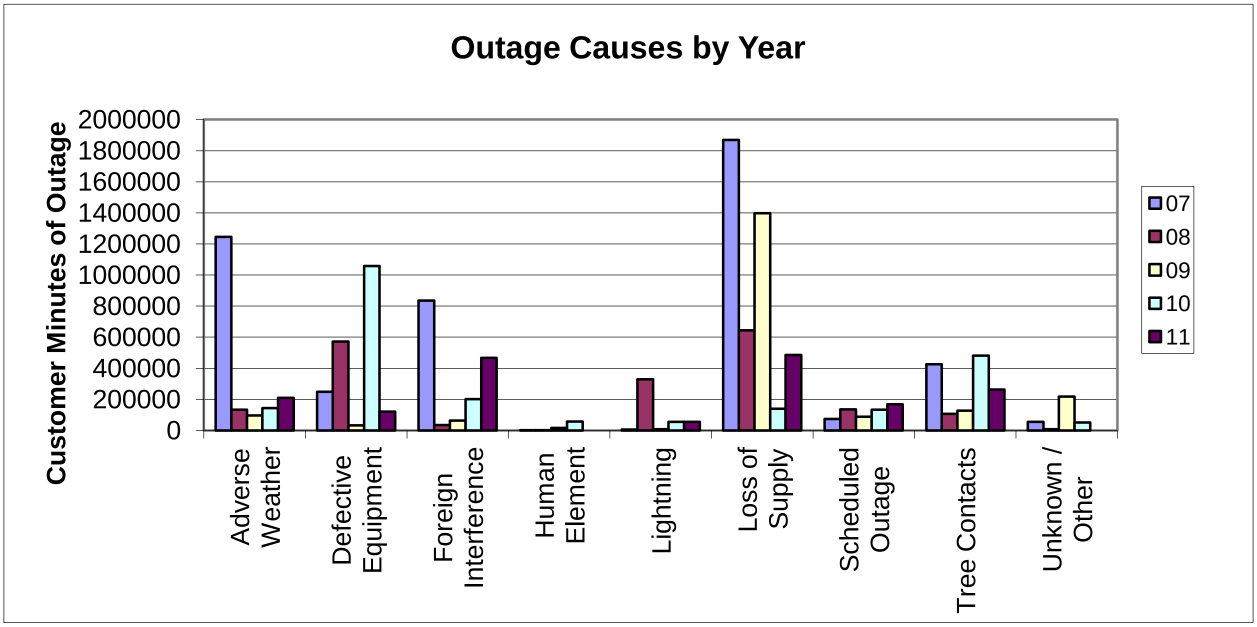


Weather = outage caused by high winds, blowing debris, ice, flooding
Equipment = outage caused by failure of distribution equipment
Foreign Interference = outage caused by animals, vehicles, vandalism
Human Element = outage caused by human error
Lightning = outage caused by lightning strike
Loss of Supply = Outages on Hydro One System Supplying Festival Hydro
Scheduled = planned outage by Festival Hydro needed to upgrade system
Tree Contact = outage caused by contact with tree or tree limb
Unknown = no cause could be found

POOR PERFORMING FEEDERS:

The outage database used since 2003 allows for detailed analysis of individual feeders. Using this database, the top 3 worst performing feeders have been identified using customer minutes of outage as the primary criteria (excluding scheduled outages, and loss of supply outages).

The decision to rank the feeders based on customer minutes of outage is based on the assumption that the objective is to improve the overall system reliability by identifying those areas that contribute the most to the overall indices of SAIDI and SAIFI. This will have the effect of decreasing the duration and frequency of outages to the average customer. Due to this concept, the feeders with the most customers naturally become the targets for potential improvements while feeders with fewer customers may have poorer values for feeder specific SAIDI and SAIFI. For example, in 2007 the feeder with the worst SAIDI was the 68M2, yet it ranks in the middle of the pack when customer minutes of outage are used as the ranking method since it has relatively fewer customers than many of the other feeders.

The chart below ranks the Stratford and St Marys feeders from worst to best based on the cumulative customer minutes of outage over the past 5 years.

Feeder	2007	2008	2009	2010	2011	Total	
68M3	629566	898788	172235	438320	257980	2396889	33%
68M5	292350	449835	149624	734374	150101	1776284	25%
68M4	498472	34091	45505	348356	11255	937679	13%
9M4	302850	20551	14950	194681	348926	881958	12%
68M2	248565	62003	111022	104847	66720	593157	8%
68M8	128970	70170	7750	340	56370	263600	4%
9M3	32326	3028	1963	65	128105	165487	2%
9M2	7195	1550	4130	78930	47750	139555	2%
9M1	2430	0	170	0	0	2600	0%
Total	2142724	1540016	507349	1899913	1067207	7157209	

1. <u>68M3 Feeder in Stratford</u>

   This feeder supplies primarily residential customers in the south-central area of Stratford, and is almost exclusively overhead distribution in older residential areas. The proximity to mature trees makes this feeder susceptible to squirrel contacts, and tree contacts, but these causes have dropped off with the installation of the insulated brackets and improved tree trimming. Unfortunately 2 of the worst 3 outages occurred because of animal contacts on 2 riser poles that were not re-insulated yet. The worst outage was due to a customer cutting down a tree and a tree limb falling on a 3 phase line. Just those three outages were responsible for almost 90% of the total customer minutes on the M3 feeder.

2. <u>68M5 Feeder in Stratford</u>

   This feeder supplies about 5000 customers in the west third of Stratford. It is the longest feeder with the most exposure, making it the most susceptible to weather and tree contacts. In 2010, there were 5 squirrel contacts and 1 tree contact. The worst outage was due to a squirrel contact, but only because there was a hold-off on the feeder at the time.

3. <u>68M4 Feeder in Stratford</u>

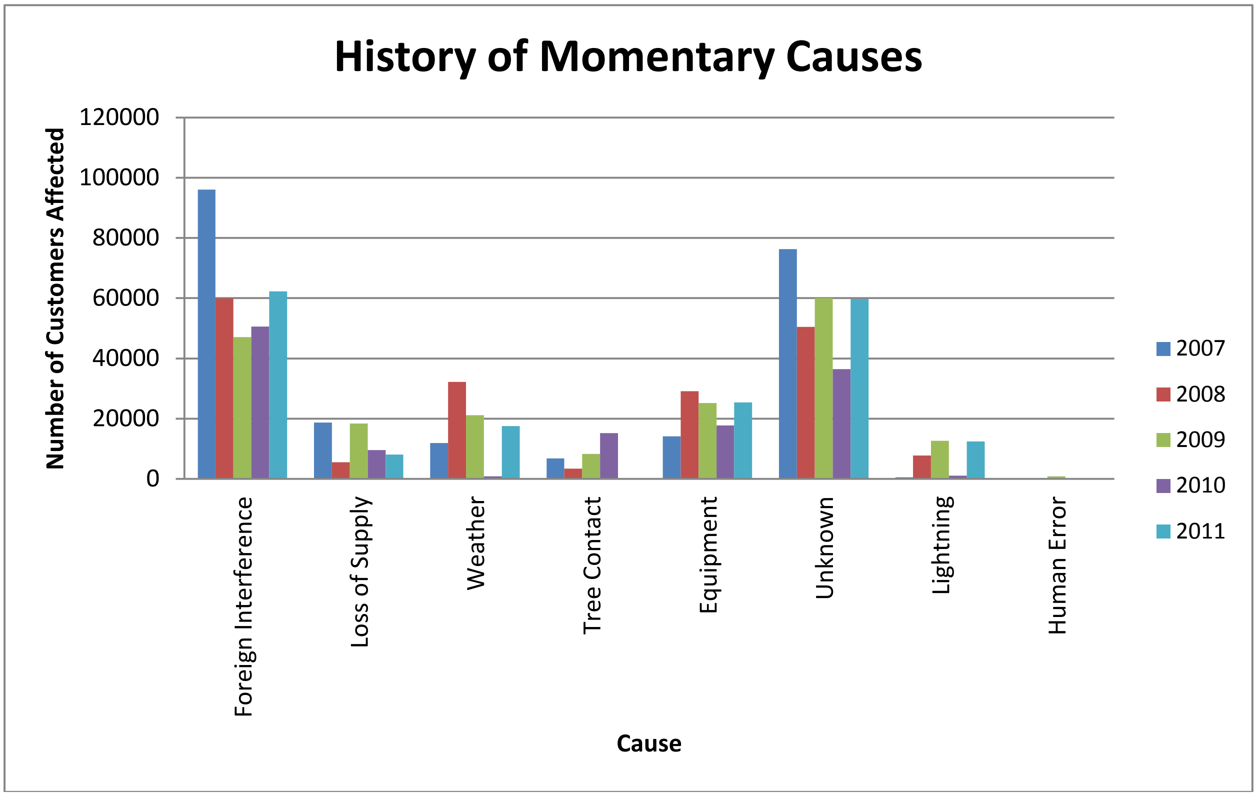
   This feeder supplies the downtown core of Stratford out to Monteith, and has a long section of underground. This feeder was actually the second best performing feeder in 2011, but still remains in the top 3 poor performing list because of poor performances in 2007 and 2010.

MOMENTARY OUTAGES:

The SAARI index – System Average Automatic Reclose Index measures the number of outages less than 1 minute, as seen by the average customer. The graph on the next page shows the causes of the outages for the past five years based on number of customers affected.

Overall, there was an increase in the number of customers affected compared to the previous year. The only category that had a significant reduction was tree contacts, as there were no recorded momentary outages due to it in 2011. Most other categories saw an increase, but overall the number of customers seeing momentary outages were close to the average of the last 5 years.

Many utilities do not report their momentary outages, so it is difficult to determine if our numbers are higher or lower than similar utilities. The system in Stratford is somewhat unusual in the distribution of customers, such that 25% of all our customers are on the 68M5 feeder, so every reclose on that feeder affects over 5000 customers.



6. RECOMMENDATIONS

CAPITAL BUDGET ITEMS

We are taking a multi-solution approach to improving reliability in Festival Hydro's service territory. We are continuing a reinsulation project that will see us rebuild feeder lines using insulating material as opposed to conductive brackets and crossarms. This project will probably take 10 years to fully complete ,but we hope to see improvements each year of the implementation. Next we are beginning a program to replace existing live front PMH switchgear to a deadfront model. We hope this program will see a reduction in equipment failures due to the new design and finally, we are in the process of building a new transformer station in Stratford. This build will reduce feeder length by a half. The shorter feeder should have a dramatic affect on system reliability. The station should be operational in 2013.

OPERATING BUDGET ITEMS

The Operations Manager will continue to meet with the City of Stratford and Town of St Marys representatives on a regular basis to review tree trimming requirements and performance.

We are also starting a wood pole inspection program which should help us identify aged infrastructure for replacement before failure.

This information has been prepared by Goran Borovickic, Distribution Engineer EIT. Any questions should be directed to the author.

Festival Hydro Inc.
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PO Box 397
Stratford, ON N5A 6T5
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Distribution Engineer EIT
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4. City of Stratford Economic Development Letter

ALLAN O'NEILL
ECONOMIC DEVELOPMENT AND PLANNING CONSULTANT
519-301-7076

August 9, 2011

Larry Appel
Director of Economic Development
City of Stratford

Dear Mr Appel

Thank you for the opportunity to participate in the City of Stratford Economic Development Office Business Visitation Program.

I have had the privilege of visiting many companies in Stratford, both large small. I have outlined the feedback from those visits previously. There is one matter that I feel is of particular note, and I have thus out lined it in this letter.

One issue that came up time and again in discussions with business owners and managers is the unreliability of the electrical service in the City of Stratford. The concern is with what I will call 'mini power breaks', interruptions in the electrical power that lasts only seconds, but have a very serious impact on industrial operations and on use of computers. These breaks occur often, perhaps several times a month.

The impact on industrial operations cannot be overstressed. These 'mini power breaks' result in shutdowns of the operation, sometimes shutdowns of the computers and robots that are used in the manufacturing process, and where plastic extrusion is involves the shutdowns are even more problematic.

In my many years of working in Economic Development in various municipalities, it is my conclusion that constant uninterrupted electrical power supply is of prime importance in attracting and in retaining manufacturing operations and computer related businesses. Businesses usually research the number of power outages that occur in a specific location before making the decision to locate.

It is my belief that the City of Stratford is harming its ability to attract new industries and high-tech businesses with the power supply situation in its current state.

I recognize that dealing with this 'mini power break' issue in the short term is difficult, because it will likely require infrastructure improvements. Nevertheless, it is a matter that should be rectified as soon as is reasonably possible. Often the cost of not investing in infrastructure upgrades is greater in the long run than not investing.

Although the matter of power supply was raised on numerous occasions, in other respects the businesses owners and managers in the City of Stratford are generally satisfied with the city and with its administration.

Respectfully submitted

Allan J. O'Neill
Economic Development
And Planning Consultant

5. 1991 Planning Report

Future Supply to Stratford and St. Marys

Background

Current load forecasts indicate that St Marys 115-13.8 kv TS requires relief by winter 1991/92 and that Stratford 230-27.6 kv TS requires relief as soon as FAG Bearings increases its load (summer 1992).

The following information summarizes the results of a preliminary evaluation of alternatives for future supply of Stratford and St Marys.

(A) Supply to Stratford

Plans for future supply to Stratford are affected by the following factors/assumptions:

- Load transfers from Stratford TS to Detweiller TS are not feasible as they would overload those facilities.
- Increasing capacity at Stratford TS by replacing the existing 50/83 MVA transformers with 75/125 MVA units would not provide adequate capacity for the study period and is therefore not economic

(B) Supply To St Marys

Plans for future supply to St Marys are affected by the following factors/assumptions:

- Converting 13.8 kv load to 27.6 kv supply and dismantling the existing St. Marys TS is not economic.
- Both St Marys PUC and Retail Customers prefer future supply at 27.6 kv.
- A 1980 study recommended that future capacity be provided at 27.6 kv. On the basis of this recommendation, St Marys PUC and Retail Customers have been building lines adequate for future use at 27.6 kv.
- Adding capacity at 27.6 kv would provide the opportunity for future transfer capability to surrounding stations and thus increase flexibility and reliability.
- Supply at 27.6 kv would increase capacity utilization - load from the surrounding area could be supplied from the new facility (ie. Centralia TS load could be supplied from new 27.6 kv facilities at St Marys TS)
- Distribution line losses are lower at 27.6 kv

- Providing dual 13.8/27.6 kv capacity by installing either dual voltage (115-13.8/27.6 kv) transformers or single secondary voltage transformers with a 27.6-13.8 kv autotransformer at St Marys TS is uneconomic.

- It is recognized that St Marys TS is an old station and some rehab work will be required to retain 115-13.8 kv facilities (at a cost of approximately $850,000).

- Load transfers at 27.6 kv from St Marys TS to Centralia TS are not feasible as they would overload those facilities.

Alternatives

Based on the above, the alternatives considered are as follows:

Stratford TS

- provide a 230-27.6 kv, 50/83 MVA TS
- provide a 230-27.6 kv, 75/125 MVA TS
- load transfers to Seaforth TS
- load transfers to a new TS built for joint supply of St Marys and Stratford

St Marys TS

- provide a 115-27.6 kv, 20/34 MVA DS
- provide a 115-27.6 kv, 25/41 MVA TS
- load transfers to Stratford TS
- load transfers to a new TS built for joint supply of St Marys and Stratford

Six alternatives for future supply to Stratford and St Marys were developed and are described in the attachments. The earliest possible date for providing relief to St Marys TS is 1993. Interim measures will be considered to provide emergency relief to St Marys TS in 1991 and 1992.

An economic comparison of the six alternatives considered for future supply to the Stratford and St Marys area was carried out and the results are summarized below. Results are given for the 'most likely' load growth scenario and for a 'high' load growth scenario. It is noted that the load forecasts (and thus the required in-service dates) are still preliminary and need to be refined.

	Most Likely Forecast			High Forecast		
Alternative	Present Value	Residual Value	Net Present Value	Present Value	Residual Value	Net Present Value
1	15.0	4.0	11.0	21.5	8.6	12.9
2	23.7	6.1	17.6	23.7	6.1	17.6
3	17.5	4.7	12.8	17.8	4.9	12.8
4	17.6	5.0	12.7	24.0	8.1	15.9
5	20.7	5.4	15.3	25.9	8.7	17.3
6	25.2	6.7	18.5	30.4	10.0	20.4

It is noted that the above analysis does not include PUC distribution costs, distribution line losses, and HV line losses.

This analysis shows:

- Alternative 1 is the lowest cost alternative
- Alternatives 3 and 4 are economically equivalent and have the second lowest cost.

All three alternatives include building a 115-27.6 kv, 20/34 MVA DS at the St. Marys TS site.

Preliminary Conclusions

Supply to Stratford

Provide additional 230-27.6 kv capacity for supply to the city of Stratford TS;

- on existing Stratford TS site, or
- on a new site

Supply to St Marys

1. Existing 13.8 kv supply to the town of St Marys is to be maintained within existing 13.8 kv capacity (23.8 MVA).

2. All retail load in the area is to be supplied at 27.6 kv.

<u>Recommendations</u>

1. Initiate work to provide 115-27.6 kv supply from St Marys TS.

2. Finalize joint study with Stratford PUC regarding best location for adding 230-27.6 kv capacity.

Alternative 1

Year	Description	Capital Cost Year Shown ($M)	Present Value January 1991 ($M)
1992	Transfer Mitchell DS from Stratford TS to Seaforth TS	0.27	0.22
1993	Build a 115-27.6kV, 20/34MVA DS at St. Marys TS	3.94	2.99
1994	Build a 230-27.6kV, 50/83MVA DESN at Stratford TS	12.83	9.07
1997	Transfer Mitchell DS from Seaforth TS to Stratford TS	0.36	0.17
	Transfer Kirkton DS from Centralia TS to St. Marys TS (temporary 3 year transfer)	1.05	0.49
2000	Uprate Centralia TS	5.88	2.07
1992-2011	Distribution facilities as required		

Total Present Value	15.01
Residual Value	4.04
Net Present Value	10.97

Alternative 2

Year	Description	Capital Cost Year Shown ($M)	Present Value January 1991 ($M)
1992	Transfer Mitchell DS from Stratford TS to Seaforth TS	0.27	0.22
1993	Build a 115-27.6kV, 25/41MVA DESN at St. Marys TS	12.02	9.15
1994	Build a 230-27.6kV, 75/125MVA DESN at Stratford TS	16.54	11.56
1997	Transfer Mitchell DS from Seaforth TS to Stratford TS	0.36	0.17
	Transfer Kirkton DS from Centralia TS to St. Marys TS (temporary 3 year transfer)	1.05	0.49
2000	Uprate Centralia TS	5.88	2.07
1992-2011	Distribution facilities as required		
		Total Present Value	23.66
		Residual Value	6.07
		Net Present Value	17.59

Alternative 3

Year	Description	Capital Cost Year Shown ($M)	Present Value January 1991 ($M)
1992	Transfer Mitchell DS from Stratford TS to Seaforth TS	0.27	0.22
1993	Build a 115-27.6kV, 20/34MVA DS at St. Marys TS	3.94	2.99
1994	Build a 230-27.6kV, 75/125MVA DESN at Stratford TS	16.54	11.56
1997	Transfer Mitchell DS from Seaforth TS to Stratford TS	0.36	0.17
	Transfer Kirkton DS from Centralia TS to St. Marys TS (temporary 3 year transfer)	1.05	0.49
2000	Uprate Centralia TS	5.88	2.07
1992-2011	Distribution facilities as required		
		Total Present Value	17.50
		Residual Value	4.68
		Net Present Value	12.82

Alternative 4

Year	Description	Capital Cost Year Shown ($M)	Present Value January 1991 ($M)
1992	Transfer Mitchell DS from Stratford TS to Seaforth TS	0.27	0.22
1993	Build a 115-27.6kV, 20/34MVA DS at St. Marys TS	3.94	2.99
1994	Transfer Wardburg DS to Seaforth TS	1.69	1.08
1995	Build a 230-27.6kV, 50/83MVA DESN at new site 'A'	17.10	10.61
1997	Transfer Mitchell DS from Seaforth TS to Stratford TS	0.36	0.17
	Transfer Kirkton DS from Centralia TS to St. Marys TS (temporary 3 year transfer)	1.05	0.49
2000	Uprate Centralia TS	5.88	2.07
1992-2011	Distribution facilities as required		
		Total Present Value	17.62
		Residual Value	4.96
		Net Present Value	12.66

Alternative 5

Year	Description	Capital Cost Year Shown ($M)	Present Value January 1991 ($M)
1992	Transfer Mitchell DS from Stratford TS to Seaforth TS	0.27	0.22
	Transfer Wardburg DS from Stratford TS to Seaforth TS	1.52	1.21
1993	Transfer Science Hill DS, ST. Marys DS and Campbell Soup to Stratford TS	2.64	1.88
1995	*Build a 230-27.6kV, 75/125MVA DESN at new site 'A' (*Required in 1994)	20.56	13.70
1997	Uprate Centralia TS	5.02	2.43
	Transfer Mitchell DS from Seaforth TS to Stratford TS	0.36	0.17
2000-2001	Transfer St. Marys PUC load to new DESN	3.15	1.06
1992-2011	Distribution facilities as required		
		Total Present Value	20.67
		Residual Value	5.36
		Net Present Value	15.31

Alternative 6

Year	Description	Capital Cost Year Shown ($M)	Present Value January 1991 ($M)
1992	Transfer Mitchell DS from Stratford TS to Seaforth TS	0.27	0.22
	Transfer Wardburg DS from Stratford TS to Seaforth TS	1.52	1.21
1993	Transfer Science Hill DS, ST. Marys DS and Campbell Soup to Stratford TS	2.64	1.88
1995	*Build a 230-27.6kV, 75/125MVA DESN at new site 'B' (*Required in 1994)	28.16	18.83
1997	Uprate Centralia TS	5.02	2.43
	Transfer Mitchell DS from Seaforth TS to Stratford TS	0.36	0.17
2000-2001	Transfer St. Marys PUC load to new DESN	1.38	0.47
1992-2011	Distribution facilities as required		
		Total Present Value	25.20
		Residual Value	6.71
		Net Present Value	18.49

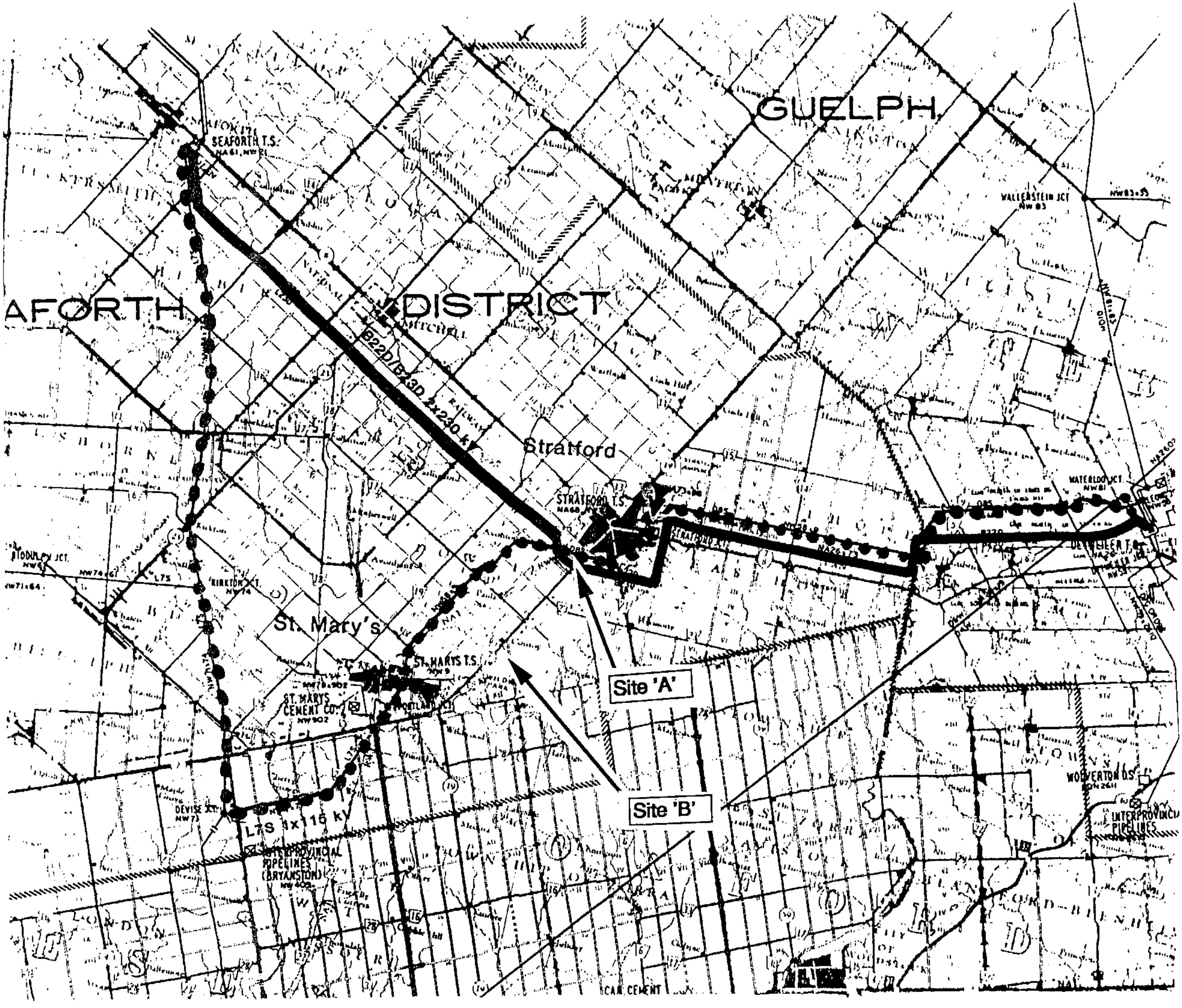


FIGURE 4: ST. Mary's Stratford and Surrounding Area

6. 2004 LTR Study

DRAFT

Stratford TS LTR Study

August 11, 2004

Purpose
To determine how future loads in the Stratford area will be supplied.

Existing Facilities
Existing facilities are shown in Figure 1.
The station consists of 2x50/83 MVA transformers operating at 230/27.6 kV.
There are 8 feeders. 5 belong to Festival Hydro and 3 to Hydro One Dx.
The existing station 10-day summer LTR and its constraints are shown below:

	10-day Summer LTR
T1 unit (X4346/2)	117 MVA @28.6 kV, hot spot 123.9° C for 55°C rise unit, respecting 0.2% aging limit 121 MVA @28.6 kV, hot spot limit of 130° C for 55° C rise unit, aging is ignored
T2 unit (289734)	136 MVA @28.6 kV, hot spot 141.9° C for 65° C rise unit, respecting 0.2% aging limit 150 MVA @28.6 kV, hot spot limit of 150° C for 65° C rise unit, aging is ignored
Metering CT - 2400-5A	133.5 MVA @28.6 kV, 2700A continuous, 30° C
T1, T2 breaker - 2500A	128 MVA @28.6 kV, 2600A continuous, 30° C 133.7 MVA @28.6 kV, 2700A for 24 hour (10 days maximum per year), 30° C

Historical Loads
The station load is summer critical.
The summer 10-day LTR of the station is 117.3 MVA.
The peak summer loading at the station is given in the table below.

Expected Future Loads
Future Loads are expected to grow at 1% based on information from Festival Hydro and Hydro One Dx. Projected loads are shown in table below:

	2001	2002	2003	*2004	*2005	*2006	*2007	*2008	*2009	*2010
Summer Peak in MVA	107.61	114.7	108.42	111.3	112.4	113.6	114.7	115.9	117.1	118.2

* - Estimated peak load based on the average of 2001, 2002 & 2003 and 1% load growth.

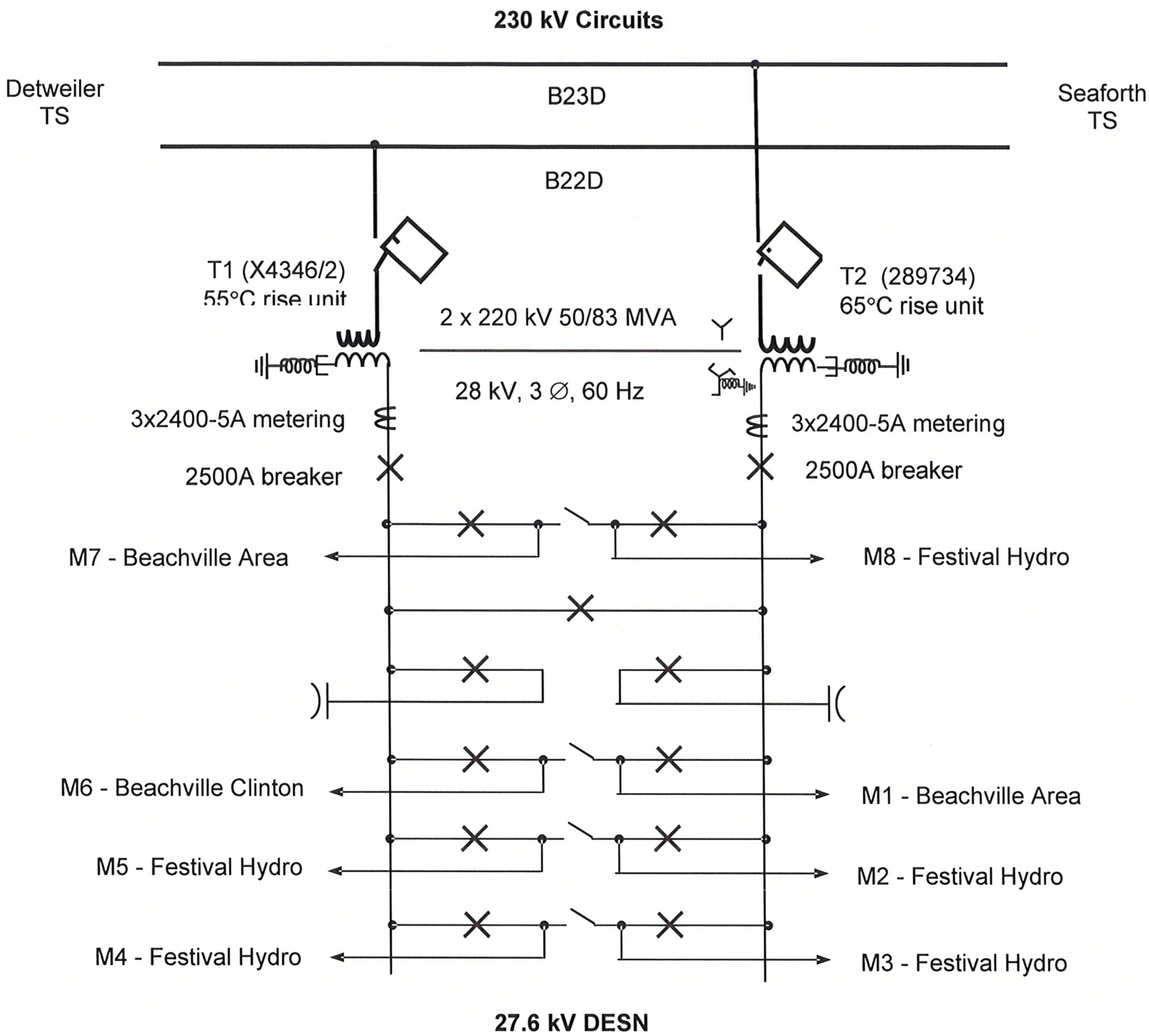
Need
Based on 1 % load growth there is no overload issue until 2010.

Options
1. Upgrade transformers

The station summer LTR capacity is limited by the transformer T1 to 117MVA. If aging is ignored and the unit is operated to 130C hot spot limit, the unit is capable of approximately 121MVA (@28.6KV.

Recommendation

The station load is not expected to reach the station LTR until 2010 based on the load growth of 1%. The opportunity exists to increase the LTR capacity from 117 MVA to 121 MVA by operating T1 at 130 C. Forecasted loads/need should be reviewed on an annual basis.



Stratford TS – LTR Study
Existing 230/27.6 kV DESN
Figure 1

7. 2008 December Meeting Minutes

MINUTES OF MEETING

Hydro One / Festival Hydro Meeting

DATE: December 2, 2008

ATTENDEES:

Joe Taylor	Hydro One
Lyla Garzouzi	Hydro One
Cliff Roach	Hydro One
Tim Stafford	Hydro One
Jac Vanderbaan	Festival Hydro

Minutes of Meeting

The purpose of this meeting was to discuss the addition of a potential new 10Mw customer in the Stratford area.

Background

Festival Hydro was approached by a consultant during the summer of 2008 regarding a company looking to build a data facility in the Stratford area. Estimated load was 20MW. Initial discussions were held with HON in July 2008. At that time, Stratford was one of several locations being considered by the client. The client has now apparently narrowed the search to two locations, one of which is Stratford. The initial load is to be approximately 10MW with an expansion to 20MW by 2017. Whereas the preferred site location is divided between HON and Festival Hydro service territory, the actual facility will apparently be built in the Hydro One service territory.

Discussion

Lyla provided the 2008 summer peak load for Stratford TS. The peak was 113MVA and the LTR is 117MVA.
Jac suggested that earlier discussions had shown there to be some 14MVA of capacity left at Stratford TS and hence was concerned that this capacity was no longer available. It was suggested that perhaps a load transfer was the cause of the higher peak value.
ACTION – Cliff to verify Stratford TS peak values and confirm back.

Jac indicated that Festival can supply the new facility from their existing feeders. HON questioned the loading of the Festival feeders as it was believed that Festival did not have any remaining capacity on their feeders. Jac indicated that they will operate their 27.6kV feeders at up to 650A if necessary and their intention is to supply the customer from M2.

Lyla suggested that HON Dx also has a plan to supply this customer. The plan involves the transfer of some load from the M7 to the M1 and the subsequent extension of M7 to pick up the customer. Jac indicated that HON Dx will have to deal with a forested area which is deemed to be a protected area. Jac indicated that Festival has already provided a cost to the consultant regarding connection.

The customer has requested a redundant supply hence HON asked if Festival would be willing to provide back-up through their system - Jac indicated that he would. It was also learned that the customer will have UPS capability of up to 15 minutes so a break before make supply configuration would be okay.

It was learned that the customer plans to build a second facility at the north end of town in HON territory once they reach their capacity at the proposed southern location.
Jac indicated that they have given the proponent a two year time line to get an appropriate supply to the site. The customer is expecting to make a decision (i.e. preferred location) in mid-December followed by ground breaking in early 2009.

Preliminary studies have been run (by HON) for the increased 10MW on Stratford TS. One scenario indicates that with the loss of one of the 230kV supply lines, there would be voltage problems on the 115kV system. This means that a capacitor bank would be required on the 115kV system.
It was also suggested that one transformer at Stratford TS could be changed out with one that has a larger MVA rating. Currently one transformer at the site is larger than the other. This would provide approximately 133MVA of capacity from the station.
ACTION – Cliff will verify the availability of a spare transformer in the HON system.

It was suggested that HON proceed with the upgrade at Stratford TS if the new customer materializes. The cap bank installation on the 115kV system would also need to proceed. If however, the customer does NOT materialize, Jac indicated that he would prefer to focus on a new TS verses the upgrade work at Stratford TS.
ACTION – Jac to confirm customer decision as soon as it is known.

With respect to a new TS, the preferred location for Festival Hydro would be on the south side of town. This would allow for redundancy of supply into the downtown core as well as other operational flexibility. It would also allow some relief to occur at Stratford TS. Festival would like to see the new capacity within the next 5 years. Some potential sites have been investigated by Festival Hydro. Initial indications are the preferred sites would require minimal environmental assessment activity. The new TS option is supported by the Festival Board but dollar figures would have to be presented to move the project forward.
Lyla suggested that using the existing Stratford TS location for a new DESN would potentially avoid the new for any environmental assessment. She stated that there was sufficient land at the site for an additional DESN.

PREPARED BY: Joe Taylor

8. 2009 Hydro Load Forecast

	Year	PLI (0.9) Adjusted Load		
		Cum. Load Growth - MW		
		Low	Med	High
	2010	4.43	5.64	6.72
	2011	5.51	8.48	10.41
	2012	6.81	11.54	14.33
1	2013	7.44	14.15	17.79
2	2014	7.94	15.63	20.13
3	2015	8.48	16.89	22.02
4	2016	8.97	17.93	23.69
5	2017	9.33	18.74	25.13
6	2018	9.69	19.55	26.57
7	2019	10.05	20.36	28.01
8	2020	10.32	20.99	29.27
9	2021	10.55	21.48	30.30
10	2022	10.77	21.98	31.34
11	2023	11.00	22.47	32.37
12	2024	11.22	22.97	33.41
13	2025	11.45	23.46	34.44
14	2026	11.67	23.96	35.48
15	2027	11.90	24.45	36.51
16	2028	12.12	24.95	37.55
17	2029	12.35	25.44	38.58
18	2030	12.57	25.94	39.62
19	2031	12.80	26.43	40.65
20	2032	13.02	26.93	41.69
21	2033	13.25	27.42	42.72
22	2034	13.47	27.92	43.76
23	2035	13.70	28.41	44.79
24	2036	13.92	28.91	45.83
25	2037	14.15	29.40	46.86
26	2038	14.37	29.90	47.90

9. 2008 June Planning Meeting Minutes

MINUTES OF MEETING

Stratford TS & St. Mary's TS Capacity Planning:

DATE OF MEETING: June 4,2008

ATTENDEES:
Tom Kydd -HON
Cliff Roach- HON
Alex Urbanowicz-HON
Gerry Hendriksen- HON
Jac Vanderbaan- Festival
Bill Smith- Festival

Copy: Lyla Garzouzi

A meeting was held as a follow up to the May25,2006 mtg. regarding Allocated Capacity and Stratford TS LTR.

AGENDA ITEMS :

1.0 Review recollection of last years mtg, wrt Stratford TS- all
2.0 Review the updated Stratford TS loading – Cliff
3.0 Review HON Dx feeder loading, expected growth, needs , etc – Gerry
4.0 Stratford TS sustainment matters –Tom
5.0 Review Festival's projected load forecast and plans on Stratford TS - Jac
6.0 Review estimated cost for a new 50/83 MVA TS. – Cliff & Alex
7.0 Review proposed location/site for a new TS

DISCUSSED:

1.0 At Stratford TS there was ~15MW of capacity. The St. Marys TS was recently rebuilt and capacity was not a concern.

2.0 In Stratford there have been some inquiries over the year that if they were to come to fruition would add 8 to 20 MW of new load. However offsetting possible new load is the fact that 3 to 4 factories have shut down. In St. Mary's DANA has shut down operations. Cliff provided a historical load summary table for Stratford TS and an updated load forecast. The load forecast took into consideration 5 Stratford feeder forecast and the 3 HON Dx feeder forecast. The total forecast indicates that the TS will be at LTR in year 20019. St. Mary's TS is of no concern and Cliff provided the historical load data to date.

3.0 Gerry advised that he was no longer the HON Distribution Planner for the area. His input at the mtg was to basically "close the loop" with respect to the discussions which were initiated last year. The new Planner is Lyla Garzouzi. HON Dx's load from Stratord is ~24MW. Embedded in HON Dx's supply is some Erie Thames load; the town of Tavistock. HON's load forecast is 1% per year till the 2019 date and is expected mostly from the residential sector which peaks around supper. Jac indicated an interest in having a joint look at Distribution planning for the area to make better use of the forth coming capacity allocations.

ACTION: Cliff & Gary arrange

4.0 Tom provided an overview of the sustainment work that had been carried out at Stratford TS. The main focus was on replacing 2 capacitor breakers. Other replacement or maintenance work was planned to take advantage of outages. He provided a table illustrating the condition of various station components and their condition assessment. The transformers have been tested and results are good. Generally speaking the station is in good shape with only one recent animal contact recorded. Hydro Tx's delivery point performance reporting is quite different that that of Festival's, which is based on secondary interruptions. Festival has reliability concerns such as momentaries due to animal and tree contacts.

5.0 Further to (2.0), Jac indicated that with expected new industrial load possibilities the existing transformer station is in the wrong location.

6.0 Cliff presented some recent illustrative examples of costs incurred in building new TSs:

- Option 1: 230/27.6kV with one 25/41 MVA transformer and 4 feeders
Cost: say $14M
- Option 2: 230/27.6kV with one 50/83 MVA transformer and 8 feeders
Cost: say $16M
- Option 3: 230/27.6kV DESN with 25/41 MVA transformers and 4 feeders
Cost: say $19M
- Option 4: 230/27.6kV DESN with 50/83 MVA transformers and 8 feeders
Cost: say $21M

7.0 Jac indicated that the City and his Board wanted to pursue an aggressive economic development strategy to attract industry to the area. The city has property in the vicinity of the industrial area and near transmission lines. It would consider holding land in reserve for a new TS but needed to know the size of a "footprint" required. The plan would be for a 230kv tap to a 50/83 DESN. Maps of the possible location were provided to Cliff for review.

ACTION: Alex to provide example dimension requirements. Cliff to review location.

10.TS Budget Quotes 2009

	Vendor A	Vendor B
Deposit on Land Purchase	$25,000	$25,000
Pay Hydro One for Class B Estimate	$120,000	$120,000
Legal and Regulatory Fees	$10,000	$10,000
Total for 2010	$155,000	$155,000
Complete Land Purchase	$875,000	$875,000
Environmental Assessment	$60,000	$60,000
Preliminary Engineering	$588,406	$195,750
FHI Engineering [1]	$80,000	$80,000
Deposit on Transformer (25%)	$494,201	$396,750
Legal and Regulatory Fees	$25,000	$25,000
Total for 2011	$2,122,607	$1,632,500
Engineering & Project Management	$588,406	$195,750
FHI Engineering	$160,000	$160,000
Site Preparation	$200,000	$200,000
Civil Work (foundations, fence etc)	$1,049,904	$2,069,008
Progress Payment on Transformer (50%)	$988,403	$793,500
Deposit on Structural Steel (50%)	$378,019	$102,000
Deposit on Switchgear (25%)	$97,550	$78,631
Legal and Regulatory Fees	$25,000	$25,000
Total for 2012	$3,487,280	$3,623,889
Engineering & Project Management	$588,406	$195,750
FHI Engineering	$160,000	$160,000
Final Payment on Transformer (25%)	$494,201	$396,750
Install All Equipment	$1,813,062	$2,382,771
Install Feeders - FHI	$300,000	$300,000
Install Metering for Feeders	$120,000	$120,000
Station Commissioning and Testing	$190,314	$228,000
Legal and Regulatory Fees	$40,000	$40,000
Total for 2013	$3,705,983	$3,823,271
Contingency (address deficiencies)	$150,000	$150,000
FHI Engineering	$80,000	$80,000
Total for 2014	$230,000	$230,000
Grand Total	$9,700,871	$9,464,660
FHI Direct Costs	$2,080,000	$2,080,000
Contractor Costs	$7,620,871	$7,384,660

11. FHI Board Report TS Decision Oct 2010

MEMORANDUM

October 1, 2010

To: Chair MacDougald & Board Members

From: J. P. Vanderbaan, Vice-President, Engineering and Operations
D. Reece, Secretary Treasurer
K. McCann, Financial & Regulatory Analyst

Re: Second Transformer Station for Stratford – Ownership Recommendation

As previously reported, the existing Transformer Station in Stratford is reaching capacity, and the new data centre load plus projected load growth will put the station beyond the recommended rating (LTR). We have reviewed capacity options with Hydro One, and the most prudent option is to construct a second TS to supply the load growth in Stratford. The new TS would be a DESN (dual element spot network) design with an initial install of one transformer and 4 feeders with the space to install a second transformer and 4 additional feeders.

For the construction of the new TS, there are three options available to us:

1. Hydro One designs, builds, owns, and maintains the new TS (as they currently do with the existing stations in Stratford and St Marys).
2. Festival Hydro designs and builds the station (to meet Hydro One specifications) then turns the asset over to Hydro One who will then assume ownership and maintenance obligations. (This option has never been pursued to date.)
3. Festival Hydro designs, builds, owns, and maintains the new TS.

The second option has not been pursued to date primarily due to technical challenges constructing a station to meet Hydro One's requirements without having them fully involved in the design and installation process (overall minimal cost savings). Therefore, only options 1 and 3 were examined in greater depth.

FHI entered into an agreement with Hydro One for them to prepare a Class B estimate for the station cost. The cost to prepare the Class B estimate is $120,000, which is rolled into the total station cost if Hydro One builds the station, or becomes payable by FHI in 2010 if FHI builds the station. The Class B estimate was received in June with subsequent meetings with Hydro One in July and August to clarify some of the financial information.

The estimated cost for Hydro One to build the station is $17.3M plus an additional $1M for the 230 kV connection, plus the cost of land (including environmental assessment) which is estimated to be around $1M.

In addition to preparing the cost estimate, Hydro One provided a projection of the capital contribution from FHI required based on three load forecasts (low, medium, and high). The incremental revenue associated with the new load is used to offset the capital and OM&A

costs. For the low load forecast, a contribution of $16.3M would be required, for the medium load forecast, a contribution of $13.8M would be required, and for the high load forecast, a contribution of $11.7M would be required. A similar process was done for the 230 kV line connection cost, and the contribution required would be $162,000 for the low load forecast and $0 for the medium and high load forecast. The cost for the land of $1M is over and above the capital contribution amounts.

The Class B estimate from Hydro One included documentation of the preliminary design outlining major components, costing, and cash flow. This information was used to generate an RFQ which was issued to three vendors who had recent experience constructing similar stations in Ontario. Two of the vendors [redacted] both provided pricing at the $8M mark, with the third [redacted] coming in unreasonably low at $4M so we have excluded that price from the analysis. (Note: The RFQ was issued to obtain pricing only, and not to award a turn-key project to a vendor. Any contracts needed going forward will follow the normal FHI RFP process including Board approval as required.)

Costing for station monitoring, routine maintenance, unplanned repairs, and other operating expenses were also obtained by contacting vendors and other utilities that own transformer stations. Generally, O&M costs are minimal during the first ten years, then increasing as equipment ages. A 25 year forecast of OM&A costs (including property tax and insurance) was prepared. (For the Hydro One build and own option, the forecast of their OM&A costs is included in the capital contribution calculation.)

Using the load forecast, capital cost, and OM&A costs, a financial model was created to evaluate the overall impact of the Hydro One build and own option (with FHI providing a large capital contribution) to the FHI build and own option.

A summary of the financial impact is summarized below.

Net Present Value Calculation Comparing the Option 1 & 3

Two tables have been attached to this write-up that highlight the cash flows expected under the options to have Hydro One build, own, and maintain the TS or to build, own and maintain the TS ourselves. The attachments indicate that the NPV of the future expected cash flows for FHI to build the TS ourselves ($4,435,297) would be more beneficial versus having Hydro One build it ($4,855,798).

Impact on Distribution Rates

Festival Hydro's next cost of service rate application will be filed effective May 1, 2014 and FHI has received verbal confirmation from Scott Stoll that this is the best strategy in relation to timing of the rate application and inclusion of the TS in rates. Assuming the new TS is in-service by mid-2013, the full net book value of the TS asset should be eligible to be included in our 2014 rate base.

To determine the impact the new TS would have on existing rates, Festival Hydro updated the 2010 rate model overlaying the impact of the new TS station with its related revenues and costs *(assuming Festival Hydro would build and own; not Hydro One.)* Overall, we would expect distribution rates to increase by 12.5%. Offsetting this increase would be a reduction of $355,000 in Network Connection charges, resulting in a net distribution rate impact of 9.0%.

The table below illustrates the impact to our 2010 rate model. The $9.4 million increased rate base would allow an increase of $305,000 for deemed interest and $369,000 for deemed ROE for a total of $675,000. Since the project is being fully funded by a $9.7 million loan, $528,000 of this amount would be required to fund the interest on the loan.

The table also shows the total bill impact to an 800 kWh residential customer. The TS would cause an overall bill increase of 3.8% over the 2009 distribution rates, compared to a 1.2% on the actual 2010 rate increase.

TS Station - Impact on Rates

2010 Original Revenue Requirement			$	10,288,194
2010 Rate Base:	Before TS	After TS		
Average Assets	40,127,578	49,506,238		
Deemed Interest (60% @5.44%)	1,310,088	1,615,686		305,598
Deemed ROE (40% @9.85%)	1,581,026	1,950,546		369,520
	2,891,114	3,566,232		
Additional O& M costs				234,434
Additional depreciation				214,115
Additional income taxes				158,278
Revised 2010 Revenue Requirement			$	11,570,139
Increase in Revenue requirement				1,281,945
% increase in distribution rates				12.5%
Offset from reduced Network connection charges			$	(354,948)
Revised distribution rate increase******				9.0%

Note: the network charge is a separte charge on the bill, so the distribution charge will in fact go up by 12.5% and the network charge will decline. The above illustrates the impact if all this change went through the distribution charge.

Impact on 800 kW residential customer (total bill):

May 1, 2009 Total Bill	101.18	
May 1, 2010 Total Bill	102.35	
Increase effective May 1, 2010	1.17	1.2%
May 1, 2009 Total Bill	101.18	
May 1, 2010 Total Bill with TS impact	104.99	
Increase with TS impact	3.81	3.8%

Overall, the least impact to our customers is the Festival Hydro build and own option. Additionally, by controlling the design and build of the station, FHI can have better cost containment and schedule the installation of feeders to coincide with load requirements. To ensure this project proceeds smoothly, the costing of the FHI option includes the hire of a full-time engineer starting July 1, 2011 and migrating into a new role in 2014 as part of the overall company succession plan.

Recommendation:
Festival Hydro builds and owns the new transformer station with a projected in-service date for the new station to be targeted for July 1, 2013. The project will commence with an agreement with the City for the purchase of the required property so that the environmental assessment and soil testing can commence in early 2011, and FHI will complete the payment to Hydro One before December 31, 2010 for the preparation of the Class B estimate. Future milestones involving purchases above $30,000 (such as completing the land purchase, hiring consultants and contractors, ordering major components, hiring a new engineer, etc.) will follow the normal Board approval process.

12. Festival Hydro Final Report on TS Supply Options Final Version

Municipal Transformer Station #1

Conceptual Design & Planning Review

Prepared for:

Festival Hydro Inc.

Prepared by

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August 2011

PRIVATE INFORMATION

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Prepared by: ____

Stephen Costello

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1 Executive Summary

Costello Associates Inc. has been retained by Festival Hydro Inc. to assist with the conceptual design and planning review of a proposed new municipal transformer station (MTS). The scope of this work includes the review of the Festival Hydro staff load forecast and planning study, review of the interconnection of the new MTS station, and conceptual design of the station. During the early stages of our work, our scope was expanded to develop a detailed project budget, and to assist Festival Hydro in the selection of a project engineering firm.

The City of Stratford is currently supplied only by the existing Hydro One "Stratford TS". This station is currently operating beyond its published capacity at times of peak annual demand, and relief is required to accommodate any new load growth.

A major new load (xxx) is being constructed in the south end of Stratford, with load projections ultimately reaching 20 MW. In addition, there is a 50 acre industrial subdivision being developed close by which is anticipated to bring another 5MW (or more) load. Further, there are seven (7) existing industrial plants that are either at idle or operating at reduced capacity. It is anticipated that some or all of this load will eventually return to the distribution grid. None of this new or returning capacity can be reliably accommodated on the Festival Hydro distribution system without new transformer station capacity.

Festival Hydro staff prepared a detailed load forecast and long term planning study in 2010. We have reviewed the forecast and believe that the approach to the study is reasonable and consistent with typical LDC planning practices. Staff developed three load growth scenarios, and in all three cases, new transformer station capacity is required. The recommended capacity of the proposed MTS station is based on the highest case of load growth, coupled with the lowest case of development of distributed generation and conservation and demand management activities.

We reviewed the station configuration alternatives that were studied by staff in 2010, and have recommended significant changes to the station design. The preliminary design considered in 2010 was based on a single-ended (one transformer) design. This is not typical for Hydro One or municipal LDC's, and inherently less reliable due to momentary transmission outages during storms. This also provides challenges for routine maintenance, as it is difficult to remove a single transformer from service.

We have recommended that Festival Hydro install a fully-redundant DESN (dual element spot network) design which is commonplace in Ontario. While this approach is more costly than a single-ended station, it provides the same or better level of reliability and redundancy as the nearby Hydro One "Stratford TS", and is consistent with good utility practice in Ontario.

A detailed project budget was developed for the DESN indoor station design. We developed preliminary technical specifications and solicited budgetary pricing from engineering firms, major equipment manufacturers and high voltage contractors. The suggested preliminary budget for this project is $13M, which includes a 10% contingency for minor unforeseen works. A detailed budget should be developed immediately following detailed engineering.

Finally, we assisted Festival Hydro with the provision of an engineering services RFP specification that was used to evaluate and select a professional engineering firm that would perform the detailed engineering for the entire project.

2 Transformer Stations – Background Information

2.1 Role of a Transformer Station

The role of a transformer station (TS) within the overall power grid is illustrated in Figure 1. Electricity is generated at nuclear, hydroelectric, fossil fuel, wind, and other facilities throughout Ontario. Bulk power is routed over long distances via the transmission system at high voltages (i.e. 115, 230, and 500 kV). Transformer stations are used to step the voltage down from the transmission system to the distribution voltage level. There are presently over 300 transformer stations owned by both Hydro One and municipal utilities throughout Ontario.

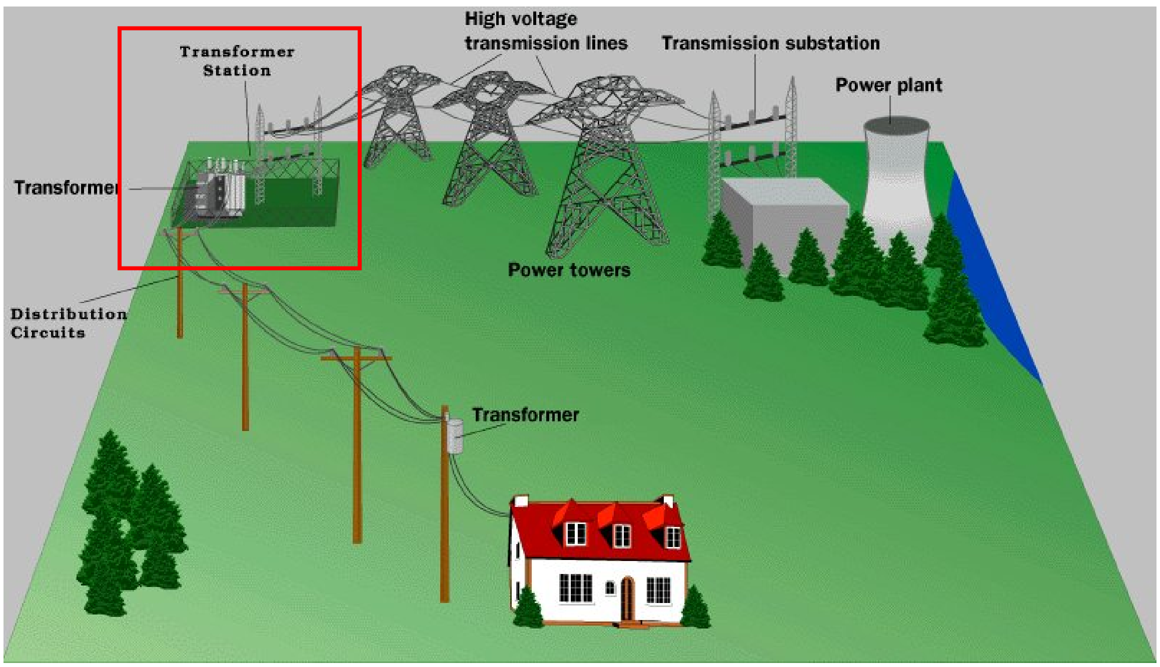


Figure 1

2.2 Transformer Station Ratings

Transformer stations in Ontario are generally designed to have redundancy in critical components, so that the single failure of one device will not result in a loss of supply for distribution customers. Transformer stations are usually supplied by two transmission lines, allowing for constant electricity supply during events such as weather-related momentary outages, and planned maintenance. Stations are equipped with two power transformers, two incoming high voltage switches, two main circuit breakers on the low voltage switchgear, and duplicate protection systems.

As part of the redundancy strategy, power transformers are designed to be overloaded for a specified duration in the event of the failure of one incoming transmission circuits or the failure of the other transformer in the same station. The magnitude of the permitted overload is based on the original transformer design, which accounts for the anticipated summer and winter loading throughout the life of the station. This "Limited Time Rating (LTR)" is the maximum loading permitted on a transformer station for safe, reliable operation.

In the event of the loss of one transmission line or power transformer, any station load in excess of the LTR must be removed from the station. This can be done by transferring load to an adjacent facility, or rotational load shedding if alternate supply is not available.

As part of normal utility planning processes, the transmission and distribution utilities review the capability of the transformer stations to ensure that adequate supply exists. Given that new transformer stations require about two to three years to plan, design, and construct, the decision to build new station capacity must be made well before the electrical load approaches the ratings of the transformer station.

Figure 2

2.3 Potential Impact of Supply Constraints

The creation of additional transformer station capacity is a lengthy process. As a minimum, the shortest time frame possible from the decision to move forward to the in-service date is approximately two years. Items in this process contributing the most uncertainty to the timeline are land acquisition, environmental assessment and transformer delivery.

Accordingly, appropriate lead time ahead of actual need for supply is required in order to be ready when the load begins to materialize. A planning time of two to three years is necessary to accomplish this.

If load growth were to begin to materialize before additional supply capacity was made available, the existing supply infrastructure would be forced to perform beyond its rated capacity. The resulting impacts to Festival Hydro customers could include low voltage problems during high use periods and in order to prevent excessive overloading of equipment, or in the event of equipment failure, rotational blackouts may be ordered by Hydro One. As well, there would be an inability to deliver supply at the pace of growth, and therefore, a delay effect on growth. Should any of these problems occur, the reliability and customer service indicators for Festival Hydro would be negatively affected.

These undesirable situations can be avoided through commitment to additional supply facilities two to three years in advance of the customer growth. Although an inexact science, load forecasts based on expected community growth are the most critical tool for deciding when to begin.

2.4 LDC Experiences with Overloaded TS's

Historically, Ontario Hydro proactively reviewed transformer station loading, and worked with distribution utilities to add capacity whenever it was required. There have been several instances in the past ten years whereby Hydro One transformer stations have been operating well over published LTR ratings. In at least two cases, this has led to critical problems for distribution utilities:

August 2001 – Norfolk TS, Simcoe ON: a high voltage bushing on one of the station power transformers failed, causing the unit to be tripped off. The station had a published LTR of 65 MW, but was loaded to over 95 MW. Hydro One initiated rotational blackouts throughout Norfolk County, which lasted for three days. The failure occurred at the peak of tobacco harvest. See Figure 3 for the Simcoe Reformer newspaper article.

July 1, 2001 – Beamsville TS: the station suffered the failure of one of two power transformers. Beamsville TS had been operating above its published LTR rating. We understand the local fire department was requested to cool the overloaded transformer with water, in an attempt to control the temperature of the transformer. Fortunately, this cooling controlled the internal temperatures and rotating blackouts were not required.

Transformer station failures are rare, but it is important to recognize the potential impacts of operating the station beyond published ratings. Hydro One has the right (and responsibility) to ensure that their transformers are not damaged by overloading, and will therefore take necessary action to keep the load on a given transformer within its LTR in the event of the failure of either its partner transformer or equipment elsewhere on the grid.

Power levels restored in Norfolk

By TREVOR HACHÉ
Reformer staff writer

All's well that ends well.

A lot of people in the area were of that mind after power was fully restored to most of Norfolk County on the weekend following three days of rolling blackouts and brownouts.

The loss of electricity wreaked havoc with alarm systems, computers, telephones, Interac machines, and air conditioners. Half a dozen businesses in Simcoe were forced to close or reduce services to customers.

On Friday, at least two area companies weren't taking a chance using the main power grid. Zehrs on the Queensway and Nexans Magnet Wire, Norfolk Power's largest customer, were using generators to power some of their buildings.

"We thank them for that," said Martin Malinowski, president and CEO of Norfolk Power. "It made more power available to others."

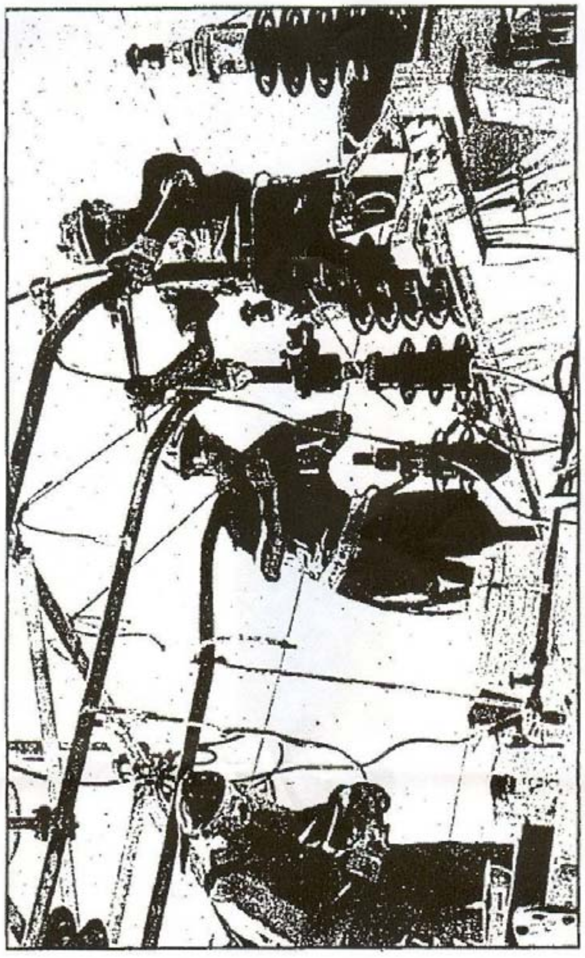
But what caused the transformer that supplies the majority of the county's electricity to fail on Wednesday night remains a mystery.

Karl Peter, a foreman with Hydro One, was at the Norfolk transformer station on Thirteenth St. E. Friday afternoon while crews worked on replacing two damaged bushings.

He said no one has been able to figure out conclusively what caused the initial transformer to fail, sending most of the county's power through a back-up transformer that wavered under the demands of some of the hottest weather in years.

Malinowski originally thought a combination of extreme heat, sunlight, and usage caused a hole to blow in the two bushings. He

(Continued on Page 2)



POWER PLAY: Hydro One station maintenance personnel Dave Rozon (from left), Dan Nagy and Jon Kikot were at the Norfolk transformer station on Thirteenth St. Friday putting the finishing touches on two bushings they had to replace after serious brownout situations plagued the area Wednesday and Thursday. (Staff photo by Trevor Haché)

Power levels

(Continued from Page 1)

then laid the blame on a lightning strike after further investigation.

But Peter said they haven't been able to verify the real reason yet, and may never be able to.

"It's a guessing game. Sometimes they just fail," Peter said.

Peter said the transformers are about 50 years old and at that age they sometimes fail. But he's seen transformers made in the 1930s that are still operating perfectly.

As far as Shirley Robertson is concerned it doesn't matter how old the transformer is as long as it provides her coffee shop with power.

"Everything is fine," said Shirley Robertson, co-owner of two Tim Hortons locations in town. "The air conditioning is working and everything is back to normal."

Robertson was forced to close her coffee shop on Water St. Thursday when its air conditioner unit wasn't getting enough power to operate effectively.

She was able to open her store again Friday.

On that day, Hydro One workers took pressure off the Simcoe transformers by rerouting electricity through stations in Brant County and Jarvis. By Saturday afternoon, the downed transformer was up and fully operational.

As electricity was switched back to the repaired transformer, the lights went out again briefly on Saturday afternoon.

The back-up transformer had been given a workout and will be examined for repairs sometime in the fall, Malinowski said.

– with files from Daniel Pearce

Figure 3

3 Supply Options

3.1 Historical Practice

Prior to the opening of the electricity market, Ontario Hydro typically constructed new transformer station facilities proactively as demand required. These facilities were provided at no direct cost to the distribution utilities, as station costs were pooled and recovered through regulated transmission charges. Costs for related distribution improvements such as feeder ducts and cables were the responsibility of the LDC. The financial evaluation of projects considered the overall transmission and distribution costs, with each entity responsible for their own portion.

3.2 Transmission System Code

In 2002, as part of the industry changes associated with the passing of the Electricity Act and market opening, the Transmission System Code came into effect and we moved to a “user pay” approach. Costs for projects specifically attributable to one or more customers are recovered as part of the regulated connection process. Connecting customers have the choice to undertake certain contestable work or have Hydro One provide services, at the connecting customer’s cost.

In the case of municipal utilities requiring new transformer station capacity, three basic options exist:

1. Hydro One designs, constructs, and operates the new station. An economic evaluation is performed by Hydro One, whereby the net present value of the future incremental load revenue is compared to the cost of construction, operation, and maintenance cost of the station. If there is a shortfall in load revenue, the LDC pays the difference up front in the form of a capital contribution to Hydro One.

2. The LDC designs and constructs the new station according to Hydro One’s technical standards, and turns the station over to Hydro One prior to energization. Hydro One would reimburse the LDC for “reasonable costs” less the cost to oversee and administer the project. The economic evaluation described in the scenario above is used to calculate cost recovery. This option could be used if the LDC believed it could construct a transformer station exactly the same as Hydro One would, and do it for less cost. To the best of our knowledge, no LDC has exercised this option.

3. The LDC designs, constructs, owns, and operates the new station. The station asset would become part of the LDC distribution asset base, and the LDC would earn the regulated rate of return for the value of the station. Some or all of the capital cost of the project would be offset by a reduction in transmission charges payable to Hydro One.

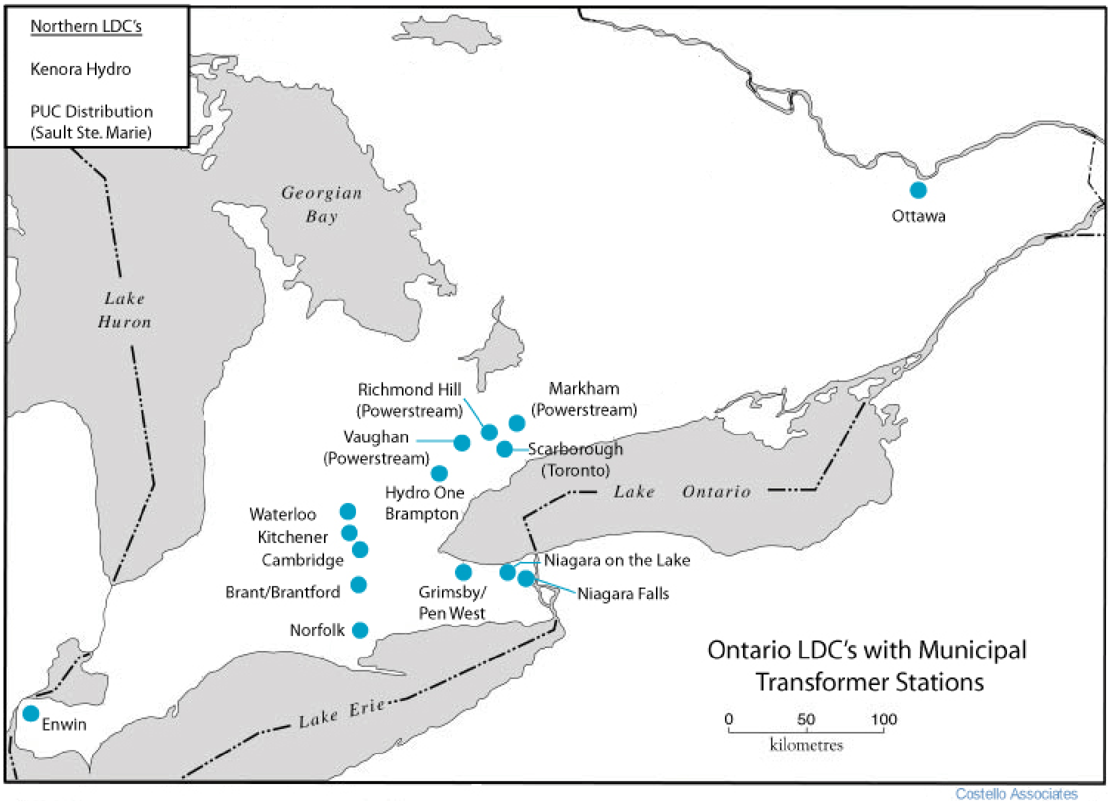


Figure 4

3.3 Comparison of Connection Options

	Principle	Pool-funded Option	LDC Build/ Turn Over to Hydro One	LDC Self-Build Option
1	Overall capital cost	×	◘	✓
2	Risk of load growth – true up payments	×	◘	✓
3	Increase LDC asset base	×	×	✓
4	Control of system capacity	×	×	✓
5	Operating flexibility	◘	◘	✓
6	Lower transmission charges	×	×	✓
7	Lower upfront capital requirements	✓	◘	×
8	Burden on resources – project management, engineering, operating expertise	✓	×	×

Legend: ✓ = Best ◘ = Better × = Least

Table 1

Additional comments on Table 1:

1. LDC's typically build municipal transformer stations for significantly less cost than Hydro One. Historically LDC cost savings were in the range of 20 – 30%, however with recent pricing from Hydro One, the savings are even greater.
2. Should the LDC load not materialize as fast as forecasted, Hydro One could collect additional payments from the connecting customer. If the LDC owned the transformer station, cost is recovered in the distribution rate base, on the book value of the station asset. The amount of load on a municipal transformer station does not affect the recovery of costs and return on equity.
3. Municipal transformer stations are capitalized and placed in the distribution asset base. This provides an opportunity for the LDC to add significant value to the asset base in a single project. This option delivers the highest increase in Shareholder value.
4. The control of system capacity refers to the LDC taking total responsibility for transformer station and distribution system capacity, such that LDC planning ensures that there is sufficient capacity at all times.
5. Operating flexibility refers to day to day system operation, for events such as placing hold-offs, storm response, detailed SCADA information, and maintenance coordination. Hydro One stations are controlled from the Ontario Grid Control Centre (OGCC), and major events across the province are prioritized. A relatively small problem in Festival's service territory may not receive prompt attention from the OGCC if there are larger system issues elsewhere.
6. LDC's that build their own transformer stations avoid the transformation tariff from Hydro One, currently $1.77 / kw. This is a pass through cost via retail transmission charges, but does have an impact on the total end cost to local retail customers.
7. Hydro One pool-funded stations require less up front capital from the LDC as opposed to the LDC building the station. Some capital contribution may be necessary depending on the total capital cost of the project and the value of the incremental load revenue over the 25 year economic horizon.
8. The design and construction of municipal transformer station requires dedicated and experienced resources. Many LDC's do not have internal expertise in stations, its staff may be fully engaged in other activities, or do not wish to take on the responsibility for a project of such magnitude.
9. We are not aware of any connecting customer that has built a transformer station according to Hydro One specifications and turned the station back to Hydro One at time of energization. We expect that although this may seem to be a lower cost alternative compared to Hydro One building the station, Hydro One would impose engineering and administration charges that would be subtracted from the purchase price. We also expect that there would be some growing pains with the development of this process, possibly resulting in delays and higher costs.

4 City of Stratford Growth

4.1 Remaining Capacity

Festival Hydro is the licensed distributor of electricity for the City of Stratford. Festival Hydro receives electrical power from the transmission system, owned and operated by Hydro One Networks. Hydro One Networks owns and operates one transformer station (TS) in Stratford that steps down the transmission voltage to the distribution level. This station is currently operating beyond its rated capacity, and new facilities are required to serve future growth.

4.2 Engineering Load Forecasts

Utility load forecasts can be used for different purposes. Engineering forecasts tend to focus on the capability of the distribution system to provide power to the maximum load that could develop in a given time period. The benefit of this is that should all of the forecasted load actually develop, the infrastructure can accept the new load. In contrast, financial load forecasts are often used for rate-making purposes and may tend to be more conservative. Variations between the actual growth and the forecasted growth can be accommodated in subsequent rate applications. The load forecasts discussed in this report are engineering forecasts, and are based on ensuring that sufficient capacity is available for new growth. Festival Hydro's future rate-making load forecasts may not match the engineering forecasts described below for this reason.

4.3 2010 Long Range Planning Study

4.3.1 New Load Growth

In early 2010, Festival Hydro staff prepared a long planning study for the City of Stratford. The long range load forecast was projected out twenty-five years, which is the length of time mandated by the Transmission System Code for economic evaluations for new transmission investments made by Hydro One.

The study modeled future residential, commercial, and industrial loads, as well as the potential impacts of new distributed generation and CDM measures. Three growth scenarios (low, medium, high) were studied to provide sensitivity analysis for planning decisions.

The potential for residential growth was based on a physical limitation of about 1000 more single family dwellings, and 1000 more high density dwellings. As well, it is anticipated that new lands may be annexed from neighboring jurisdictions that would permit additional residential growth.

Commercial growth was based on historical trends and known development projects such as a university campus and land set aside by the City for commercial development.

Industrial growth was based on three main areas. First, a new data centre is under construction in the southern part of the City. Secondly, the City has developed approximately 50 acres for an industrial park. Finally, there are seven (7) existing factories that are idle or operating at reduced capacity. From a conservative point of view, the study assumed that 50% of this load will resume over the next twenty years.

The long range planning study projects that between 10 and 44 MW of new or returning load will come on to the Festival Hydro distribution system over the next twenty-five years.

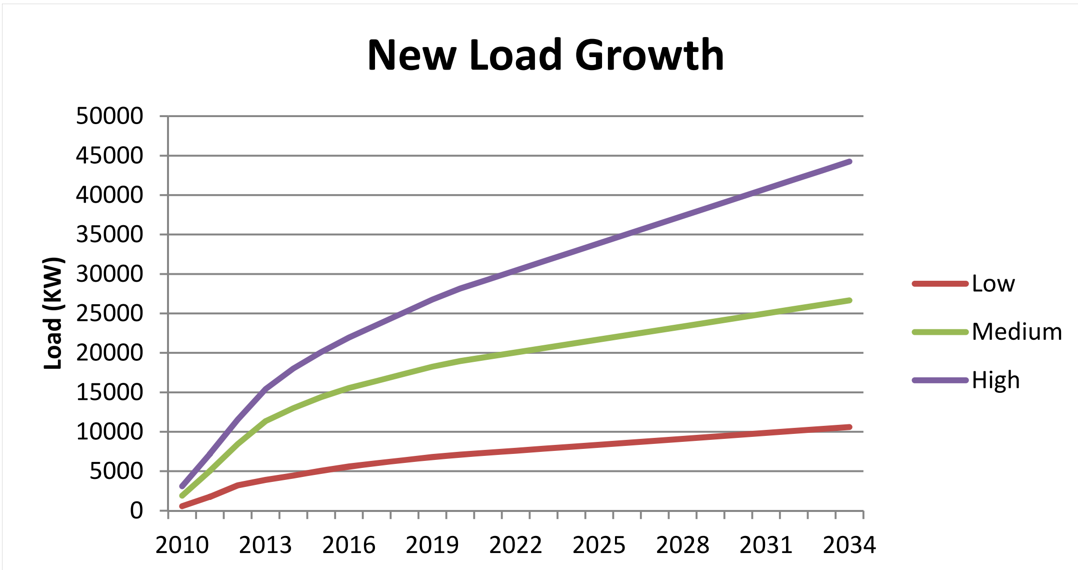


Figure 5

4.3.2 DG and CDM Impacts

The long range planning study provided forecasts on potential development of new distributed generation (DG) and conservation and demand management (CDM) efforts. The study projected that between approximately 3.4 and 18 MW of new generation and demand reduction will be achieved over the next 25 years.

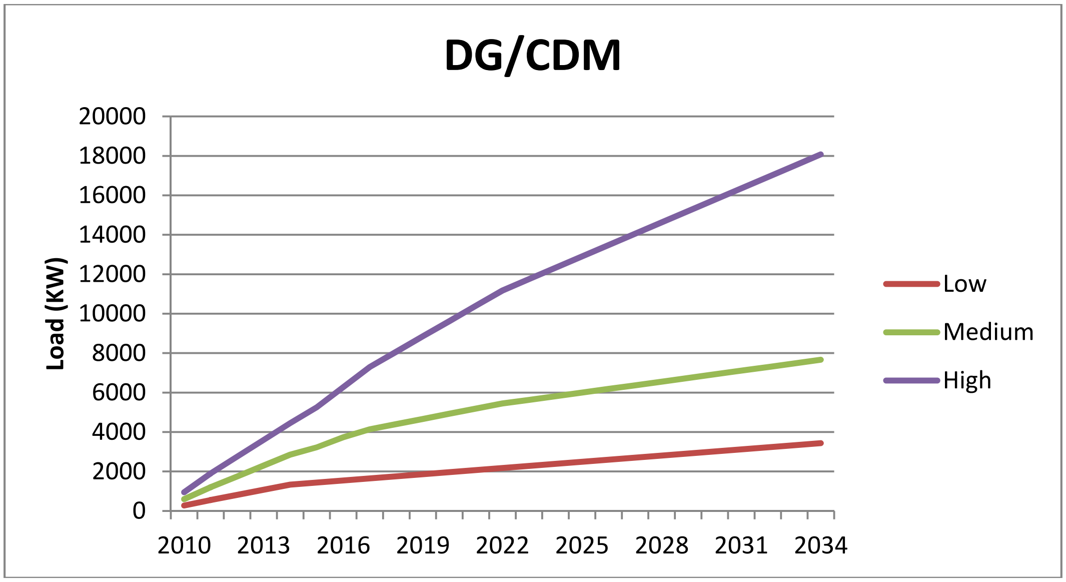


Figure 6

The planning study nets out the new load growth and DG/CDM measures to forecast approximately between 7 and 26 MW of new load that will be required to be supplied from a new transformer station.

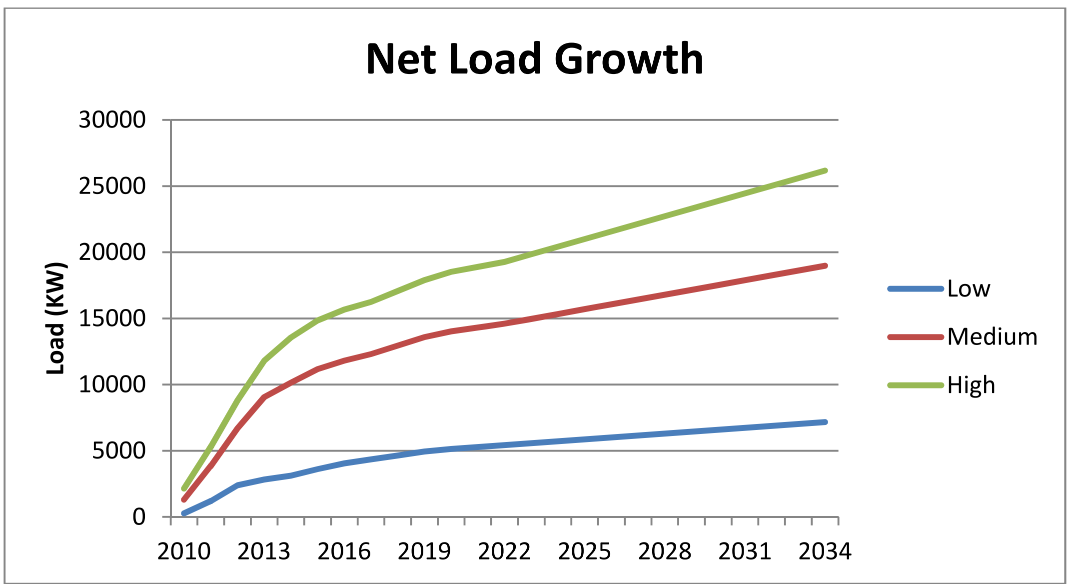


Figure 7

4.3.3 Independent Assessment of Planning Study Methodology

Our assessment is based on the following limitations. We have reviewed the methodology used by staff to forecast load growth, but we have not independently verified the source data. We presume that the source data is accurate and can be supported by Festival Hydro and/or the City of Stratford.

The methodology used by Festival Hydro staff in developing the load range load forecast seems reasonable and is consistent with good utility practice. The modeling of residential loads is fairly straight forward, and is primarily based on the available land for expansion. The modeling methods used for commercial load is fairly conservative as well, and is based primarily on historical trending and physical space for expansion.

Modeling for industrial loads is much more difficult, because there is a wide range of use for available lands that results in significantly different power consumption. The industrial forecast contains significant contribution from the data centre currently under development, as estimates have been provided by the developer. Under the highest load growth scenario, 15 MW of new load is forecasted.

The industrial forecast also contains about 50% of the load from existing idle factories, which have been assumed to come back online within the study period. This seems to be a reasonable assumption.

The load forecast for the 50 acre industrial park was not separately provided, but some utilities use figures of between 75-100 kw/acre as a rough estimate. Using 100 kw/acre, about 5 MW of new load would be expected.

The overall highest-growth scenario in the staff study for industrial load development is 22 MW. It would appear that this is a conservative estimate.

4.3.4 Analysis of Planning Study

As mentioned above in Section 4.2, planning studies relating to supply capacity are geared towards ensuring that there is always adequate supply capacity in the system to allow the distribution system to operate reliably under any routine condition. In addition, the system must have the flexibility to accommodate new loads as they appear so as not to impede local economic development.

In terms of assessing the need for new station capacity, it is abundantly clear that since the existing Stratford TS is already operating above its rated capacity, new station capacity is required to supply *any* new load. Considering the two extreme cases of lowest load development and DG/CDM, and the highest load development without any DG/CDM, there is a range of 7 – 44 MW of potential new load forecasted. Considering that Hydro One anticipates approximately 5 MW of additional load to be developed in their service territory, which would have to be supplied from Stratford TS, there is a requirement for *at least* 11 MW of new load to be placed on a new facility. Clearly a new station is required.

The 25 year load forecast serves two main purposes. First, it allowed Hydro One to provide a cost estimate for a new pool-funded station alternative. For this purpose, the accuracy of the load forecast is very important as there are definite cost implications and financial risks to Festival Hydro. The second purpose is to determine the desired capacity of the new transformer station. The new station should be sized to accommodate the forecasted load growth with some room for unplanned growth.

Festival Hydro provided all three load growth scenarios to Hydro One for economic evaluation of new pool-funded station supply alternatives. Hydro One provided economic analysis for all three cases. Significant capital contributions were required in each case ($10M-14M). We note that in our past experience, Hydro One has not run multiple growth scenarios for our LDC clients. This demonstrates a good deal of cooperation and transparency between Hydro One and Festival Hydro.

Note that there is risk in overstating the load forecast used for these economic evaluations, as the failure to meet the actual load development will result in additional charges from Hydro One down the road. From this perspective, the three growth scenarios provided to Hydro One show that regardless of whether the load grows slowly or more quickly, significant capital contributions must be made to Hydro One.

The determination of the size of the station is often based on the worst-case load growth scenario. Traditionally there are three common sizes of transformer stations used in Ontario by Hydro One and municipal utilities:

1. 25/33.3/41.5 MVA transformers with a summer LTR of about 62 MVA.
2. 50/66.5/83 MVA transformers with a summer LTR of about 125 MVA.
3. 75/100/125 MVA transformers with a summer LTR of about 170 MVA.

The highest load forecast scenario is the maximum forecasted load growth of 44 MW with no DG/CDM influence. If Festival Hydro elected to utilize the traditional station sizes, this would lead to the selection of 25 MVA power transformers with a summer LTR of about 62 MVA. Even if the industrial forecast was a bit conservative, there is still enough capacity to absorb unforeseen load growth.

5 Proposed Municipal Transformer Station

5.1 Overview

Festival Hydro MTS #1 is a proposed 62 MVA (56 MW) municipal transformer station, owned by Festival Hydro. The station will consist of two (20) 25/33.3/41.5 MVA 230-28 kV power transformers, with four (4) 27.6 kV feeder positions. Two additional feeder positions may be required depending on the need for local power factor correction to meet the current IESO market rules. This is discussed in detail later in this report.

We recommend that the station be configured as a dual-element spot network (DESN) system, consistent with design practices of both Hydro One and other Ontario LDC's. This provides complete redundancy of major components and provides continuous supply for failure of any single component.

Single-ended stations (non-DESN) are problematic due to momentary power interruptions caused by auto-reclosing operations of the 230 kV circuit breakers. During storms, these momentary power interruptions will cause all load to be dropped from a single-ended station. This is generally unacceptable to all customer classes, but particularly to industrial customers with critical processes.

A 62 MVA station will provide safe and reliable power to Stratford for the next 25 years, based on current load forecasts using the highest growth scenario.

5.2 Station Arrangement

Transformer stations can be generally classified as either indoor or outdoor stations. In both cases, the 230 kV interrupting devices, power transformers, and primary metering equipment is located outdoors.

Indoor-type stations typically have a switchgear and control building which houses the 27.6 kV switchgear, protection systems, SCADA, and other auxiliary equipment. Feeder cables are buried underground and rise to the overhead distribution system close to the perimeter of the station. Indoor stations are generally more expensive than outdoor stations due to the cost of the building and metalclad switchgear.

Municipal utilities have been utilizing indoor 38 kV class gas insulated switchgear (IEC rated), manufactured in Europe with special features to ensure compatibility with North American standards. This switchgear has a long track record for reliable operation, and is essentially maintenance free. It is also one of the safest designs for personnel with respect to arc flash hazards.

Outdoor stations typically have an outdoor 27.6 kV bus structure, outdoor circuit breakers, and overhead feeders. Outdoor stations are less costly than indoor stations, but are exposed to the elements and animals which tend to reduce reliability and increase maintenance and operating costs.

It is recommended that the Festival Hydro MTS#1 be an indoor-type station, utilizing indoor GIS metalclad switchgear. Indoor GIS stations have been installed by nearly all Ontario LDC's for many years. Indoor stations provide isolation from animal contact and weather, which increases reliability. GIS switchgear is also maintenance free, and very reliable as compared to air insulated metalclad switchgear or outdoor circuit breakers and busses. The switchgear is also arc-resistant by design, and provides superior personnel protection from arc flash hazards than standard metalclad switchgear.

5.3 Conceptual Designs

See Appendix 2 for the following conceptual drawings:

Drawing	Description
C001	Conceptual Single Line Diagram – Indoor Station Design
C002	Conceptual Single Line Diagram – Outdoor Station Design
C003	Conceptual Site Plan – Indoor Station Design 1:200 scale
C004	Conceptual Site Plan – Indoor Station Design 1:500 scale
C005	Conceptual Site Plan – Outdoor Station Design 1:200 scale
C006	Conceptual Site Plan – Outdoor Station Design 1:500 scale

Note that these drawings represent conceptual designs only, and are not approved for construction.

Below are comments specific to each drawing that must be considered during detailed design.

5.3.1 Drawing C001 – Indoor GIS Single Line Diagram

This arrangement utilizes GIS switchgear in a switchgear and control building, and is the preferred alternative.

The budget developed as part of this study includes the cost of all of the major power components shown on this drawing. We note that during detailed design, it may be possible to reduce the ratings of certain components, or provide less expensive means of providing certain functionality. For example, the design utilizes 2500A main and tie breakers. The LTR rating of the power transformers, when translated into current at 28 kV, is just over 1250A – the next lower rating of the same style of breaker. We leave this for review during detailed design.

Also, we propose to feed the station service padmount transformers using a standard feeder circuit breaker. On first glance, this is clearly overkill. Various manufacturers have less costly means of providing such functionality (but not all manufacturers can do this). Again, we leave this issue for detailed design.

Bus PT's are shown as being fed from three position switches. Some vendors are not able to provide this functionality, and therefore the need for such an arrangement must be evaluated and considered prior to awarding a contract for switchgear. We feel that this is an important safety feature, as the EUSA and UWPC safety rules require workers to only work on de-energized (isolated AND grounded) equipment.

Another feature that is NOT shown on the C001 arrangement is end-compartment bus grounding switches. The usual way that IEC provides for bus grounding is through the three position switches associated with the tie breaker. Our utility safety rules require that workers work between grounds. Some utilities have taken the position that additional grounding switches must be provided on the switchgear. Some switchgear vendors can easily accommodate these additional switches, but others can either not accommodate it at all or it is a very expensive upgrade. This must be discussed during detailed design.

5.3.2 Drawing C002 – Outdoor Single Line Diagram

This arrangement is based on a traditional Ontario Hydro "Jones" DESN station design. Electrically it functions very similarly to GIS switchgear, in that there are two incoming breakers, and a tie breaker that couples both busses together.

Advantages for this design include the ability to transfer feeders within the station without involving line crews, ease of visual inspections for problems, and breaker isolating switches for routine maintenance while the station is energized. This arrangement is also less expensive than indoor stations.

Disadvantages include exposure to animals (squirrels, raccoons) that tend to crawl onto energized bushings and insulators, causing flash-over. This causes damage inside the station, as well as produces potentially lengthy outages to distribution customers. The outdoor station is also exposed to weather and wind. This results in higher maintenance and operating costs.

Note that this design provides for manual isolating switches for all circuit breakers, but no "built-in" temporary grounding for maintenance purposes.

Finally, from an esthetics point of view, an outdoor station with overhead feeders may be considered less visually pleasing than an indoor station with buried underground feeders.

5.3.3 Drawing C003/C004 – Site Plan for Indoor GIS Arrangement

Festival Hydro has acquired property for the proposed station, located adjacent to the 230 kV transmission corridor, near the intersection of Packham Road and Wright Blvd. It appears that the site is large enough to accommodate the station with substantial room left over that could be used for other utility purposes.

The conceptual designs for both an indoor and outdoor station are based on locating the station as far back on the site as possible, aligned with the eastern property line. This provides maximum opportunity for visual screening from the front-side of the station, as well as permits the remaining land to the west of the station to be used for other utility purposes. Locating the station in this manner does increase feeder riser costs, but this seems to be a reasonable tradeoff.

The station requires two circuits to be tapped-off the existing right-of-way at either an existing tower or a new tower interspaced between existing towers. It is very costly and time consuming to install a new interspaced tower. If possible, it is preferred to use the existing tower at the northeast corner of the property for this purpose. Hydro One will have to review this arrangement to see if it is acceptable from a clearance and conductor tension point of view.

Other key design factors:

The transformers have been located at least 15m away from the switchgear and control building. We understand that this is the minimum requirement according to the NFPA for fire separation. This must be reviewed by the project engineers/architects during detailed design.

There is a fire/explosion barrier wall installed between the two transformers, in order to ensure that a single event/failure will not impact the healthy side of the station.

The design also includes secondary oil containment for both power transformers. This is not mandated as far as we know, but it is recommended practice and all recent LDC projects have installed similar equipment.

The yard layout includes space for primary metering instrument transformers. An evaluation must be completed during detailed design as to the advantages of primary vs. secondary metering.

Many LDC's are installing backup control centers as part of new MTS stations. The Switchgear and control building includes space for an office and washroom. Both features are costly, and must be evaluated during detailed design.

5.3.4 Drawing C004/C005 – Site Plan for Outdoor Arrangement

The general comments about the property made in Section 5.3.3 are applicable to the outdoor arrangement. Fire separation clearances, explosion walls, transformer oil containment, and the high voltage yard layout is the same for both designs.

The space required for the outdoor yard design is generally the same as for the indoor design with a switchgear and control building. The outdoor design also requires a small prefabricated PCT/SCADA building to house the bulk protection and control systems.

5.4 Description of Major Equipment

5.4.1 Power Transformers

The station will be built comprising of two (2) 25/33/42 MVA, three phase 215.5/28 kV power transformers with a minimum 10 day summer LTR of 62 MVA. The transformers will be configured wye grounded on the high voltage (HV) side and zig-zag grounded on the low voltage (LV) side. The neutral of each transformer will be grounded via 1.5 ohm neutral reactors. Each neutral reactor will have a continuous current rating of 1000 A and a 15 second current rating of 6000 A.

Voltage control of the LV buses is to be provided via a HV under-load tap changer (ULTC) with a range of +/-40 kV in sixteen (16) plus and sixteen (16) minus step positions (33 positions in total).

The transformers shall have secondary spill containment to accommodate 100% of the volume of transformer oil plus accumulated rain and snow. A fire wall shall be constructed between transformers, or sufficient physical clearance shall be provided to prevent damage to an adjacent transformer due to catastrophic failure of one unit.

Transformers are to be designed and constructed to typical local utility standards with respect to short duration overload capability (LTR).

5.4.2 Indoor GIS Switchgear

It is anticipated that the station will utilize 38 kV indoor medium voltage gas insulated switchgear (GIS), designed and built to IEC standards, and certified for use in Ontario by either CSA or the Ontario Electrical Safety Authority. The switchgear shall be of a single-bus design, with two (2) main breakers, four (4) feeder breakers, two (2) station service breakers, and one (1) bus tie breaker.

5.4.3 Protection and Control

A complete PCT/RTU/SCADA substation protection and control system is required to meet the requirements of the Transmission System Code. This system may consist of a station remote terminal unit (RTU), a human machine interface (HMI), protective relays, and intelligent electronic devices (IED's).

The protection components must meet all of the requirements of the IESO and HONI. This typically includes line backup protection, redundant transformer differential protection, transformer sudden gas protection, redundant bus protection, feeder protection, circuit breaker failure protection, syncho-check on main breakers, and redundant transfer trip protection circuits to Hydro One. The control scheme also includes the automatic voltage regulation of the 28 kV busses via the transformer primary tap changers.

Festival Hydro has a Survalent Technology SCADA system that supports DNP 3.0 protocol.

The PCT/RTU/SCADA system will support DNP serial or TCP/IP connections to the following SCADA systems:

- The Owner's Survalent SCADA via DNP 3.0.
- The Owner's contracted after-hours control room service via DNP 3.0.
- The IESO via DNP 3.0.
- Hydro One Networks via DNP 3.0.

Festival Hydro currently has an ICCP SCADA connection between the Survalent SCADA system and the Hydro One NMS system. It is preferred that the new MTS telemetry be provided to Hydro One over the existing ICCP link. A spare DNP port shall be provided on the MTS RTU in case it is required to supply telemetry to Hydro One Networks.

The PCT/RTU/SCADA system shall include the design and specification of any necessary station isolation devices, and assistance with specification, ordering, and testing telecommunication circuits.

5.4.4 Revenue Metering

Primary revenue metering that meets the latest requirements of the market rules as specified by the IESO. Typically LDC's utilize combination PT/CT units manufactured locally in Toronto that are compliant with Industry Canada and the IESO. Festival Hydro's meter service provider (MSP) will be responsible for the coordination of design and approval process with the IESO.

5.4.5 Switchgear and Control Building

It is anticipated that the switchgear and control building can be designed as a general purpose utility structure, without architectural enhancements for aesthetics purposes. The MTS station is located in a proposed industrial subdivision.

The building shall be equipped with a full-height basement for feeder cable egress, separate rooms for switchgear and control equipment, office space, two ventilated battery rooms, washroom, overhead door, and floor door.

5.4.6 Embedded Ground Grid

The station ground grid must be designed in accordance with the latest requirements of the Ontario Electric Safety Code (OESC) Section 36-300, IEEE/ANSI Standard 80-2000, the Transmission System Code (TSC), and Hydro One Networks.

Note that Hydro One currently requires high voltage customer substation ground grids to be designed as “stand-alone” grids without connection to the transmission skywire. In addition, ground grids must be designed to meet the “ultimate” short circuit levels (63 kA or higher).

5.5 Use of Hydro One Transformers

Hydro One has experienced failures and operating issues with a group of some 20+ CGE 75/100/125 MVA power transformers, and is in the process of removing them from service. As we understand it, there was a design or manufacturing issue relating to the leads that connect the windings to the bushings. Apparently under heavy loading conditions, abnormal heating occurred and damage resulted to some of the transformers.

Hydro One has derated the capacity of these transformers and there are currently operating restrictions on numerous transformer stations feeding municipal LDC’s.

Several of these units have catastrophically failed prior to being replaced, such as the failure at Richview TS on Friday March 18, 2011 which caused a major fire that destroyed an adjacent 75/100/125 MVA transformer.

Figure 8

We are aware that Hydro One has offered to sell one of these units to an LDC, but we understand that the transformer will only be used as a spare and will not be used to provide permanent capacity.

We do not recommend that Festival Hydro purchase these transformers from Hydro One, for the following reasons:

1. The size and physical configuration of these transformers is not compatible with the proposed 62 MVA "Jones" DESN-type design. The 75/100/125 MVA units are dual 28 kV secondary, designed to operate in "Bermondsey" configurations.

2. Hydro One is replacing these units apparently because they deem them not to be fit for regular service. The fact that there are known design issues and a track record of failures does not provide confidence that they will operate reliably in Stratford.

3. We are not aware of any plans by Hydro One to deploy these transformers in their own service territory, even with reduced LTR ratings.

5.6 Power Factor Correction

The IESO market rules require that load customers maintain a power factor of no less than 90% lagging or 95% leading, at the point of system interconnection (230 kV side in this case). The market rules do not state if this means that the power factor requirements apply only to peak load conditions or at all times. The IESO has been asked this question many times by LDC's, and we are not aware if they have provided clarification.

Festival Hydro is a summer-peaking utility, and it may be possible that during peak conditions when residential and commercial air conditioning units are running flat out, the system power factor may drop below 90%. Festival Hydro should check their wholesale metering records.

Should the IESO require Festival Hydro to correct the power factor to 90% lagging or better, reactive power compensation, typically static shunt capacitors, must be installed either at the new MTS station or on the distribution system.

Based on the LTR rating of the proposed station, we calculate that at peak conditions, to correct from 85% to 90% power factor, less than 10 MX of reactive compensation is required. This can be provided at the station, but would require at least one feeder position on each bus plus two fixed banks inside the station. The cost of this would be at least $400,000.

We suggest that reactive power compensation, if and when required, be installed on the 27.6 kV distribution system. This provides for voltage support, lowers distribution losses, and is more economical for the small amount of compensation required.

This should be studied in detail by the firm that performs the detailed engineering for the project.

6 Project Budget

6.1 Introduction

We have prepared a detailed project budget for the indoor GIS station alternative. This budget was prepared from two main points of view:

1. Owner-managed – the Owner hires a multi-discipline engineering firm to complete the detailed engineering on behalf of the Owner. The engineering firm creates specifications and tenders for the purchase of major equipment (transformers, switchgear, relay and control, batteries, etc.). The Owner then purchases the major equipment and free-issues to the construction general contractor. The engineering firm also prepares the specification and tender for the general construction contract, and assists the Owner in hiring.

2. Turn Key/EPC – The Owner creates a high level functional specification for the entire station, and issues a tender for engineering, procurement, construction, and commissioning of the facility.

There are advantages to each alternative, but for the purpose of budgeting, we are using the turn-key/EPC pricing for verification of the detailed budget that we have created for the Owner-managed approach.

6.2 Owner-Managed Budget

We prepared preliminary specifications and RFP's for engineering services, supply and installation of major equipment such as power transformers, GIS switchgear, relay and control systems, and general construction contracts. The preliminary specifications and vendor responses are located in Appendices 5 – 7.

The overall budget for this approach is just under $13M, including a 10% contingency for unforeseen works. Note that this is a very high-level budget. A firm budget can only be confirmed after detailed design is completed.

Budget pricing for major equipment and construction is shown below.

6.2.1 Power Transformers

Vendor	Location	Unit Cost	5 Year Warranty	Total	Delivery (weeks)	Total
xxxxxxxxxxxx	xxxxxxxxxxx	$1,180,000	$94,400	$1,274,400	54-58	$2,548,800
xxxxxxxxxxxx	xxxxxxxxxxxx	$870,000	$69,600	$939,600	32	$1,879,200
xxxxxxxxxxxx	xxxxxxxxxxxx	$1,320,000	$105,600	$1,425,600	34-36	$2,851,200

Suggested budget cost: $2,700,000.

6.2.2 GIS Switchgear

Vendor	Location	Unit Cost	5 Year Warranty	Total	Delivery (weeks)
xxxxxxxxxxxx	xxxxxxxxxxxx	$1,191,000	$95,280	$1,286,280	30
xxxxxxxxxxxxx	xxxxxxxxxxxx	$1,012,315	$80,985	$1,093,300	30-32
xxxxxxxxxxxx	xxxxxxxxxxxxx	$895,000	$71,600	$966,600	26

Suggested budget cost: $1,200,000.

6.2.3 Protection and Control

Vendor	Location	Unit Cost	5 Year Warranty	Total	Delivery (weeks)
xxxxxxxxxxxx	xxxxxxxx	$474,400	$39,555	$533,995	N/A
xxxxxxxxxxxx	xxxxxxxxxxxx	$770,000	$33,000	$803,000	N/A

Suggested budget cost: $800,000.

6.2.4 Project Engineering

Vendor	Location	Unit Cost
xxxxxxxxxxxx	xxxxxxxxxxx	$750-900k
xxxxxxxxxxxx	xxxxxxxxxxx	$565,000
xxxxxxxxxxxx	xxxxxxxxxxxx	$650-825k

Suggested budget cost: $800,000.

6.2.5 General Contractors

Vendor	Location	Unit Cost
xxxxxxxxxxxxxxxxxxxxxxx	xxxxxxxxx	$3,702,068
xxxxxxxxxxxxxxxxxxxxxxx	xxxxxxxxx	$5,200,000

Suggested budget cost: $4,500,000.

6.2.6 Budget Summary

1)	**Engineering & Design**					
	2.1) Preliminary engineering		$	50,000		
	2.2) Local Fees and Permits		$	45,000		
	2.3) Soils & Geotechnical Investigations		$	40,000		
	2.4) Detailed engineering & Design		$	800,000		
	2.5) IESO Studies		$	20,000		
	2.6) Hydro One Connection Costs		$	750,000		
					$	**1,705,000**
2)	**Major equipment**					
	3.1) Transformers		$	2,700,000		
	3.2) Switchgear		$	1,200,000		
	3.3) Protection and Control		$	800,000		
	3.4) 230 kV Switches		$	120,000		
	3.5) Grounding Reactors		$	40,000		
	3.6) DC System		$	70,000		
	3.7) Primary Metering		$	300,000		
	3.8) Capacitor Banks		$	-		
	3.9) Feeders and ducts	4 fdrs x 60m x $700/m	$	168,000		
	3.10) Other Equipment		$	750,000		
			.		**$**	**6,148,000**
3)	**Civil Construction**					
	4.1) Mobilization		$	75,000		
	4.2) Site Development		$	170,000		
	4.3) Yard Structures		$	80,000		
	4.4) Switchgear Building		$	950,000		
	4.5) Oil Containment		$	150,000		
	4.6) Concrete Foundations		$	80,000		
	4.7) Fence & Stone		$	110,000		
	4.8) Other		$	750,000		
					$	**2,365,000**
4)	**Electrical**					
	5.1) Grounding		$	225,000		
	5.2) 230 kV Busswork		$	200,000		
	5.3) Station Service		$	200,000		
	5.4) Control Cabling		$	210,000		
	5.5) Cable Pulling and Termination		$	80,000		
	5.8) Commissioning		$	150,000		
	5.9) Bell Canada Construction		$	30,000		
	5.10) Project bonding		$	75,000		
	5.11) Other		$	300,000		
					$	**1,470,000**
	Sub-Total				$	11,688,000
	Contingency 10%				$	1,168,800
	Total				**$**	**12,856,800**

6.3 Turn-key/EPC

We prepared a preliminary turn-key/EPC specification for the complete design, procurement, construction, and commissioning of a new municipal transformer station with the same features as the Owner-managed alternative. We contacted two firms (xxx xxxxxxxx) that had previously supplied budget costs to Festival Hydro, and one other major station construction firm (xxx) .

xxx and xxx submitted pricing for this alternative. xxxx elected to provide costs for an Owner-managed approach only. Vendors submitted detailed proposals, which are included in Appendix 9.

Vendor	Location	Unit Cost
xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx		$11,605,927
xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx		$14,496,721

7. Conclusions and Recommendations

1. Festival Hydro's load forecast and long range planning study is consistent with typical utility practices. The three growth scenarios developed by staff provide a sound contingency analysis for variations in the quantity or timing of new load.

2. New transformer station capacity is required to accommodate any new load growth. A four-feeder station will accommodate all of the forecasted capacity under the highest loading scenario studied.

3. Festival Hydro should design, construct, and operate a new 230 kV DESN-type transformer station, sized to accommodate the highest growth forecast scenario, excluding the influence of DG & CDM initiatives.

4. Festival Hydro should strongly consider an indoor GIS-type of station design. This approach has been commonplace for Ontario LDC's for the past 10 or more years. This provides what we feel is the safest, most reliable, and least operating cost alternative.

5. The purchase of used 75/100/125 MVA transformers from Hydro One is not recommended due to potential design and operating limitations. Several of these units have already failed, and Hydro One is removing them from service. Also, these transformer are not compatible with the proposed station configuration.

6. Festival Hydro should organize the new MTS project in an Owner-administered fashion, hiring an engineering firm directly to complete the detailed design. We do not recommend an EPC-type contract in situations where there are no detailed specifications available to be used as the bases of a contract with an EPC developer.

Appendix 1

Festival Hydro Load Forecast

NET LOAD FORECAST FOR STRATFORD - NEW LOAD LESS DG AND CDM

	LOAD GROWTH - KW PEAK			Cumulative New Load		
	Low	Med	High	Low	Med	High
2010	275	1300	2150	275	1300	2150
2011	925	2550	3150	1200	3850	5300
2012	1190	2850	3500	2390	6700	8800
2013	440	2350	3000	2830	9050	11800
2014	290	1100	1750	3120	10150	13550
2015	490	1025	1300	3610	11175	14850
2016	445	640	825	4055	11815	15675
2017	295	490	575	4350	12305	16250
2018	295	640	825	4645	12945	17075
2019	295	640	825	4940	13585	17900
2020	195	440	625	5135	14025	18525
2021	145	290	375	5280	14315	18900
2022	145	290	375	5425	14605	19275
2023	145	365	575	5570	14970	19850
2024	145	365	575	5715	15335	20425
2025	145	365	575	5860	15700	21000
2026	145	365	575	6005	16065	21575
2027	145	365	575	6150	16430	22150
2028	145	365	575	6295	16795	22725
2029	145	365	575	6440	17160	23300
2030	145	365	575	6585	17525	23875
2031	145	365	575	6730	17890	24450
2032	145	365	575	6875	18255	25025
2033	145	365	575	7020	18620	25600
2034	145	365	575	7165	18985	26175

Total	7165	18985	26175

Included in the above forecast:

	xxx FORECAST - KW PEAK		
	Low	Med	High
2010	0	250	500
2011	0	2000	2500
2012	0	2000	2500
2013	0	2000	2500
2014	0	1000	1500
2015	0	750	1000
2016	0	500	750
2017	0	250	500
2018	0	250	500
2019	0	250	500
Total	0	9250	12750

NEW LOAD FORECAST FOR STRATFORD - IN KW PEAK												
	Residential			**Commercial**			**Industrial**			**Total**		
	Low	**Med**	**High**	**Low**	**Med**	**High**	**Low**	**Med**	**High**	**Low**	**Med**	**High**
2010	200	400	600	250	500	750	100	1000	1750	550	1900	3100
2011	200	400	600	500	750	1000	500	2000	2500	1200	3150	4100
2012	200	400	600	250	500	750	1000	2500	3000	1450	3400	4350
2013	200	400	600	250	500	750	250	2000	2500	700	2900	3850
2014	200	400	600	100	250	500	250	1000	1500	550	1650	2600
2015	200	400	600	100	250	500	300	750	1000	600	1400	2100
2016	200	400	600	100	250	500	250	500	750	550	1150	1850
2017	200	400	600	100	250	500	100	250	500	400	900	1600
2018	200	400	600	100	250	500	100	250	500	400	900	1600
2019	200	400	600	100	250	500	100	250	500	400	900	1600
2020	100	200	400	100	250	500	100	250	500	300	700	1400
2021	100	200	400	50	100	250	100	250	500	250	550	1150
2022	100	200	400	50	100	250	100	250	500	250	550	1150
2023	100	200	400	50	100	250	100	250	500	250	550	1150
2024	100	200	400	50	100	250	100	250	500	250	550	1150
2025	100	200	400	50	100	250	100	250	500	250	550	1150
2026	100	200	400	50	100	250	100	250	500	250	550	1150
2027	100	200	400	50	100	250	100	250	500	250	550	1150
2028	100	200	400	50	100	250	100	250	500	250	550	1150
2029	100	200	400	50	100	250	100	250	500	250	550	1150
2030	100	200	400	50	100	250	100	250	500	250	550	1150
2031	100	200	400	50	100	250	100	250	500	250	550	1150
2032	100	200	400	50	100	250	100	250	500	250	550	1150
2033	100	200	400	50	100	250	100	250	500	250	550	1150
2034	100	200	400	50	100	250	100	250	500	250	550	1150
	3500	7000	12000	2650	5400	10250	4450	14250	22000	10600	26650	44250

Notes:

Residential
Stratford has room for about 1000 more single family dwellings, and 1000 more high density units.
Historically, there have been 100 new single family homes and 100 high density units added per year.
Additional land annexation may occur beyond 2019.

Commerical
Typical commercial growth has been one new medium sized unit per year.
City has plans for development of new commercial in west end, plus in-fill on east end.
Existing vacant land expected to be developed by 2020, with potential for future annexation.
New university campus to be built in 2010 and ready in 2011.

Industrial
New data centre expected to have construction load in 2010, permanent load in 2011 growing to final load in 2015.
City has developed 50 acres of new industrial park, expected to fill in over 25 years.
Approximately 7 existing factories are idle or reduced capacity - expect 50% to resume over next 20 yrs.

FORECAST FOR DG AND CONSERVATION FOR STRATFORD - IN KW PEAK												
	Microfit			**FIT**			**Conservation**			**Total**		
	Low	**Med**	**High**	**Low**	**Med**	**High**	**Low**	**Med**	**High**	**Low**	**Med**	**High**
2010	25	50	100	0	50	100	250	500	750	275	600	950
2011	25	50	100	0	50	100	250	500	750	275	600	950
2012	10	25	50	0	25	50	250	500	750	260	550	850
2013	10	25	50	0	25	50	250	500	750	260	550	850
2014	10	25	50	0	25	50	250	500	750	260	550	850
2015	10	25	50	0	100	250	100	250	500	110	375	800
2016	5	10	25	0	250	500	100	250	500	105	510	1025
2017	5	10	25	0	250	500	100	150	500	105	410	1025
2018	5	10	25	0	100	250	100	150	500	105	260	775
2019	5	10	25	0	100	250	100	150	500	105	260	775
2020	5	10	25	0	100	250	100	150	500	105	260	775
2021	5	10	25	0	100	250	100	150	500	105	260	775
2022	5	10	25	0	100	250	100	150	500	105	260	775
2023	5	10	25	0	25	50	100	150	500	105	185	575
2024	5	10	25	0	25	50	100	150	500	105	185	575
2025	5	10	25	0	25	50	100	150	500	105	185	575
2026	5	10	25	0	25	50	100	150	500	105	185	575
2027	5	10	25	0	25	50	100	150	500	105	185	575
2028	5	10	25	0	25	50	100	150	500	105	185	575
2029	5	10	25	0	25	50	100	150	500	105	185	575
2030	5	10	25	0	25	50	100	150	500	105	185	575
2031	5	10	25	0	25	50	100	150	500	105	185	575
2032	5	10	25	0	25	50	100	150	500	105	185	575
2033	5	10	25	0	25	50	100	150	500	105	185	575
2034	5	10	25	0	25	50	100	150	500	105	185	575
	185	390	875	0	1575	3450	3250	5700	13750	3435	7665	18075

Notes:

MicroFit Initial wave of applications accounted for in 2010 and 2011. Second wave expected to be 50% of first wave.

FIT Stratford is in transmission constrained zone, so limited to 500 kW max per install, only 1 application to date.
Few expected until Bruce to Milton line done in 2014.

Conservation Med amount is FHI estimated target by OEB for peak.

Appendix 2

Conceptual Design Drawings

Appendix 3

Engineering Services RFP

Appendix 4

Owner-Managed Project Budget

Appendix 5

Transformers – Budget Data

Appendix 6

Switchgear – Budget Data

Appendix 7

Protection and Control – Budget Data

Appendix 8

General Contractors – Budget Data

Appendix 9

EPC – Budget Data

Appendix 10

Engineering Firms – Budget Data

13. FHI Load Forecast 2011

FHI Load Forecast 2011

NET LOAD FORECAST FOR STRATFORD - NEW LOAD LESS DG AND CDM

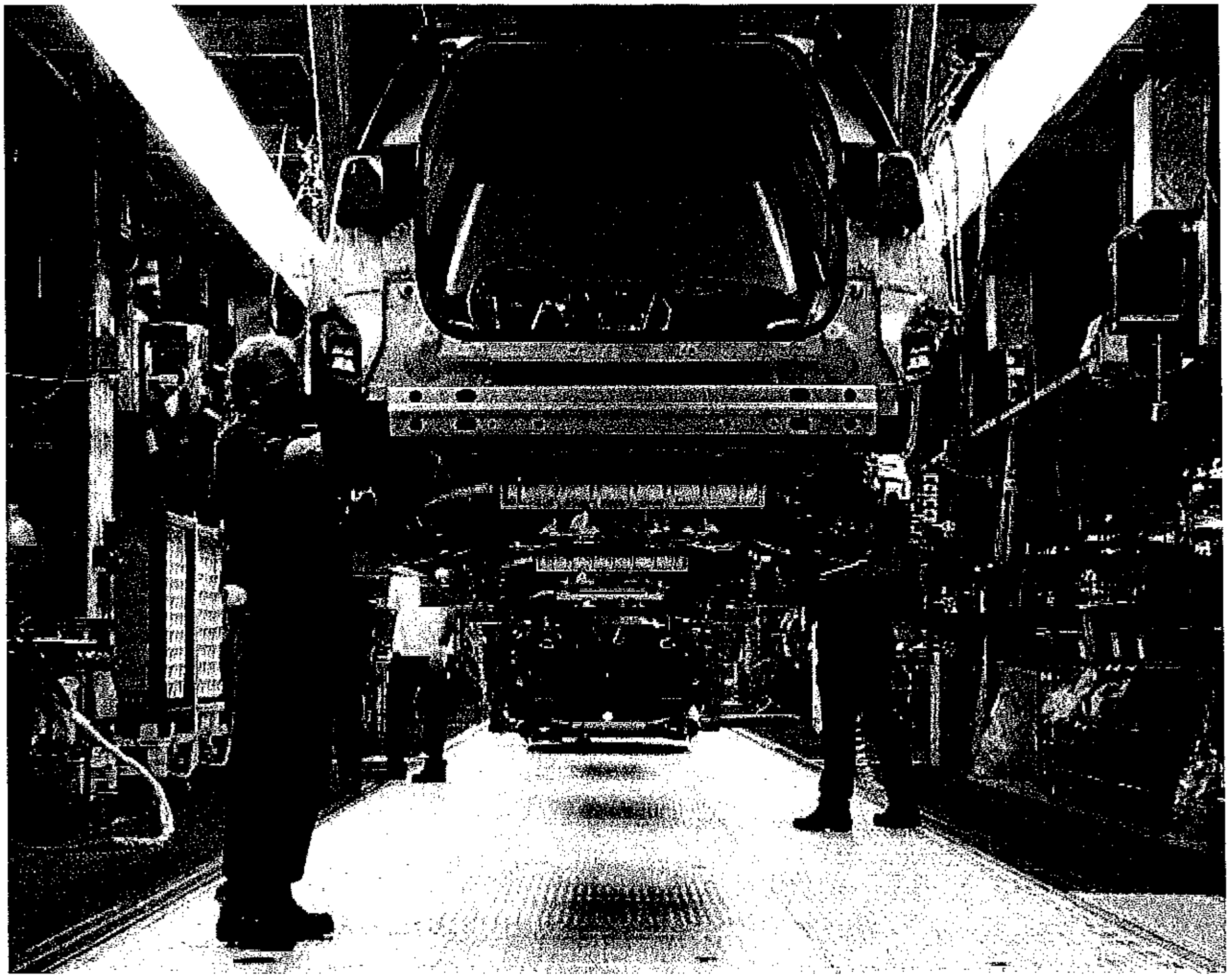
2009 Base 75000 **LTR 85000 (FHI LTR Share)**

	LOAD GROWTH - KW PEAK			Cumulative New Load			Total Load Forecast			Actual	Load Above LTR		
	Low	Med	High	Low	Med	High	Low	Med	High	Load	Low	Med	High
2010	550	1050	1400	550	1050	1400	75550	76050	76400	77000			
2011	1800	3050	3400	2350	4100	4800	77350	79100	79800	80000			
2012	440	1100	3750	2790	5200	8550	77790	80200	83550				
2013	740	1450	3500	3530	6650	12050	78530	81650	87050		0	0	2050
2014	1290	2600	2250	4820	9250	14300	79820	84250	89300		0	0	4300
2015	1440	2775	1800	6260	12025	16100	81260	87025	91100		0	2025	6100
2016	695	1140	1325	6955	13165	17425	81955	88165	92425		0	3165	7425
2017	570	990	1075	7525	14155	18500	82525	89155	93500		0	4155	8500
2018	570	1140	1325	8095	15295	19825	83095	90295	94825		0	5295	9825
2019	570	1140	1325	8665	16435	21150	83665	91435	96150		0	6435	11150
2020	345	690	875	9010	17125	22025	84010	92125	97025		0	7125	12025
2021	295	540	625	9305	17665	22650	84305	92665	97650		0	7665	12650
2022	320	590	825	9625	18255	23475	84625	93255	98475		0	8255	13475
2023	320	665	1025	9945	18920	24500	84945	93920	99500		0	8920	14500
2024	320	665	1025	10265	19585	25525	85265	94585	100525		265	9585	15525
2025	320	665	1025	10585	20250	26550	85585	95250	101550		585	10250	16550
2026	320	665	1025	10905	20915	27575	85905	95915	102575		905	10915	17575
2027	345	690	1175	11250	21605	28750	86250	96605	103750		1250	11605	18750
2028	345	690	1175	11595	22295	29925	86595	97295	104925		1595	12295	19925
2029	345	690	1175	11940	22985	31100	86940	97985	106100		1940	12985	21100
2030	345	690	1175	12285	23675	32275	87285	98675	107275		2285	13675	22275
2031	345	690	1175	12630	24365	33450	87630	99365	108450		2630	14365	23450
2032	345	690	1175	12975	25055	34625	87975	100055	109625		2975	15055	24625
2033	345	690	1175	13320	25745	35800	88320	100745	110800		3320	15745	25800
2034	345	690	1175	13665	26435	36975	88665	101435	111975		3665	16435	26975
2035	345	690	1175	14010	27125	38150	89010	102125	113150		4010	17125	28150
2036	345	690	1175	14355	27815	39325	89355	102815	114325		4355	17815	29325
2037	345	690	1175	14700	28505	40500	89700	103505	115500		4700	18505	30500
Total	14700	28505	40500										

14. Newspaper Clippings

New hybrid could be in Cami's future

By Norman DeBono
Tuesday, August 21, 2012 10:03:14 EDT AM



INGERSOLL - Cami Automotive is driving toward a possible plant expansion and brand new vehicles in 2015.

The Ingersoll automaker is likely to add a hybrid version of its Equinox and Terrain crossover utility vehicles and work has already begun to lay the groundwork for an expansion, likely to be announced next spring, say sources close to the GM Canada manufacturer.

"There is a new vehicle planned for Cami, and it may be a hybrid," one source told The Free Press.

It's too early to say if the new vehicle would significantly boost production or the number of workers. But hybrids have been low-volume sellers so far and the plant is now at full capacity, with about 2,800 employees.

A recent move by GM to get municipal site-plan approval for work at the plant may be a sign of future growth, said Bill Mates, Ingersoll's director of economic development.

"If they are going to all this trouble, it may be," he said. "We are all excited here about the possibility of something happening."

That work may centre around a new, expanded paint and weld facility, said the source.

Expansion isn't a surprise to industry analysts, who say North American vehicle sales will hit about 15 million next year, near pre-recession levels, and all automakers are gearing up to meet demand.

"It is highly likely they will get a variation of a hybrid, the chance of a (Cami) expansion is pretty high," said Kim Korth, president of IRN Inc. in Michigan, which does industry forecasting.

"They will be guarded about this now, because they are in talks with (the Canadian Auto Workers on a new contract), but Cami is making a very popular product."

While the CAW is in talks with GM on a new collective agreement, Cami is delayed and doesn't come up for bargaining until next year.

CAW employees at Cami have also heard rumbles of an expansion and new vehicle, said Bob Scorgie, a CAW committee member at the plant.

"It is hard to know what is true and what is not -- there is a lot of stuff being said," he noted.

"I am sure we are significant players in GM. I hope we get a fair contract for everybody and that there is a plant expansion."

As for the site-plan approval, the automaker is doing the work at the plant to be ready, in case new product comes along, said Faye Roberts, GM Canada's communications director.

"We have done some exploratory work, to make sure we can compete when future allocation decisions are made. But there is no news at this stage," she said.

The work includes taking soil samples, rerouting of power, and waste water treatment, she added.

Cami may not get a full hybrid, but "a form of hybrid technology" using partial electric and gasoline, added Korth.

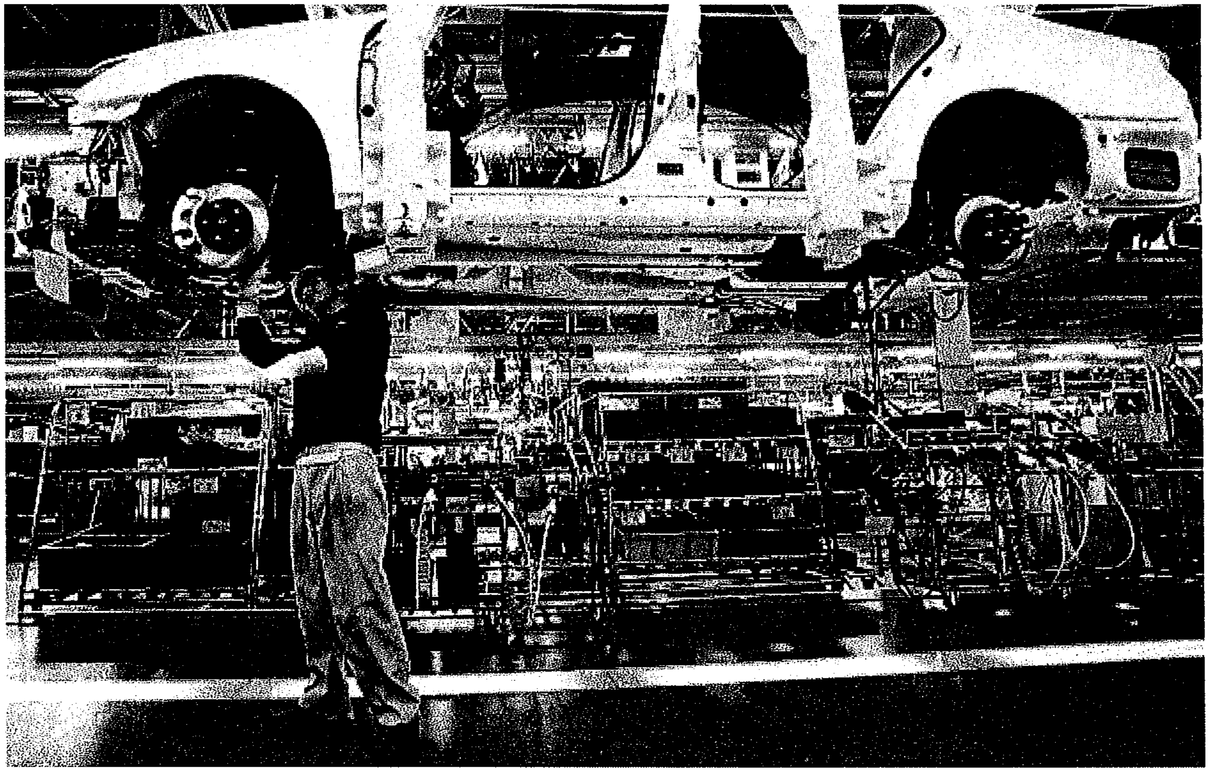
It would be the Canadian auto industry's second hybrid, with Toyota planning to launch a Lexus hybrid sport utility vehicle at its Cambridge plant.

Although GM's Terrain and Equinox are also to be built in Spring Hill Tenn., at GM's former Saturn plant, Korth said she doesn't see Ingersoll losing production to south of the border since "there is more than enough demand to support those plants."

"But (GM) will use it as a bargaining chip, of course, to try get concessions," she said.

Toyota to invest $100 M in Ontario plant, hire 400 workers

THE CANADIAN PRESS JULY 24, 2012



Toyota currently employs some 7,000 Canadians at two plants in Cambridge and one in Woodstock, where the Toyota Corolla, Toyota Matrix, Toyota RAV4, and the Lexus RX 350 vehicles are manufactured.

Photograph by: KEN SHIMIZU, Agence France-Presse via Getty Images file photo

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CAMBRIDGE, Ont. — Toyota's Canadian manufacturing arm says it's investing $100 million in its Cambridge, Ont., plant — a move that will see it hire 400 workers.

The investment will increase the production of the company's Lexus RX models, from 30,000 vehicles to 104,000.

Toyota Motor Manufacturing Canada Inc. says the investment will take its annual production capacity in Canada to 500,000 units.

In March, the company announced it would ramp up production of its RAV4 crossover vehicles at its Woodstock, Ont., assembly plant.

Toyota began its Canadian operations in 1986 in Cambridge.

It currently employs some 7,000 Canadians at two plants in Cambridge and one in Woodstock, where the Toyota Corolla, Toyota Matrix, Toyota RAV4, and the Lexus RX 350 vehicles are manufactured.