ASSET CONDITION STUDY

The Asset Condition Study is included as part of this Exhibit on the following pages as **Appendix F**.

APPENDIX F



DISTRIBUTION ASSET CONDITION ASSESSMENT
FOR
Hydro One Brampton Networks Inc.

Kinectrics Inc. Report No.: K-418001-RA-0001-R00c

Confidential & Proprietary Information
Contents of this report shall not be disclosed
without authority of client.
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DISTRIBUTION ASSET CONDITION ASSESSMENT
FOR
Hydro One Brampton Networks Inc.

Kinectrics Inc. Report No.: K-418001-RA-0001-R00c

Jun 17, 2009

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DISTRIBUTION ASSET CONDITION ASSESSMENT for Hydro One Brampton Networks Inc.

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1 EXECUTIVE SUMMARY

1. EXECUTIVE SUMMARY

1.1 About the Project

Hydro One Brampton Networks Inc. (HOBNI) retained Kinectrics Inc. (Kinectrics) to carry out an Asset Condition Assessment (ACA) of the HOBNI's distribution assets. The assets were divided into 16 Asset Groups listed in section 2.1and, for each of these Asset Groups, ACA included the following tasks:

- Derive Health Indexes.
- Carry out Risk Assessments.
- Conduct Field Surveys.
- Develop optimal capital replacement plan.
- Develop levelized capital replacement plan.
- Provide recommendations for prioritized data gap closure.

In addition, Kinectrics was asked to comment on HOBNI's maintenance practices.

This report summarizes the methodology, demonstrates specific approaches used in this project and presents the resultant findings and recommendations.

1.2 Information Availability and Health Index Methodology Used

The general methodology for Asset Condition Assessment is described in Section 3, while each Asset Group is presented in detail in its own section. The information for each Asset Group includes Health Index, Data Availability Indicator (DAI), Capital Replacement Plans and recommendations for closing data gaps in a prioritized manner.

Where appropriate, the results were modified based on the expert opinion of HOBNI staff. Field observations generally supported the Health Index distribution derived using Kinectrics' methodology. Some differences could be attributed to the fact that the field survey observations weighted all the condition parameters equally while the Health Index formulation used a weighted sum of condition parameters scores.

1.3 Health Index Results Summary

Table 1-1 shows, for each Asset Group, the total number of assets, the percentage of assets in the poor and very poor categories, and the average annual replacement cost for the next 5 years in the levelized capital replacement plan.

The detailed results for each asset are shown from Section 5 through Section 20 of this report.

1 EXECUTIVE SUMMARY

Table 1-1 Health Index Results Summary

Description	Number of Assets	% of Poor and Very Poor	Planned Capital Replacement Cost in first year
MS Transformers	18	50 %	$1.05M
Circuit Breakers	36	8.33%	$63k
Single Phase Pole Mounted Transformers	1544	< 1%	$230k
Three Phase Pole Mounted Transformers	404	< 1%	$240k
Mini-Pad Transformers	11331	< 1%	$784k
Three Phase Pad-Mounted Transformers	723	0%	$240k
Single Phase Submersible Transformers	151	0%	$21k
3 Phase Vault Transformer Banks	1447/3	0%	$560k
3 Phase Load Interrupting Overhead Switches	695	1.15%	$240k
Pad-Mounted Switchgear	286	16.78%	$200k
Wood Poles < 55 ft and Wood Poles ≥ 55 ft	10314	6.64%	$1.05
Primary (Feeder) XLPE Cable	222 three phase circuit-km	19.93%	$3.1M
Primary (Distribution) XLPE Cable	2,246 conductor-km	5.05%	$1.5M
Batteries	151	9.27%	$4k
Utility Chambers	327	15.90%	depends on size and contained assets
Buildings	14	0%	depends on size and contained assets
		Total	$9.26M

1.4 Capital Replacement Plan (CRP)

The Capital Replacement Plan includes two aspects: 1) number of units that are planned to be replaced and 2) the corresponding replacement cost.

The number of units to be replaced was estimated based on either a *proactive* approach, so that they are replaced before failure, or a *reactive* approach based on expected failures and/or re-builds. Replacement cost values for each of the Asset Groups were provided by HOBNI. Table 1-2 shows the average replacement costs used in the analysis and identifies whether a *proactive* or *reactive* approach was used.

Table 1-2 Capital Replacement Plan Summary

Description	Replacement Cost	CRP Approach
MS Transformers	$525k	Proactive
Circuit Breakers	$62.5k	Proactive
Single Phase Pole Mounted Transformers	$4.5k	Reactive
Three Phase Pole Mounted Transformers	$20k	Reactive
Mini-Pad Transformers	$7k	Reactive
Three Phase Pad-Mounted Transformers	$30k	Reactive
Single Phase Submersible Transformers	$7k	Reactive
Vault Transformers	$70k	Reactive
3 Phase Load Interrupting Switches	$60k	Reactive
Pad-Mounted Switchgear	$50k	Reactive
Wood Poles < 55 ft and Wood Poles ≥ 55 ft	$8k	Reactive
Primary (Feeder) XLPE Cable	$350/circuit-meter	Proactive
Primary (Distribution) XLPE Cable	$75/conductor-meter	Proactive
Batteries	$800	Proactive
Utility Chambers	depends on size and contained assets	Repair/Refurbishment
Buildings	depends on size and contained assets	Repair/Refurbishment

1 EXECUTIVE SUMMARY

The Overall Capital Replacement Plan is a total of the replacement projections for all the assets and it is shown in Figure 1-1. Since replacement costs for the assets replaced *reactively* are linked to the probability of failure, the only opportunity to levelize the Capital Replacement Plan envelop is by deferring some of the *proactive* replacements. Figure 1-2 shows the levelized overall Capital Replacement Plan with Station Transformers, and Underground Primary Feeder and Distribution Cable replacements "smoothed out" so as not to significantly increase the risk of failure.

In the legends of Figure 1-1 and Figure 1-2:

(RA) proactive replacement asset group
(FR) reactive replacement asset group

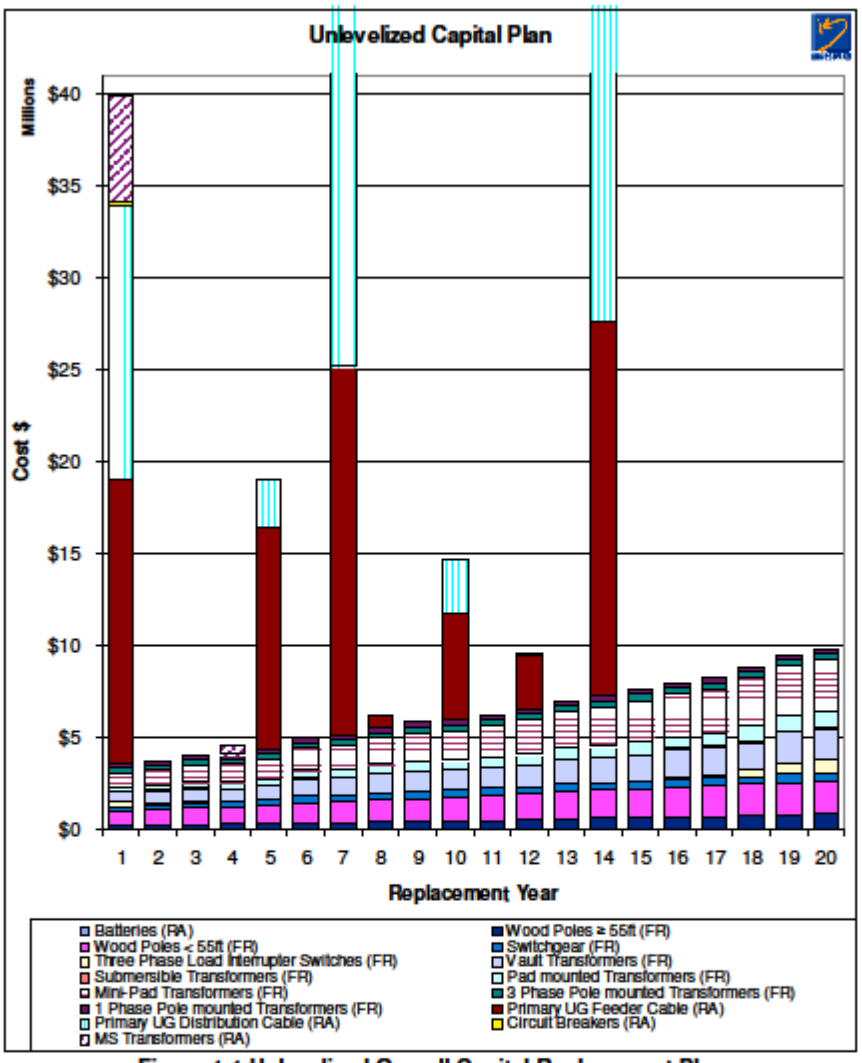


Figure 1-1 Unlevelized Overall Capital Replacement Plan

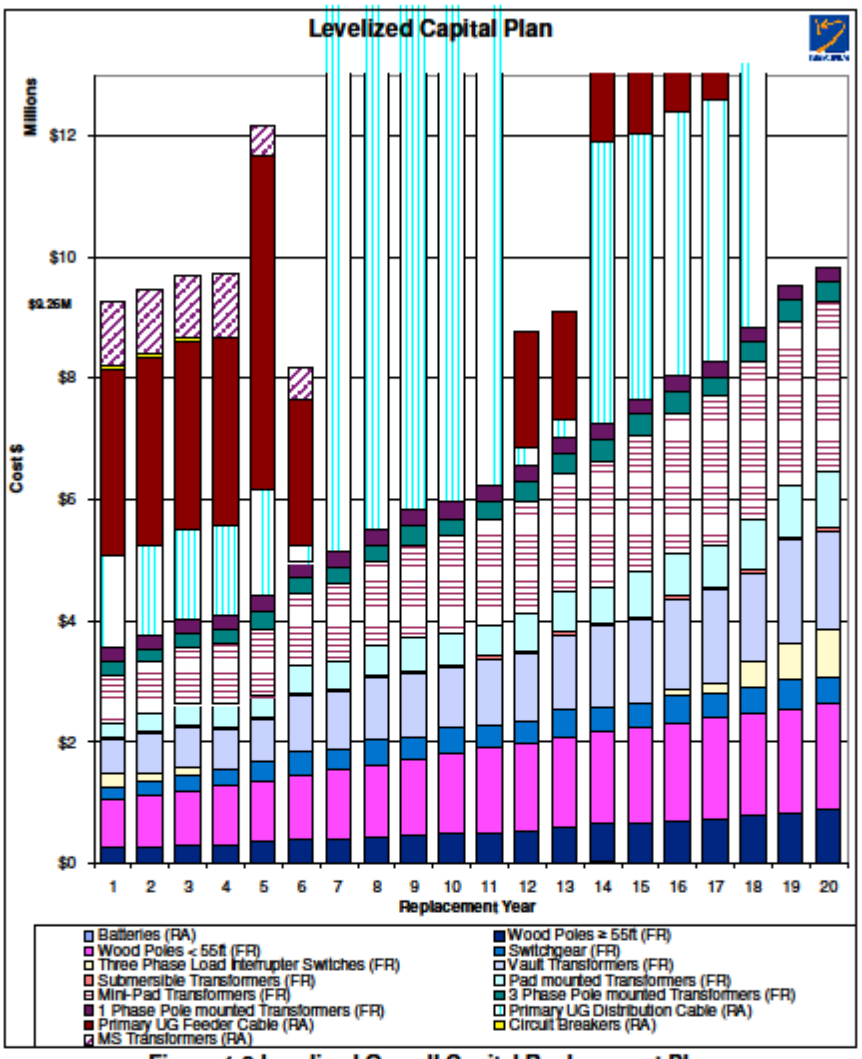


Figure 1-2 Levelized Overall Capital Replacement Plan

1.5 HOBNI Maintenance Practices

The Distribution System Code (DSC) provides guidance on recommended maintenance practices for LDCs. Generally, the requirements are that a distributor shall maintain its distribution system in accordance with:

- Good utility practices.
- More frequent inspections if warranted due to local conditions.
- The use of qualified persons.
- Inspection cycles structured in a manner in which defects are identified during inspection activities and are to be repaired promptly in accordance with good utility practice.
- Address defects discovered within a reasonable period of time.
- Notification to consumers regarding the expected duration and frequency of planned outages.

Hydro One Brampton's practice in this area is compliant with the intent of the Ontario Energy Board (OEB)'s DSC guidelines. HOBNI's inspection and maintenance plan is based on historical data and a solid grasp of priorities in the area of system maintenance.

1.6 Conclusions and Recommendations

1. The availability of condition data collected by HOBNI is compatible with that of comparable size utilities. Prioritized gap closure is recommended, particularly for the following Asset Categories:
   - Power Transformers
   - SF6 and Vacuum breakers
   - XLPE Primary Feeder and Distribution cables
   - Wood poles
   - Utility Chambers
   - Overhead switches
2. There is a need to put in place an overhead conductor testing program that will allow us to determine its condition in various parts of HOBNI's system.
3. The fist year recommended average replacement levelized cost is estimated to be $9.26M with a need to significantly increase underground feeder and distribution primary cable replacement program and double the transformer replacement program.
4. HOBNI's maintenance practices are in compliance with the Distribution System Code (DSC) requirements.
5. Annual data gap closure progress analysis and periodic asset condition assessment are needed to ensure that appropriate investments are being made in replacing aging assets and that adequate condition information is being collected.
6. Collection of measurements for transformer and breakers measurements should start at Jim Yarrow MTS to accumulate required information for the future condition assessments.

2 INTRODUCTION

2. INTRODUCTION

Hydro One Brampton Networks Inc. (HOBNI) is a subsidiary of Hydro One Inc. and is a part of the Hydro One family of companies. It supplies electricity to over 130,000 homes and businesses in the City of Brampton and is regulated by the Ontario Energy Board.

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 90 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and components and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

HOBNI retained the services of Kinectrics to carry out condition assessment of its electrical distribution system assets, estimate the resultant capital replacement requirements and identify condition data gaps.

A considerable portion of this work was devoted to the development of Health Indices based on the information provided by HOBNI, a brief visual field survey conducted by Kinectrics and the expert opinion of HOBNI staff.

This report presents the findings of the HOBNI's distribution assets condition assessment and includes the development of Health Indices for the specified Asset Groups, Risk Assessment based on probability of failure, optimal and levelized capital replacement plans and recommendations on prioritized condition data gaps closure.

2.1 Objective

Kinectrics performed an Asset Condition Assessment of HOBNI's electrical distribution system. The following distribution system assets, referred to as Asset Groups throughout this report, were covered under the scope of work for this project:

- Municipal Station (MS) Transformers
- Circuit Breakers
- Single Phase Pole Mounted Transformers
- Three Phase Pole Mounted Transformers
- Mini-Pad Transformers
- Three Phase Pad-Mounted Transformers
- Submersible Transformers
- Vault Transformers
- Three Phase Load Interrupting Overhead Switches
- Pad-Mounted Switchgear
- Wood Poles < 55 ft and Wood Poles ≥ 55 ft
- Primary (Feeder) XLPE Cable
- Primary (Distribution) XLPE Cable
- Batteries
- Utility Chambers
- Buildings

2.2 Scope of the Work

The project includes the provision of expert support in the following areas:

- Formulation of a Health Index Report on all assets based on the results of the Asset Condition Assessment (ACA).
- Quantitative Risk of Failure Assessment based on the Health Indexes developed.
- Identification of assets to be replaced based on the above Risk of Failure Assessment and taking into account cost of failure consequences.
- Prioritization of assets to be replaced, using cost vs. benefit analysis.
- An optimal capital and, where applicable, levelized plan for assets to be replaced.
- A review of time-based and condition based maintenance practices and recommend improvements.
- Identification of condition data gaps and recommendation for their prioritized closure.

These areas and the factors of assessments covered under this project, are based on Kinectrics experience and familiarity with the industry requirements, and serves well the purposes of this project, namely to support HOBNI's Rate Application to the OEB and to substantiate the rational for the expenditures being sought. As such, the results will help HOBNI in its service rate application submission to the OEB and will provide a basis for a medium to long-term capital plan for its distribution assets.

2.3 Deliverables

The deliverables in this report include the following information:

- Short description of the asset groups being considered in the study
- Discussion of asset degradation and end-of-life issues
- Demographics of the assets being considered
- Assessment of data availability by means of a Data Availability Indicator (DAI)
- Health Index results for the Asset Groups
- Description of methodology for assessment of criticality and consequence of failure
- Risk Assessment results based on quantitative evaluation of consequences of failure
- Number of units recommended for replacement and Optimal Capital Replacement Plan
- Levelized Capital Replacement Plan
- Recommended strategy for closing asset condition data information gaps

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3 ASSET CONDITION ASSESSMENT (ACA) METHODOLOGY

3. ASSET CONDITION ASSESSMENT (ACA) METHODOLOGY

3.1 Determining Health Index

The Health Index quantifies equipment condition by comparing an asset's Condition Parameters with the Condition Criteria that are measures of the long-term degradation that cumulatively lead to an asset's end-of-life. Health Indexing differs from maintenance testing whose objective is finding defects and deficiencies that need correction or remediation in order to keep the asset operating prior to reaching its end of life.

Therefore, when using the Health Indexing method it is important to understand the differences between defect management and the resultant unplanned maintenance versus long-term asset condition assessment that evaluates long-term asset degradation leading to its end-of-life:

- Defects are usually well defined and are due to failed or defective components in the ancillary systems that affect operation and reliability of the asset well before it reaches its end of life. These defects do not normally affect the life of the asset itself, if detected early and corrected. Defects are routinely identified during inspection and dealt with by corrective maintenance activities to ensure continued operation of the asset.

- Long-term degradation is generally less well defined and is not easily determined by routine inspections. The purpose of Asset Condition Assessment is to detect and quantify the extent of long-term degradation and to provide a means of quantifying remaining asset life. This includes identifying assets that are either at or near their end-of-life or are at high risk of generalized failure and will require capital expenditures to either refurbish or replace them.

A good understanding of the asset degradation and failure processes is vital if condition assessment procedures are to be effectively applied. It is important to identify the critical modes of degradation, the nature and consequences of asset failure, and the estimated time remaining until the asset is degraded to the point of unacceptably high failure probability. In order to establish proper assessment criteria and to define appropriate end of life criteria it is essential to have a good understanding of the degradation and failure processes.

A composite Health Index can be used as a tool for assessing the overall health of a complex or relatively simple asset. Distribution assets may consist of several components, e.g. distribution station transformer, or be less complex, e.g. pole mounted transformer. In either case there may be one dominant mode of failure, or there may be several independent failure modes, either for components comprising the asset or for the asset itself. The composite Health Index combines scores indicating the condition of all of these Condition Parameters into a single indicator of the health of the asset.

For a typical asset class, a wide range of diagnostic tests and visual inspections may be undertaken, either as a part of the ongoing maintenance program or as special-purpose Asset Condition Assessment (ACA) surveys. In some cases, a poor condition rating

value will represent an impending, probable failure that can be addressed through replacement of a deteriorated component of the asset, without the need to replace the whole asset. However, it should be recognized that generalized deterioration of many or all of the components that make up an asset can also be a valid indication of the overall health of the asset. In developing a composite Health Index for an asset, it is very important to understand the functionality of the asset, and for the multi-component asset, the manner in which the various components work together to perform the key asset functions. Thus, the Health Index captures generalized deterioration of asset and its components, as well as "fatal" deterioration of a dominant component for multi-component assets. Health Index scores can then be subdivided into ranges of scores that represent varying degrees of asset health.

The critical objectives in the formulation of a composite Health Index are:

- The index should be indicative of the suitability of the asset for continued service and representative of the overall asset health.
- The index should contain objective and verifiable measures of asset condition.
- The index should be understandable and readily interpreted.

Development of a condition-based Health Index requires an assessment of the relative degree of importance of the different Condition Parameters in determining the overall health of the asset. Each Condition Parameter is measured against an established Condition Criteria using available data and must be assessed as falling into one of the four categories shown in Table 3-1.

Table 3-1 Relative Degree of Importance of Condition Parameters

Low Impact Condition Parameter	**Reflects defects or deterioration measure that have no impact on overall asset health e.g. Silica gel in Transformers**
Contributing Condition Parameter	**Reflects defects or deterioration measures that range from low to high in importance, but typically in combination with other measures as part of a formulation of generalized deterioration. e.g. Contacts in Circuit Breakers.**
Combinatorial Condition Parameter	**Reflects a measure which does not represent asset condition in isolation, but is a critical component in a complex logical and/or mathematical formulation of asset health. e.g. Oil Quality Test in Transformers.**
Dominant Condition Parameter	**Reflects the health of dominant subsystem or component that makes up the asset, and end-of-life based on this single factor can represent end-of-life for the entire asset. e.g. DGA Test in Transformers or remaining strength in Wood poles.**

By using a multi-criteria analysis approach, the Condition Parameter Scores for various Condition Parameters are combined into a composite Health Index. This involves establishing Condition Parameter Scores, crafting the mathematical and/or logical formulations, and establishing the importance weightings of all the Condition Parameters to produce a single overall Health Index of the asset.

3 ASSET CONDITION ASSESSMENT (ACA) METHODOLOGY

The general formulas for both Health Index and Condition Parameter Scores (CPS) are shown below:

$$HI = \frac{\sum_{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{\forall m} \alpha_m (CPS_{m,\max} \times WCP_m)}$$

where

$$\text{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n,\max} \times WCPF_n)} \times 4$$

m = Condition parameter m
n = Sub-condition Parameter n
$\forall$ = for all. The values of n and m depend on the asset group and Health Index formulation under consideration.

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Condition Parameter Factor
WCPF = Weight of Condition Parameter Factor

α_m = Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
β_n = Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable).

A quantified scoring system is developed to appropriately represent the asset health consistent with this methodology. This involves the following steps:

1. "Deterioration" assessments for individual Condition Parameters are calculated by Condition Parameter Scores in a defined range from "perfect health" to "end-of-life".

2. Importance weighting (Condition Parameter Weighting) is assigned to each Condition Parameter in a range from "modest importance" to "very high importance" based on the definitions in the Table 3-1.

3. The general deterioration index is formulated by summing the multiples of steps 1 and 2 for each Condition Parameter.

4. The general deterioration index is normalized against the maximum possible score of 100%.

5. The overall Health Index is calculated where 1 or 100% represents excellent condition and 0 or 0% represents "very poor" or end of life condition.

6. The continuum of asset health scores is typically aggregated into five categories of asset health from "Very Poor" to "Very Good".

Normally, with many Condition Parameters included in calculating the Health Index it is seldom less than 0.25, because some of the Condition Parameter Scores usually indicate good condition. To account for this, the interpretation of the Health Index to obtain effective age and probability of failure is based on the premise that a Health Index of 0.25 indicates that the asset is at its end of life.

Because a given asset may not have sufficient data for assessing the condition of all possible Condition Parameters, an additional factor called the Data Availability Indicator or DAI is calculated. The DAI is determined by the ratio of the weighted Condition Parameters Score for the subset of Condition Parameters data available for this asset over the "best" overall weighted, total Condition Parameters Score. The formula is given by:

$$\mathrm{DAI}_{\mathrm{CPS}\,m} = \frac{\sum_{\forall n} \beta_n (CPF_{n\,\max} \times WCPF_n)}{\sum_{\forall n} (CPF_{n\,\max} \times WCPF_n)}$$

$$DAI = \frac{\sum_{\forall m} (\mathrm{DAI}_{\mathrm{CPS}\,m} \times WCP_m)}{\sum_{\forall m} (WCP_m)}$$

where

$\mathrm{DAI}_{\mathrm{CPS}\,m}$	= Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	= Data availability coefficient for condition factor (=1 when data available, =0 when data unavailable)
WCPF_n	= Weight of Condition Parameter Factor n
DAI	= Overall Data Availability Indicator for the m Condition Parameters
WCP_m	= Weight of Condition Parameter n

An asset with all Condition Parameter data represented will, by definition, have a DAI value of 1 or 100%. In this case an asset will have a DAI of 100% regardless of its Health Index score and there is a high degree of confidence that the Health Index score can accurately reflect the asset's condition. If, on the other hand, an asset has a low value of DAI then the confidence level that the Health Index score accurately reflects the asset condition is less and more information would have to be collected to close the data gaps and have more confidence in the Health Index score.

3.2 Qualitative Relation of Health Index to Probability of Failure

The ideal relationship would be to have "Condition" (quantified by the Health Index) be directly related to the failure probability based on experience. For wood poles, for instance, one could say that the Condition or strength at the present time and the rate of loss of strength could be directly related to the end of life of the pole. Unfortunately, there is little empirical evidence for most classes of assets of a direct relation between condition, as indicated by Health Index, and probability of failure and remaining life.

One way of mapping the Very Good, Good, Fair, etc condition categories to probability of failure is illustrated in Figure 3-1 below. The Health Index categories (Very Good, Good, etc) could also be mapped directly to replacement timing as indicated in Table 3-2.

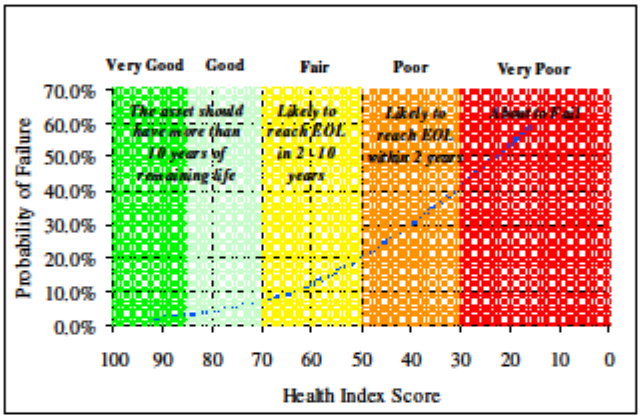


Figure 3-1 Qualitative Estimating of Probability of Failure from the Health Index

Table 3-2 Health Index Scale

Health Index	Condition	Description	Expected Lifetime	Requirements
85 – 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 15 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	More than 10 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 3 – 10 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 3 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

If the Data Availability Indicator is relatively low this qualitative assessment of risk consequences is preferred because not enough information about the condition is known and thus it is not practical to perform a quantitative or asset specific risk assessment.

3.3 Determination of Failure Rates

The failure rate curve for a component is obtained by adapting a standard textbook "bathtub" curve (which is an exponentially increasing failure rate) so that it matches the median life and maximum life that has been observed to occur at a specific utility for certain assets. The form of the failure rate vs. age equation is $P_F = e^{\beta(x-A)}$, where A and B are constant parameters that control the location and steepness of the exponential rise (x is the variable representing age in years). When data is not available then the simple exponential provides the "best" model. If actual failure rate data is available it may be possible to use a more complicated exponential function. In this case, a Weibul distribution is used to model an exponential probability function but can also be adjusted to more accurately fit the data if the function is not quite an exponential form.

If no data for failure rate vs. age is available then the A and B parameters of the failure rate equation can be determined from estimates of the median age of failure and the maximum age based on the utilities experience. It is important to use the experience of a specific utility when it is available since operating conditions, environmental factors, and maintenance practices affect equipment failure rates. Figure 3-2 shows a cumulative failure vs. age curve fitted to a median age at failure of 53 years and a maximum age (defined as 99% of all units failed) of 75 years.

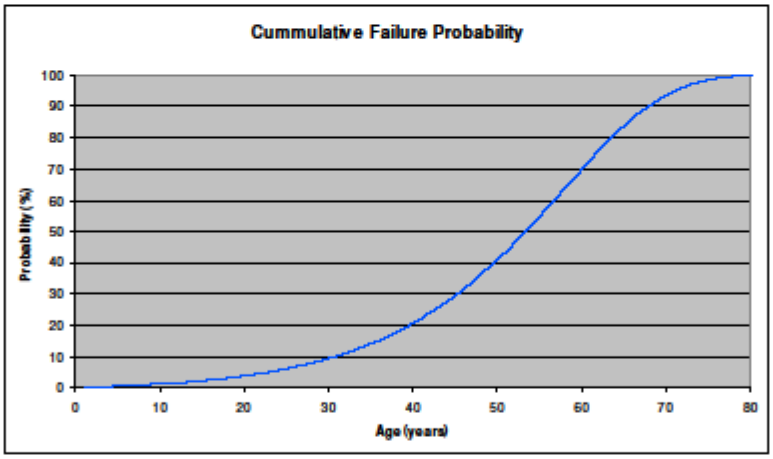


Figure 3-2 Cumulative Failure Probabilities

Figure 3-3 shows the same failure data as annual failure probability.

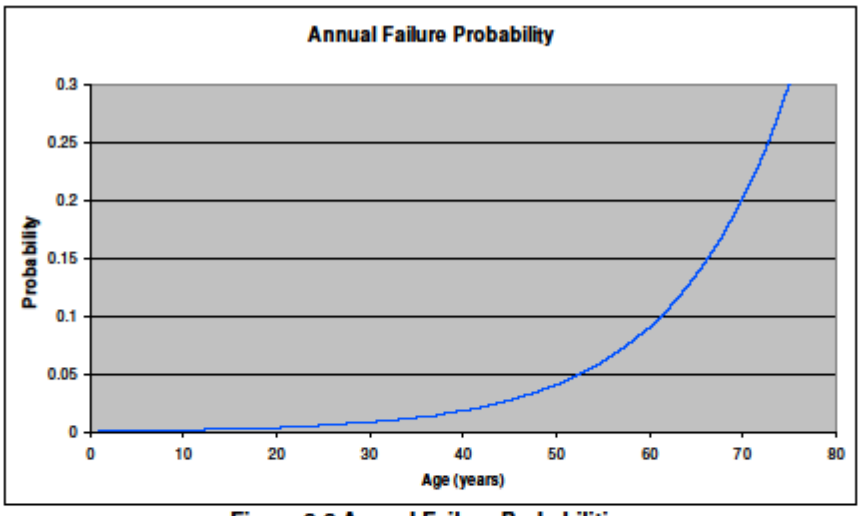


Figure 3-3 Annual Failure Probabilities

3.4 Quantitative Relation of Health Index to Probability of Failure

If the Data Availability Indicator is relatively high and a sufficient amount of data is available, it is necessary to consider how condition and probability of failure are related in order to develop the full relationship between Health Index and probability of failure. Each asset could be considered to have a certain condition or strength. Failures occur when the stress to which an asset is exposed exceeds the asset's strength. Since the stress is not constant and varies around a mean value with a somewhat "normal" frequency distribution, the probability of the stress exceeding the strength leads to the probability of failure.

Figure 3-4 shows the probability density function of stress that an asset experiences. The probability of failure is proportional to the area under the stress probability curve to the right of the line representing asset strength or condition (the dark shaded area), i.e. the area where the stress is larger than the strength.

The normally distributed stress curve leads to a relationship between asset condition and probability of failure which is not linear, i.e. as strength decreases (vertical line moves to the left) the probability of failure increases at a greater rate.

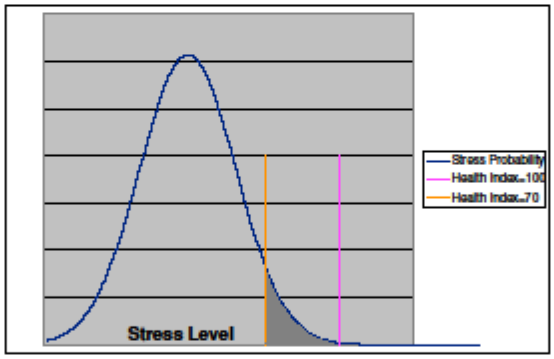


Figure 3-4 Failure Probability Related to Health Index

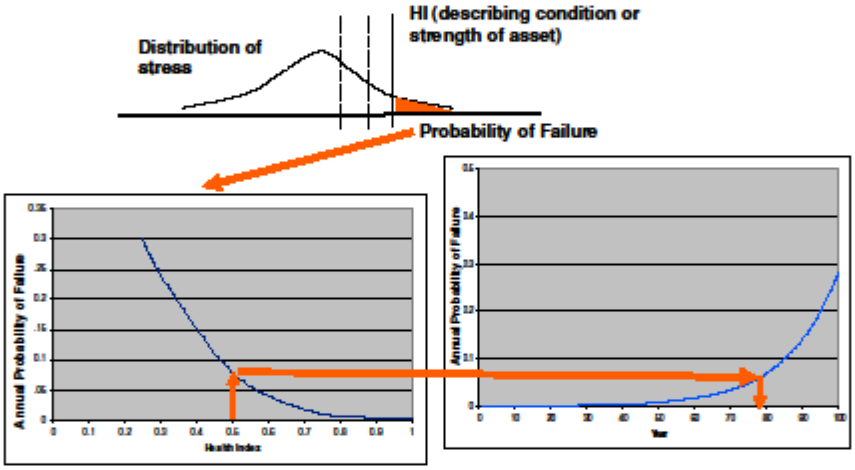
The two points of Health Index and probability of failure (new, Health Index=1 (100%) and at end of life, Health Index=0.25 (25%)) can be used to generate the probability of failure at other Health Index values. Consider the Health Index to represent the "strength" of a component. As the Health Index moves linearly from 1 to 0.25 the vertical line in Figure 3-4 moves linearly to the left. As it moves, the probability of failure at each Health Index is proportional to the area it has passed under the normal curve. This establishes the relationship between Health Index and probability of failure.

3.5 Relating Health Index to Effective Age

The relationship between Health Index and probability of failure can then be used to relate Health Index to "effective" age. The probability of failure associated with a specific Health Index value is determined from the left hand graph of Figure 3-5. The associated probability of failure is then found on the right graph (the failure rate vs. age graph determined previously) and the "effective age" is read off the horizontal axis of the right hand graph.

The Condition derived from the Condition Parameters, when mapped to Probability of Failure, will provide an Effective Age of the Asset.

Probability of Failure includes stress and condition (strength)



HI (Condition), relates to Probability of Failure, which relates to Effective Age

Figure 3-5 Relationship Between Asset Condition and Effective Age

3.6 Repair vs. Replace Decision Risk Analysis

Once the Health Index has been determined for an asset, and the "effective age" has been estimated from it, then the next step is to assess the risks and determine the optimal time for intervention to reduce the risk if action is required. The intervention can be in the form of replacement, refurbishment or increased monitoring.

The risk is assessed by assigning a dollar value to the positive and negative aspects of each alternative date for intervention. The positive effect of delaying intervention is reduction of the actual annual capital cost. For example, if an asset worth $10,000 is

replaced in 10 years its effective annual capital cost, to pay for the asset and the cost of using the capital (assumed to be 6% per year), would be $1360 per year. If the same asset is replaced after 20 years, the annualized cost is $870 per year, etc. The negative effect of delaying intervention is an increasing maintenance cost, and an increasing probability that the costs associated with equipment failure will be incurred. The utility costs associated with failure include the replacement cost of the asset, any collateral damage to adjacent equipment, environmental clean up costs, overtime labour premiums, and the lost revenue (depending on the tariffs structure). Some utilities also include the cost of interruptions to customers.

The expected value of the negative effects of delaying intervention is estimated by multiplying the probability of failure by the costs associated with failure. This number is often referred to as the "risk cost" or "consequence cost". As the intervention is delayed more years, the probability of failure increases and this increases the risk cost.

The method is illustrated in the Figure 3-6. While the annualized capital cost is decreasing with time, the risk cost is increasing. The total cost can be seen to have a minimum point. This is the optimal time to intervene to reduce the risk costs. If the asset is replaced at year 40 the annualized capital cost is $5,200. If the intervention is **replacement**, then Figure 3-6 shows all of the necessary information.

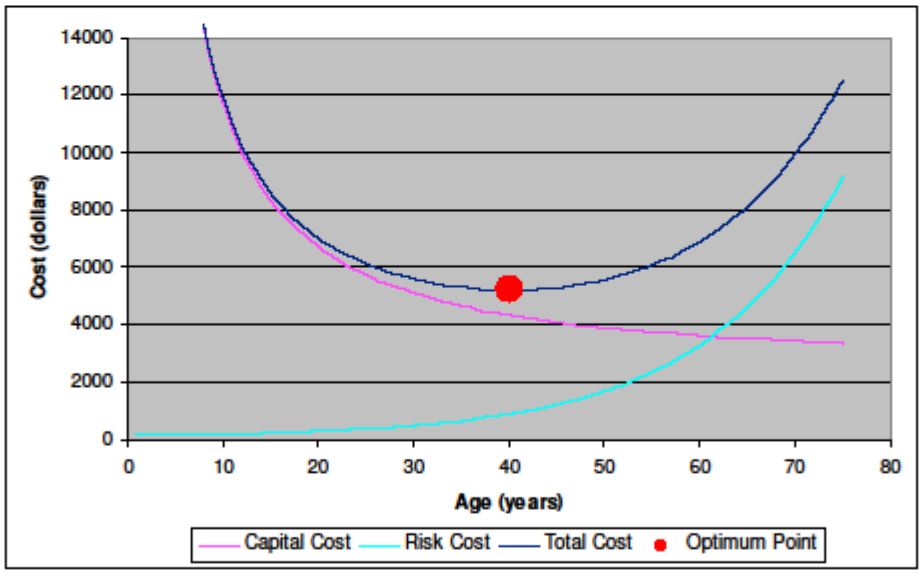


Figure 3-6 Example Risk Optimization with Simple Replacement

If the intervention is **refurbishment** then the analysis must be extended to include the ultimate optimal replacement. In such cases the optimal year for intervention becomes the optimal year for the *first* intervention. At this point in time the capital cost is increased by the cost of the intervention (assuming that the refurbishment cost is capitalized) and the risk cost is decreased in years after refurbishments by a factor that reflects effectiveness of the refurbishment. For example, a given refurbishment may decrease the probability of failure by 90%, but not return the unit to new condition. The results are illustrated in Figure 3-7. The optimal year for the first intervention to reduce risk was year 40 and the total cost (annual capital cost plus risk cost) at this point in time is $5,200. Since the capital cost is dropping slowly with each passing year, the risks costs only have to increase a small amount to justify a need for refurbishment. Figure 3-7 shows that $3,000 was spent to refurbish the asset in year 40, returning its Health Index to 1. At year 66 the increasing risk cost has made the next intervention optimal. At that point in time, the new total cost is $4,050. Since this is lower than the $5,200 at the original optimal point, then refurbishment would be the preferred alternative in this case.

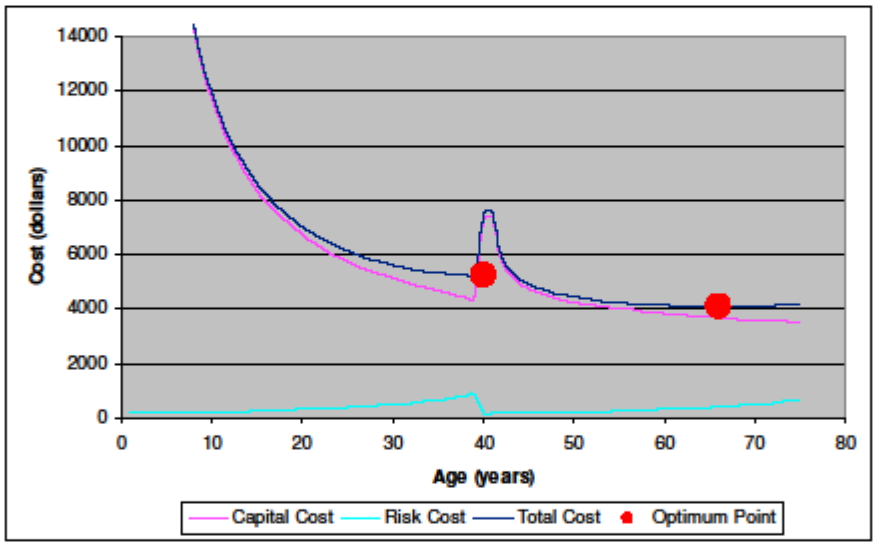


Figure 3-7 Example of Cost Effective Refurbishment

Had the refurbishment cost had been higher; say $50,000, then the next optimal replacement point would have occurred at a higher total annualized cost, indicating that the refurbishment was the more costly option. This situation is shown in Figure 3-8: the total annualized capital cost with refurbishment is $6,300 which is higher than the total annualized cost at the first optimal intervention point in time ($5,200). Consequently, in this case, the replacement at the first optimal year of intervention would be the preferred alternative.

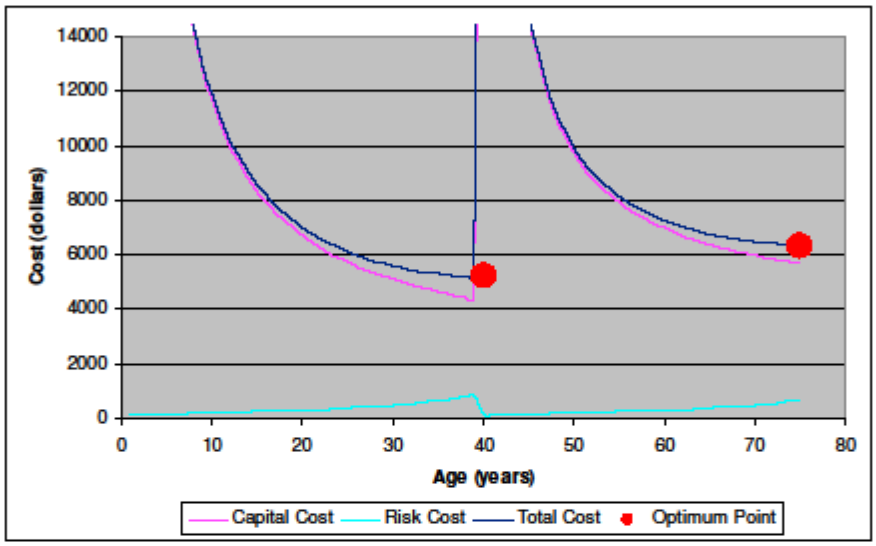


Figure 3-8 Example of Non Cost Effective Refurbishment

3.7 Development of the Replacement Capital Plan

Once the optimal year for refurbishment and replacement is known for every individual asset, the total capital plan is created by a simple addition in each year. This overall process determines how much replacement capital would be required in each future year, how much of it should be allocated to refurbishment, and identify specific assets which should be replaced or refurbished in each year.

3.8 Projected Replacement Capital Plan for "Simple Replacement" Assets

For many categories of distribution assets the only "risk" due to failure of a unit is that the unit needs to be replaced. That is, the "consequence" costs are very small. A probability of failure assessment was carried out where, based on the asset age distribution and type of asset, a certain percentage of the asset population are expected to fail each year. The equation that expresses this relation is as follows:

$$PF \equiv e^{(\beta(y-\alpha))}$$

where

PF is the probability of failure in year y
α and β are constants specific to each asset type

These constants may be "industry standard" values from the literature or they may be modified or "calibrated" to utility failure and replacement data if there is a sufficient sample both in terms of number of items and years in service. These constants may also be the subject of "expert opinion" in that the frequency of replacements may be more or less than the "industry standard" based on the local utility's experience. HOBNI only had sufficient failure data to fit α and β values for mini-pad transformers. However the adjusted α and β constants proved to predict more failures than HOBNI experiences. Likely this is due to the wide scatter of failures/year/age of unit and only 5 years worth of data.

3 ASSET CONDITION ASSESSMENT (ACA) METHODOLOGY

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4 EVALUATION OF MAINTENANCE PRACTICES

4. EVALUATION OF MAINTENANCE PRACTICES

4.1 HOBNI Inspection and Maintenance

The Distribution System Code's guidance on recommended inspection & maintenance practices for LDCs is intended to help maintain system reliability & safety. Good utility practices, inspections cycles, qualification of persons, defect repair, customer notification are addressed.

Hydro One Brampton Inc's Distribution System Maintenance and Inspection Procedures fall into two categories: Stations Maintenance & Lines Maintenance.

4.2 Stations Inspection and Maintenance

HOBNI Station Inspection and Maintenance Practices appear to meet or exceed OEB guidelines. Stations undergo detailed inspections every 2 yrs; less detailed inspections are performed monthly.

HOBNI's SCADA system is generally able to warn of problems prior to field inspection.

Inspection Parameters include:

- Transformer inspection including annual oil sampling.
- Breaker resistance checks.
- IR scans before inspection (IR Data is not recorded, but is simply acted on.)
- Electro-mechanical and digital relays are inspected in excess of published OEB inspection intervals
- Vegetation is sprayed annually each spring by a subcontractor licensed to perform this work.
- Corrective work is done by HOBNI except Doble testing at Jim Yarrow TS, which is contracted to ABB.
- Typical findings include:
    - CTs or relays out of alignment.
    - 4.16kV Stations: Electrical leakage on secondary bushing (Age related).
    - 13.8kV breakers take unacceptably long (8 cycles) to operate.
    - All of these items are addressed with corrective action.

4.3 Lines Inspection & Maintenance

HOBNI Lines Inspection & Maintenance Practices are generally reactive in nature. Following good utility practice, this maintenance meets OEB guidelines. Some characteristics include:

- No routine patrols.
- Forestry is performed on a 3 Year rotation, and is subcontracted to others.
- Insulator Washing is performed in February / March for glass insulators only.
- Annual infrared inspection (performed in the summer peak load season), and is subcontracted to others.
- Cable injection program for underground cables.
- Dry Ice cleaning of energized switchgear.
- Inspection is augmented by customer reports of system defects.
- Response Times for reactive maintenance are based on same day to 2 wks, depending on the nature of defects revealed in the maintenance plan.

HOBNI's inspection and maintenance practices for both stations and lines are based on accepted industry standards, are technically and financially sound, and meet with OEB requirements for good utility practices.

4.4 Vegetation Management

4.4.1 Introduction

HOBNI has rights to construct, operate and maintain electric utility distribution lines as a licensed Local Distribution Company. An important part of maintaining these lines is "Vegetation Management" which involves managing trees, plants and shrubs in the distribution easements within its service area. Wherever it is necessary for Hydro One Brampton to construct and install distribution lines through private property, these lands must be acquired by obtaining easements. An easement is defined as the area adjacent to any HOBNI overhead and underground equipment. Easements provide the land necessary for constructing, installing and maintaining lines at voltage levels of 44 KV and below. Keeping these easements free from obstructions is an important means of safeguarding the distribution plant and maintaining reliability standards.

4.4.2 Condition Assessment

Demographic information for easements has been collected from various sources included in HOBNI existing condition assessment and vegetation management programs. HOBNI manages about 806 km of lines and 12,469 units of underground equipment (i.e. mini-pads, pad-mount transformers & switchgears) that require tree clearance work. These must be maintained regularly to ensure the safe and reliable supply of electricity to HOBNI's customers. Hydro One Brampton's vegetation management program is on a three year cycle with the city divided into three Areas. See Figure 4-1.

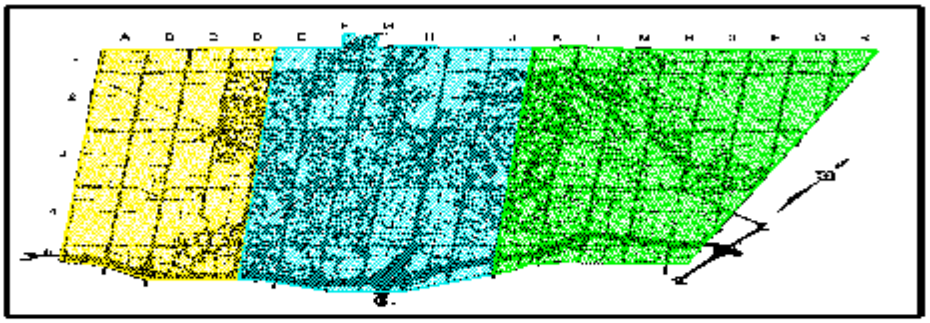


Figure 4-1 Trim Cycle Areas

- Area 1–2003, 2006, 2009, 2012
- Area 2–2005, 2008, 2011, 2014
- Area 3–2004, 2007, 2010, 2013

4.4.3 Trim Cycle

A three year trimming cycle has been established based on historical studies of our reliability statistics and trouble report system records.

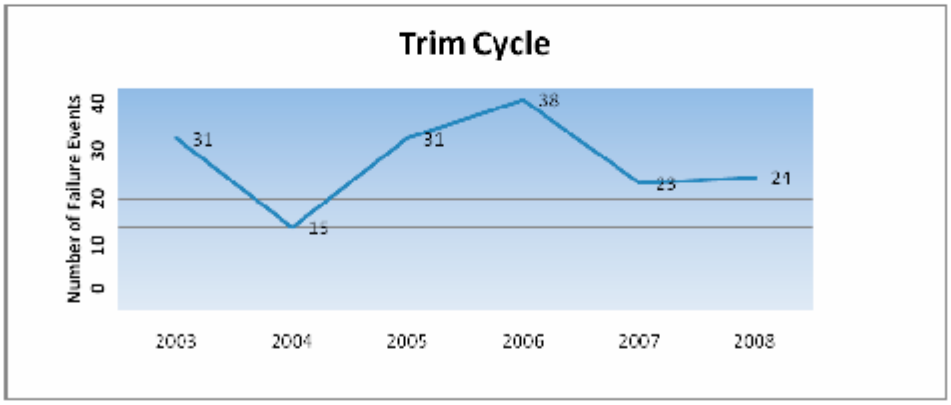
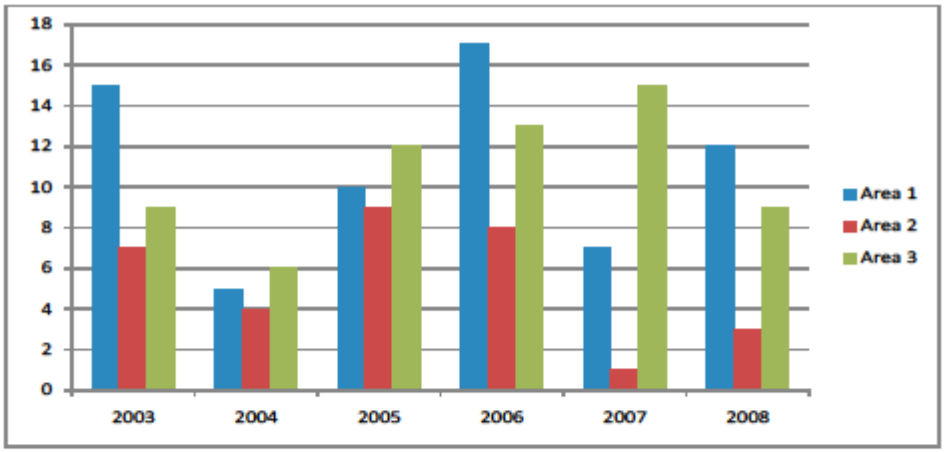


Figure 4-2 Trim Cycle and Number of Failure Events



Total =	31	15	31	38	23	24
Events						
Primary -	19	10	24	21	19	17
Secondary -	12	5	7	17	4	7

Prior to developing an Asset Management Plan, HOBNI adopted a three year trim cycle which includes full and spot trimming activities. The trimming season starts on the first working day of the year and is completed by Christmas each year. The program divides the City into defined trim areas. The order of completion is at the discretion of HOBNI. Based on current trim areas and cycles, the vegetation management program requires as estimated 4,200 person hours each year, excluding any emergency and off-cycle trimming. Vegetation Management is contracted out with the current tender running from 2007-2009. A new tender will be issued for 2010-2012 in December of 2009 so the historic three-year cycle can be maintained.

4.4.4 Contract

For operational purposes, HOBNI normally requests one proposal based on hourly labour and equipment costs for all general trimming in the City of Brampton. HOBNI tenders out to five tree trimming contractors. The contract budgeting has been as follows, $282,454 for 2006, $189,600 for 2007, $201,699 for 2008 and $230,000 for 2009. The forecasted budget for 2010 is $250,000 and the 2011/2012 budget will be based on a 3% increase for each year of the contract.

4 EVALUATION OF MAINTENANCE PRACTICES

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5 MUNICIPAL STATION (MS) TRANSFORMERS

5. MUNICIPAL STATION (MS) TRANSFORMERS

The application of distribution station transformers generally involves the step down of a higher to lower voltage. Substation transformers vary in capacity and ratings over a broad range. For Distribution stations, transformer ratings typically range from 5 MVA to 120 MVA.

Station transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary, secondary and, possibly, tertiary windings
- Laminated iron core
- Internal insulating media
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

Hydro One Brampton Networks Inc. currently has 18 station transformers.

5.1 Degradation Mechanism

For a majority of transformers, End-of-Life (EOL) is expected to be caused by the failure of the insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture.

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units with a probable high risk of failure. It is the ideal means on which to base an ongoing management strategy for aging transformers, identifying units that warrant consideration for continued use, consideration of remedial measures to extend life or identification of transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for substation transformers include the use of online monitors, capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks,

DC insulation resistance measurements and no-load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index, and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonic and/or electromagnetic detection and frequency response analysis.

The health indicator parameters for substation transformers usually include:

- Condition of the bushings
- Condition of transformer tank
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results
- Transformer age and winding temperature profiles
- Maximum loading profile

The anticipated life of transformers is often quoted as being 40 to 50 years. Many transformers in service are now approaching this age but failure rates remain low and there is little evidence that many are at, or near, EOL. There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Failure Mechanism of Station Transformers

1) **Thermal Aging:** Thermal aging involves the progress of chemical and physical changes because of chemical degradation reactions, polymerization, depolymerization, and diffusions.

2) **Electrical Aging:** Electrical aging, AC, impulse, or switching involves the effects of the following:

- partial discharges
- treeing
- electrolysis
- increased temperatures produced by high dielectric losses
- space charges

3) **Mechanical Aging**: Mechanical aging involves the following:

- fatigue failure of insulation components caused by a large number of low-level stress cycles
- thermo mechanical effects caused by thermal expansion and or contraction
- rupture of insulation by high levels of mechanical stress such as may be caused by external forces or operation condition of the equipment
- Insulation creep or flow under electrical, thermal, or mechanical stresses

5.2 Health Index Methodology

5.2.1 Health Index Formulation

The generic Health Index formulation for station transformers is shown below. Sufficient data existed to apply the formulas for station transformers. Note that asset age distribution and typical industry-established age-based failure curves are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m,max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

5 MUNICIPAL STATION (MS) TRANSFORMERS

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 5-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m,max}$
1	Insulation	6	4
2	Cooling	2	4
3	Sealing & connection	3	4
4	Reliability	3	4
Multiplying factor *		Table 5-12	

* Final Health Index result to be multiplied by a factor between 0-1 if applicable

Table 5-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	Oil quality	Table 5-7	8	4
2	Oil DGA	Table 5-8	10	4
3	Winding Doble	Table 5-9	10	4

Table 5-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	Temperature	Table 5-6	1	4

Table 5-4 Sealing & Connection (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	Tank oil leak	Table 5-6	2	4
2	Conservator oil level	Table 5-6	2	4
3	Grounding	Table 5-6	1	4
4	IR thermography	Table 5-6	10	4

Table 5-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	Loading	Table 5-11	10	4
2	Age	Table 5-10	6	4

5.2.2 Condition Criteria

5.2.2.1 *Individual Condition Based on Monthly Routine Inspection*

Table 5-6 Individual condition

Condition Rating	CPF	Condition Description
A	4	No Not_OK findings in past year
B	3	1 Not_OK work order in past year
C	2	2 Not_OK findings in past year
D	1	3 Not_OK findings in past year
E	0	> 3 Not_OK findings in past year

5.2.2.2 *Individual Condition Based on Measurement*

Oil Quality

Table 5-7 Oil Quality Test

Condition Rating	CPF	Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

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Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	2	3	4	Weight
Moisture PPM (T °C Corrected) (From DGA test)	<=20	<=30	<=40	>40	4
Dielectric Str. kV D877	>40	>30	>20	Less than 20	3
IFT dynes/cm 230 kV ≤ Voltage	>32	25-32	20-25	Less than 20	2 *
IFT dynes/cm 69 kV <Voltage< 230	>30	23-30	18-23	Less than 18	
IFT dynes/cm Voltage ≤ 69 kV	>25	20-25	15-20	Less than 15	
Color	Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number 230 kV ≤ Voltage	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
Acid Number 69 kV <Voltage< 230 kV	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
Acid Number Voltage ≤ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Regarding to IFT (Interfacial Tension), only 1 proper row is selected. The same for acid number

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight \times 4}$$

$$\text{For example if all data is available, overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{48}$$

Oil DGA (Dissolved Gas Analysis)

Table 5-8 Transformer DGA

Condition Rating *	CPF	Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

*In the case of a score other than A, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score B, 0.85 for score C, 0.75 for score D and 0.5 for score E.

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	5
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	1
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	1

$$\text{Overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{\sum \text{Weight} \times 4}$$

Winding Doble Test

Table 5-9 Winding Doble Test

Condition Rating	CPF	Description
A	4	Values well within acceptable ranges; power factor less than 0.05%
B	3	Values close to acceptable ranges; power factor between 0.05 - .5%
C	2	Values exceed acceptable ranges; power factor between 0.5 – 1%.
D	1	Values considerably exceed acceptable levels; power factor between 1 - 2%
E	0	Values are not acceptable> 2%, immediate attention required; power factor greater than 2%

5.2.2.3 Individual Condition Based on Transformer Intrinsic Characters

Age

Table 5-10 Transformer age (year)

Condition Rating	CPF	Condition Description
A	4	0-19
B	3	20-39
C	2	40-59
D	1	60-69
E	0	>=70

5.2.2.4 *Individual Condition Based on Operation Mode*

Loading History

Table 5-11 Loading history

Data: S1, S2, S3, ..., SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 $CPF = \frac{NA\times 4+NB\times 3+NC\times 2+ND\times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

5.2.2.5 *Expert Opinion*

Table 5-12 Expert opinion

Transformer station ID	De-rating multiplier	
	Multiple faults	Gassing issue
MS19	0.5	
MS20	0.5	
MS21	0.5	
MS22		0.5

5.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for station transformers:

- Available information includes DGA, Megger (no Doble), ratio and loading data. Furan is OK for some but not the others because the oil has been changed for some units. No maintenance record data (CM) are available
- No trouble reports are available
- There are 6 44/13.8 kV transformers of 1969-1976 vintage at MS 19-21 that have seen multiple, high magnitude, secondary/feeder faults. HOBNI is planning to replace one transformer/year beginning in 2010
- There is one spare rated at 44/13.8 kV and one at 27.6/4.16 kV
- Most transformers are NOT heavily loaded (some of the 44/13.8 are)
- Transformers in MS22 have gassing issues. Generally transformers manufactured from 1989-1991 have higher than normal failure rates throughout the industry
- Transformers in MS11 and MS12 have had bad Megger readings due to secondary insulator problems

5.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

The results of the field survey are shown below:

Table 5-13 Station Transformer Site Survey

	MS 14	MS 10	MS 8	MS1	MS 2	MS 12	MS 11	MS 15	MS 20	MS 22	MS 21	MS 17	MS 3
Age	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Bushing Condition	U	A	U	U	_	U	U	_	U	A	U	_	C
Oil Leaks	D	C	D	D	E	C	D	E	C	E	D	E	E
Main Tank/Cabinet Condition	B	A	B	B	E	C	C	E	C	E	C	E	E
[illegible]	B	A	B	B	E	B	C	E	C	E	D	E	E
[illegible]	C	A	B	B	E	D	C		D	E	C	E	E
Animal and Bird Condition	U	A	U	U	N	N	C	N	N	_	C	C	N
Primary Connections/Conductors Condition	U	D	U	D	E	U	U	E	U	E	C	E	E
Secondary Connections/Conduit Condition	U	B	U	B	E	U	U	E	U	E	C	E	E
[illegible]	B	A	C	B	E	B	B	E	B	E	B	E	E
[illegible]	A	B	B	B	N	N	N	N	N	A	B	N	N
Overall Power Transformer Condition	U	A	C	U	_	C	C	_	C	_	C	C	C
		[illegible]				[illegible]		[illegible]			[illegible]	[illegible]	[illegible]

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The site survey ratings are summarized as follows:

Table 5-14 Summary of Station Transformer Site Survey Ratings

	# A	#B	#C	#D
Bushing Condition	2	6	1	0
Oil Leaks	1	7	4	1
Main Tank/Cabinets Condition	1	7	5	0
Radiators and Conservator Condition	1	8	3	1
Gaskets and Seals Condition	1	4	5	1
Pumps and Fans Condition	1	4	3	0
Primary Connectors/Conductors Condition	0	6	2	0
Secondary Connections/Control Condition	0	6	2	0
Foundation/Support Steel/Grounding Condition	1	11	1	0
Fire Protection/Spill Containment	2	0	0	0
Overall Power Transformer Condition	1	5	7	0
sum	11	64	33	3
% of known	9.9%	57.7%	29.7%	2.7%

5.5 Health Index Distribution

The Health Index distribution is shown in Figure 5-1:

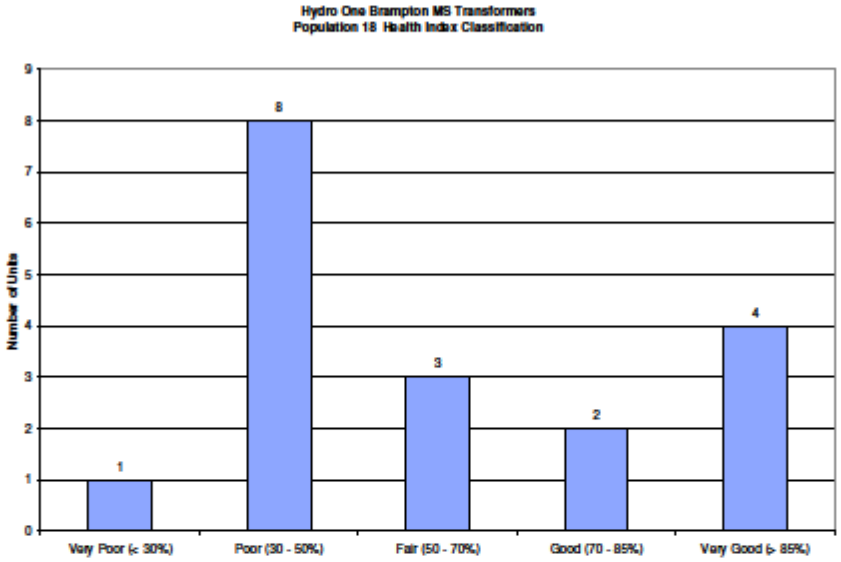


Figure 5-1 MS Transformers Health Index Distribution

The station transformers in the poor and very poor categories are as follows:

Classification	Transformer
Very Poor	MS19T2
Poor	MS8
	MS19T1
	MS20T1
	MS20T2
	MS21T1
	MS21T2
	MS22T1
	MS22T2

5.6 Age Distribution

The age distribution is shown on the following figure:

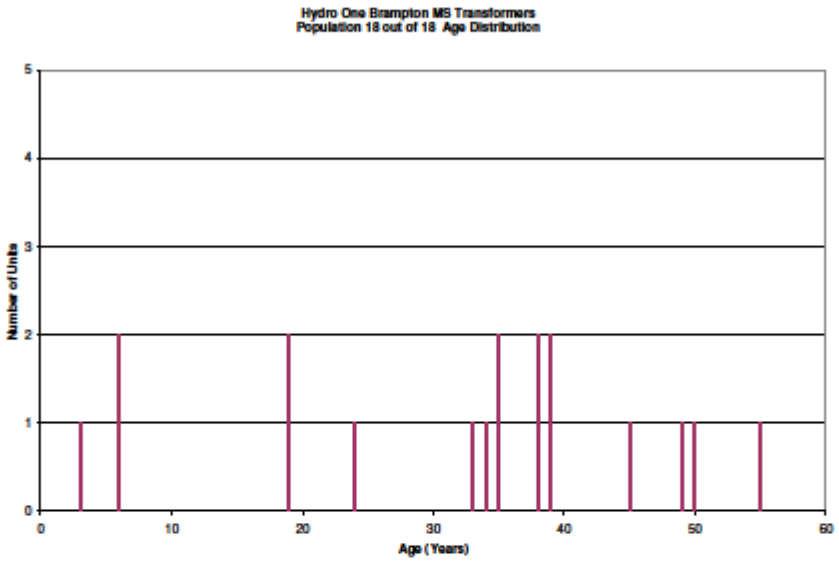


Figure 5-2 MS Transformers Age Distribution

5.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

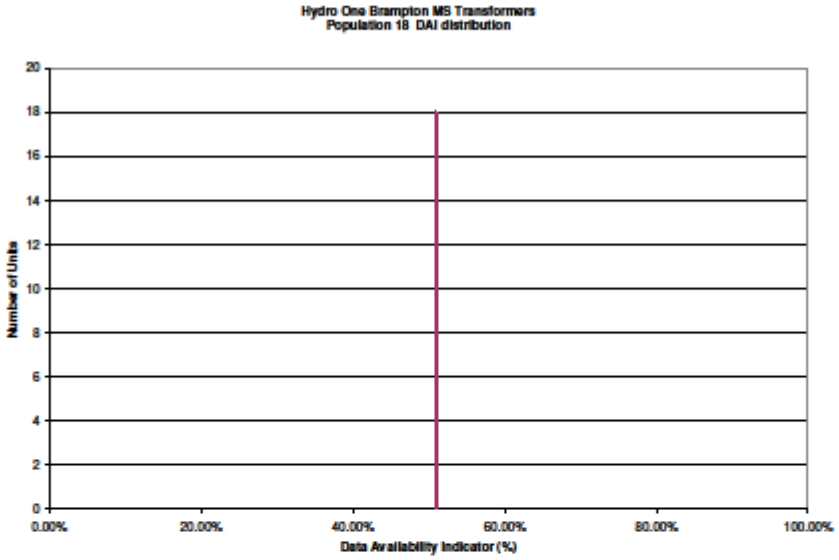


Figure 5-3 MS Transformers Data Availability Indicator Distribution

5.8 Optimal Capital Replacement Plan

The full risk vs. replace/refurbish risk analysis and replacement plan was carried out for the Station Transformers asset category. The following assumptions were used:

- The associated risk cost was the replacement cost + 2 x replacement cost.
- The risk mitigation cost was 50% of the replacement cost and the risk mitigation factor was 75%; i.e. refurbishing the transformer costs 50% of the cost to replace it and brings it to 75% of "as new" condition.

Using the preceding assumptions, no transformer was found to be a cost-effective candidate for refurbishment.

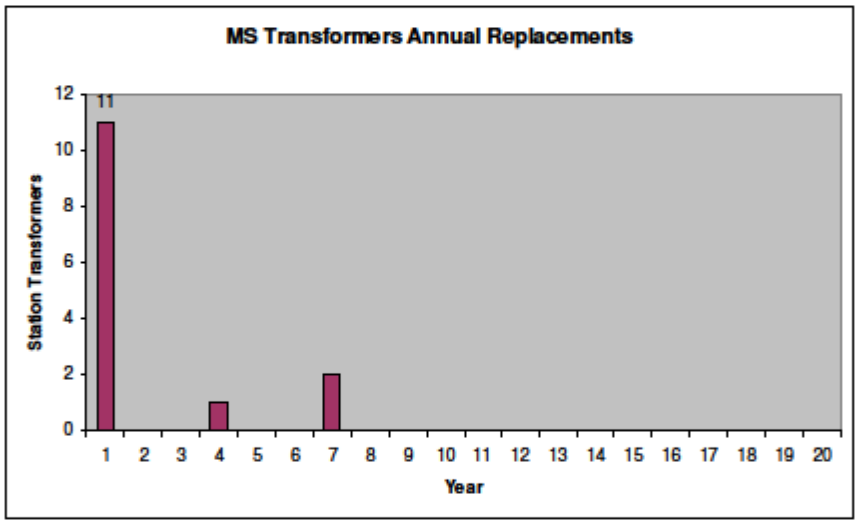


Figure 5-4 MS Transformers Optimal Yearly Replacements

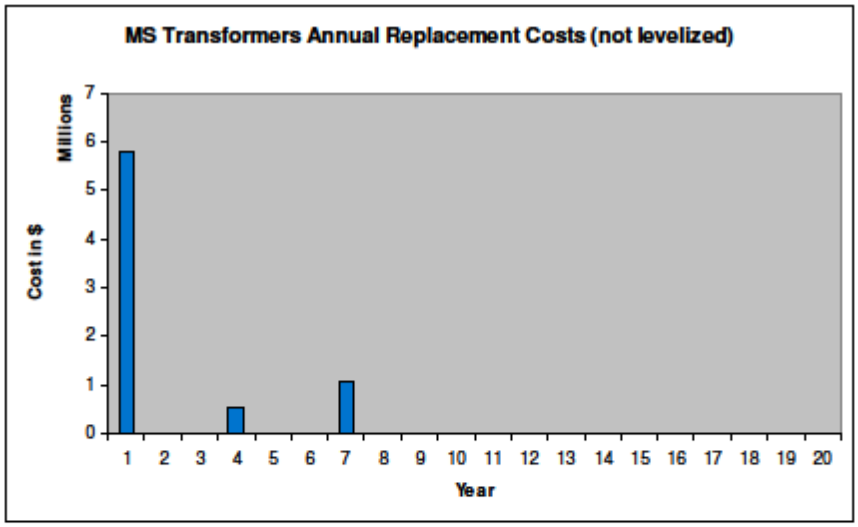


Figure 5-5 MS Transformers Optimal Yearly Replacements Cost

5.9 Levelized Capital Replacement Plan

Some of the *proactive* replacements of station transformers can be spread out over several years without significantly increasing the risk of failure thus resulting in more evenly spread annual expenditures. This is referred to as a "Levelized Capital Replacement Plan" and it is presented below:

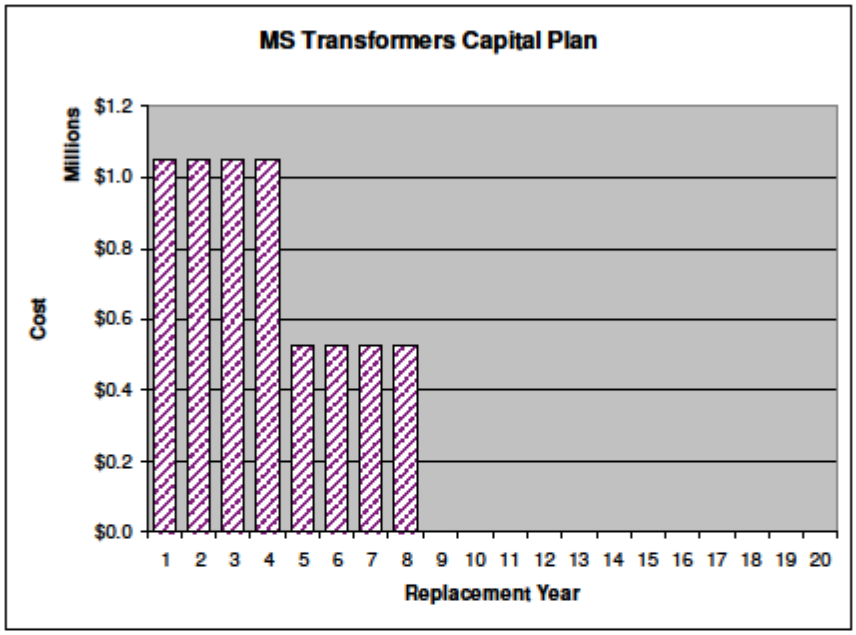


Figure 5-6 MS Transformers Levelized Capital Replacement Plan

5.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 115$ and $\beta = 0.051$. The median end of life for station transformers is 50 years. The maximum end of life is 85 years.

5.11 Data Gap Closure

This section outlines the data gap for station transformers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Oil quality
- Oil DGA
- Winding Doble
- Age

Data Gap

Type of Data Gap	Priority
Monthly Peak Loading (measurement)	P1
IR (measurement)	P1
temperature (measurement)	P1
Grounding (Corrective Maintenance or CM)	P2
Oil leaking (CM)	P3
Oil level (CM)	P3
Other CM or measurement	P3

6 CIRCUIT BREAKERS

6. CIRCUIT BREAKERS

The substation breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. Circuit breaker designs have evolved over the years and many different types are currently in use, such as oil circuit breakers, vacuum breakers, air magnetic circuit breakers, air blast circuit breakers (ABCB) and SF6 circuit breakers. Hydro One Brampton Networks Inc. currently employs 3 Oil, 3 SF6, 30Vacuum and 30 Magnetic Circuit Breakers. The vast majority of HOBNI's magnetic circuit breakers will be replaced within the next five years by vacuum breakers, and, because of that, magnetic breakers were not included in the condition assessment. It is also recommended that all the oil circuit breakers be replaced by the vacuum circuit breakers over the next 3 years.

6.1 Degradation Mechanism

Oil Circuit Breakers (OCB) represent the oldest type of breaker design and have been in use for over 70 years. Two types of designs exist among OCBs: bulk oil breakers (in which oil serves as the insulating and arc quenching medium) and minimum oil breakers (in which oil provides the arc quenching function only). Generally, 4 to 8 fully rated interruptions represent an OCB's useful service time between major maintenance intervals. This duty cycle can result in excessive contact erosion, carbonization of oil, and the need for maintenance.

Vacuum Breakers consist of fixed and moving butt type contacts in small evacuated chambers (i.e., bottles). A bellows attached to the moving contact permits the required short stroke to occur with no vacuum losses. Arc interruption occurs at current zero after withdrawal of the moving contact. Utilities typically install vacuum breakers indoors in metalclad switchgear. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully rated short circuits up to 100 times, and operate reliably over 30,000 or more switching operations. Vacuum breakers also are safe and protective of the environment.

SF6 Circuit Breakers were first developed in the late 1960s and are based on air blast technology. SF6 breakers interrupt currents by opening a blast valve and allowing high pressure SF6 to flow through a nozzle along the arc drawn between fixed and moving contacts. This process rapidly deionizes, cools and interrupts the arc. After interruption, the low-pressure gas is compressed for re-use in the next operation.

Substation breakers have many moving parts that are subject to wear and stress. They frequently "make" and "break" high currents and experience arcing that accompanies these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that can degrade surrounding insulation materials, nozzles, and interrupter chambers. Due to the mechanical energy required to achieve the high contact velocities of these assets this contributes mechanical deterioration to the degradation process.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker's specific duties. The

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International Council on Large Electric Systems' (CIGRE) has identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete
- Maintenance overhaul requirements
- Circuit breaker age

Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

- Corrosion
- Effects of moisture
- Bushing/insulator deterioration
- Mechanical

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problems in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil and gas leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections
- Oil contamination and/or leakage
- Deterioration of concrete foundation affecting stability of breakers

For OCBs, the interruption of load and fault currents involves the reaction under high pressure with large volumes of hydrogen gas and other arc decomposition products. Thus, both contacts and oil degrade more rapidly in OCBs than they do in either SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions with contact erosion and oil carbonization will lead to the

need for maintenance, including oil filtration. Oil breakers can also experience restrike when switching low load or line charging currents with high recovery voltage values. Sometimes this can lead to catastrophic breaker failures.

SF6 circuit breakers rarely fail from internal degradation or insulation breakdowns. When such failures do occur, they typically result from design or manufacture deficiencies, and they happen early in the breaker's life. There is insufficient experience with failures from long-term SF6 chamber degradation. SF6 insulation systems are sensitive to enhanced stress caused by metal particles or other protrusions on live parts. Metallic particles generated by moving metal parts in the tank can accumulate and cause internal flashovers. Particle initiated failures do not appear age-related, since the problem has occurred on relatively new breakers. Low temperatures have caused operational problems and failures of SF6 breakers. Most international testing standards for these breakers specify minimum temperatures of -30° C, but many cold-climate users require operation at -40° C or below. At low temperatures, early double pressure designs experienced gas leaks as well as mechanism and ancillary system problems, including failures. Single pressure designs also may have gas leaks, with gas seals and valves presenting weak points. SF6 loss and the ingress of moisture and air compromise breaker performance. Generally, earlier models have more problems than later ones, since modern equipment has improved seal and valve designs.

SF6 is extremely stable. Even at high arcing temperatures limited SF6 breakdown occurs. Also, with use of a suitable desiccant most breakdown products recombine to form SF6. Consequently, SF6 breakers can operate under fault conditions much longer than OCBs or ABCBs before needing maintenance. Manufacturers generally state that these breakers can perform 20 to 50 operations at full rated fault levels before requiring maintenance.

Recently, concerns have arisen about the greenhouse gas properties of SF6. It is one of the gases specifically mentioned in the Kyoto Agreement.

6.2 Health Index Methodology

6.2.1 Health Index Formulation

The generic Health Index formulation for circuit breakers is shown below. There was insufficient data to apply the formulas for circuit breakers. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{5} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{5} \alpha_m (CPS_{m\,max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n\,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n =0 when data unavailable)

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Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 6-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m			$CPS_{m.max}$
		Oil	Vacuum	SF6	
1	Operating mechanism	14	7	11	4
2	Contact performance	7	7	7	4
3	Arc extinction	9	2	5	4
4	Insulation	2	2	2	4
5	Reliability	5	5	5	4

Table 6-2 Operating Mechanism (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$			$CPF_{n.max}$
			Oil	Vacuum	SF6	
1	Lubrication (cm)	Table 6-7	9	5	7	4
2	Linkage (cm)	Table 6-7	5	2	4	4
3	Cabinet (cm)	Table 6-7	2	1	1	4

(cm) –- Corrective maintenance record

Table 6-3 Contact Performance (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$			$CPF_{n.max}$
			Oil	Vacuum	SF6	
1	Closing time	Table 6-8	3	3	3	4
2	Closing velocity	Table 6-8	3	3	3	4
3	Overtravel	Table 6-8	1	1	1	4
4	Trip time	Table 6-8	1	1	1	4
5	Trip velocity	Table 6-8	1	1	1	4
6	Trip-free time	Table 6-8	1	1	1	4
7	Contact R	Table 6-8				4
	Contact (cm)	Table 6-7	1	1	1	
8	Arcing contact	Table 6-12	1		1	4

Table 6-4 Arc Extinction (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$			$CPF_{n.max}$
			Oil	Vacuum	SF6	
1	Moisture (cm)	Table 6-7	8		4	4
2	Leakage (cm)	Table 6-7	1		1	4
3	Tank (cm)	Table 6-7	2	2	2	4
4	SF6 pressure (cm)	Table 6-7			1	4
5	Dewpoint	Table 6-13			4	4
6	Oil level	Table 6-7	1			4
7	Oil quality	Table 6-15	8			4

(cm) –- Corrective maintenance record

Table 6-5 Insulation (m=4) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1*	Power factor	Table 6-16	2	4
	Insulation (cm)	Table 6-7	2	4

(cm) -- Corrective maintenance record
* Insulation (cm) is adopted only when power factor data are not available.

Table 6-6 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$			$CPF_{n.max}$
			Oil	Vacuum	SF6	
1	Operating counter	Table 6-18	2	7	2	4
2	Loading	Table 6-20	2	2	2	4
3	Age	Table 6-17	1	1	1	4

6.2.2 Condition Criteria

6.2.2.1 ***Individual Condition Based on Corrective Maintenance Record (CM)***

A corrective maintenance work order implies that something was detected that required action. For a breaker in good condition, there should not be any such work orders.

However, on occasion, a deficiency is detected which requires action. It is assumed that once the action takes place, the asset is returned to good or 'as-new' condition. Repeated CM WOs (corrective maintenance work orders) for the same reason implies that some underlying problem and is indicative of poor condition of the asset. For the number of CM actions in the past year, the following condition criteria are proposed.

Table 6-7 Individual condition (closed CM)

Condition Rating	Factor	Condition Description
A	4	No CM work orders in past year
B	3	1 CM work order in past year
C	2	2 CM work orders in past year
D	1	> 2 CM work orders in past year
E	0	Problem cannot be corrected

6.2.2.2 ***Individual Condition Based on Measurement***

Circuit Breaker Timing and Contact Resistance

Breaker timing and contact resistance measurements indicate the proper function of the breaker as designed. It is crucial that the breaker meets these specifications for proper and reliable operation

Table 6-8 Timing and resistance test

Condition Rating	Factor	Condition Description
A	4	Measurement <= 80% Specification limit *
B	3	Measurement (80%, 100%] specification limit
D	1	Measurement (100%, 120%] specification limit
E	0	Measurement > 120% specification limit

* CB type dependent

Table 6-9 Specification limit for oil circuit breaker timing

Condition	<= 69 kV	>= 110 kV
Closing	250 ms	235 ms
Tripping	42 ms	25 ms
Trip-free dwell	67 ms	42 ms
Closing velocity	Manufacturer model/utility dependent	
Trip velocity	Manufacturer model/utility dependent	
Over-travel	Manufacturer model/utility dependent	

Table 6-10 Specification limit for gas circuit breaker timing

Condition	<= 69 kV	110 kV – 230 kV	>=345 kV
Closing	250 ms	142 ms	83 ms
Tripping	42 ms	42 ms	25 ms
Trip-free dwell	67 ms	42 ms	33 ms
Closing velocity	Manufacturer model/utility dependent		
Trip velocity	Manufacturer model/utility dependent		
Over-travel	Manufacturer model/utility dependent		

Table 6-11 Contact resistance specification limit

CB type	<= 69 kV	110 – 230 kV	345 kV	765 kV
Oil	300 u OHM	600 u OHM	900 u OHM	
Gas	150 u OHM	150 u OHM	150 u OHM	300 u OHM
Vacuum	250 u OHM	250 u OHM	250 u OHM	250 u OHM

Table 6-12 Arcing contact specification limit

CB type	Arcing contact length
Oil	Manufacturer model dependent
SF6	Manufacturer model dependent

Dewpoint, Oil Quality and SF6 Measurement

Table 6-13 Dewpoint specification limit

CB type	Dewpoint limit
SF6	-30 Deg. C at atmospheric pressure

Table 6-14 Dewpoint for SF6 CB

Condition Rating	Factor	Condition Description
A	4	<-30 Deg. C
B	3	Between -25 Deg. C and -30 Deg. C
C	2	Between -15 Deg. C and <-25 Deg. C
D	1	Between 0 Deg. C and <-15 Deg. C
E	0	> 0 Deg. C

Table 6-15 Oil dielectric strength specification limit

Condition Rating	Factor	Condition Description (D877)
A	4	> 40 kV
B	3	30 – 40 kV
D	1	20 – 30 kV
E	0	< 20 kV

Insulation Measurement

Table 6-16 Insulation specification limit

Condition Rating	Factor	Condition Description (PF at 20 Deg. C)
A	4	< 0.05%
B	3	0.05% - 0.5%
D	1	0.5% - 1%
E	0	1% - 2%

6.2.2.3 Individual Condition Based on CB Intrinsic Characteristic

Age

Table 6-17 Circuit breaker age (year)

Condition Rating	Factor	Condition Description
A	4	0-19
B	3	20-39
C	2	40-59
D	1	60-69
E	0	>=70

6.2.2.4 Individual Condition Based on Operation Mode

Operating Counter

Table 6-18 Operation frequency

Condition Rating	Factor	Condition Description
A	4	0 - 0.79
B	3	0.8 – 0.99
D	1	>=1

where operation_frequency = operating_counter/max_operation_limit

Table 6-19 CB type and maximum operation limits

CB type	Maximum operation limit
Oil	2000
SF6	10000
Vacuum	20000

Loading History

Table 6-20 Loading history

Data: S1, S2, S3, ..., SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Factor of Load= $\frac{NA\times 4+NB\times 3+NC\times 2+ND\times 1}{N}$
Note: If there are 2 numbers greater than 1.5, then the "Factor of Load" should be multiplied by 0.6 to show the effect of overheating.

6.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for circuit breakers:

- HOBNI has had no breaker failures at any of its stations to date
- No breaker failure but rather coordination issues when breakers don't clear faults quickly enough, so don't see the need to spend a lot of funds on intrusive maintenance

Oil Breakers

- Plan is to replace them with Vacuum breakers within 10 years
- There are only 2 only left and they will be refurbished and not replaced unless they fail: They will be replaced with Vacuum breakers as required

SF6

- The CBs are, in general, very new
- 2-year Preventative Maintenance cycle: visual inspection plus gas dew point test is done. All operation tests completed during the semi-annual maintenance; Gas gauge check is done monthly during station inspection
- All manufacturer recommendations are followed and are completed with the manufacturer representative present during semi-annual JYTS maintenance

Vacuum Breakers

- The CBs are, in general, very new (installed 2004 – 2007)
- Will have more once oil and air magnetic breakers are replaced over the next 4-5 years

Air Magnetic Breakers

- No need for ACA as they will be replaced within 4-5 years with Vacuum breakers. In relatively poor condition (all mid 1970's products)
- Health and safety hazard (asbestos) plus very slow to operate (8 cycles for some)

6.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Circuit breakers were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

The results of the field survey are shown below:

Table 6-21 Circuit Breakers Site Survey

	MS 14	MS1	MS 2	MS 19	MS 20	MS 22	MS 21	MS 17	MS 3
Bushing Condition	C	A	A	B	A	B	B	B	A
Tank Condition	N	A	A	B	A	B	B	C	A
Oil Leaks	N	A	A	B	A	N	B	N	A
Controls and Mechanism	U	A	A	B	A	U	B	U	A
Overall Breaker Condition	B	A	A	B	A	B	B	C	A
	surface rust on control cabinet	new vacuum	new vacuum		new vacuum	SF6	replacing this year with vacuum, too hard to get parts	vacuum, bought used	new vacuum

The site survey ratings are summarized as follows:

Table 6-22 Summary of Circuit Breakers Site Survey Ratings

	# A	#B	#C	#D
Bushing Condition	4	4	1	0
Tank Condition	4	3	1	0
Oil Leaks	4	2	0	0
Controls and Mechanism	4	2	0	0
Overall Breaker Condition	4	4	1	0
sum	20	15	3	0
% of known	52.6%	39.5%	7.9%	0.0%

6.5 Health Index Distribution

The Health Index distribution for oil breakers is shown below:

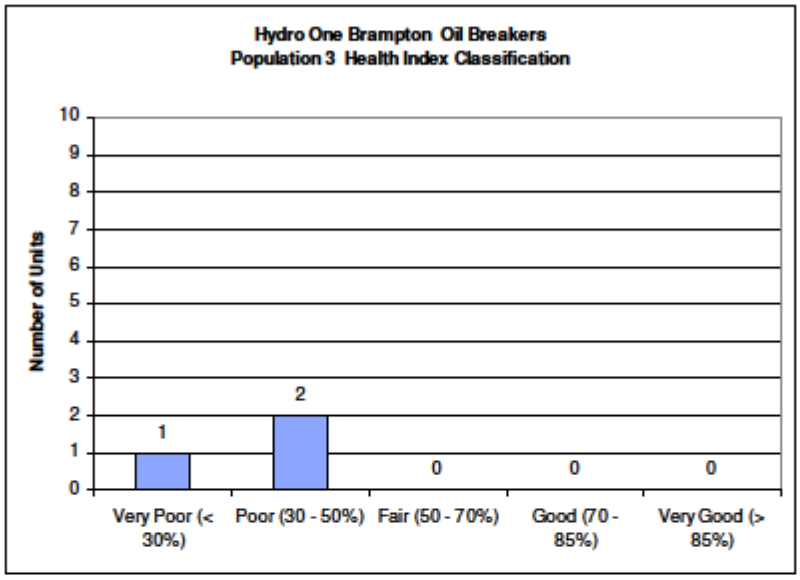


Figure 6-1 Oil Circuit Breakers Health Index Distribution

The oil circuit breakers in the poor / very poor category are:

Classification	Circuit Breaker
Very Poor	8F1
Poor	8F2
	8F3

The Health Index distribution for SF6 breakers is shown on the figure below:

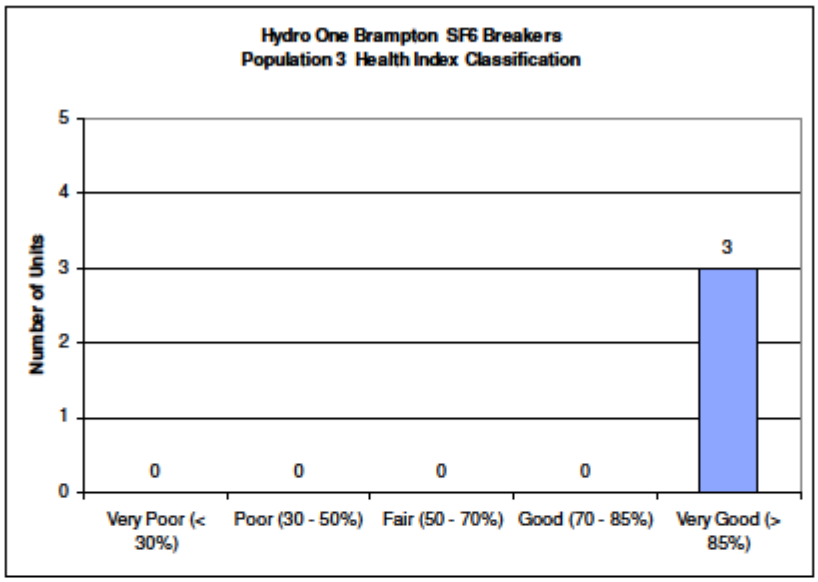


Figure 6-2 SF6 Circuit Breakers Health Index Distribution

The Health Index distribution for vacuum breakers is shown on the figure below:

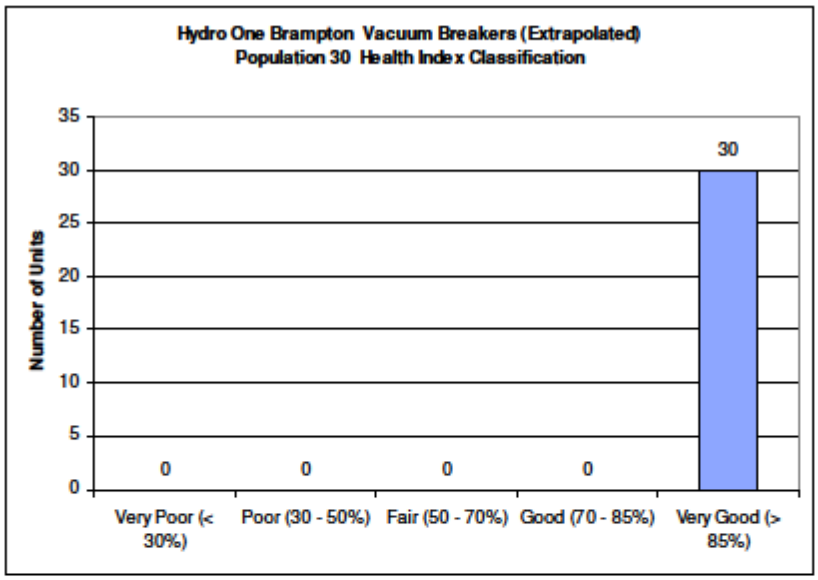


Figure 6-3 Vacuum Breakers Health Index Distribution

6.6 Age Distribution

The age distribution for oil breakers is shown on the figure below:

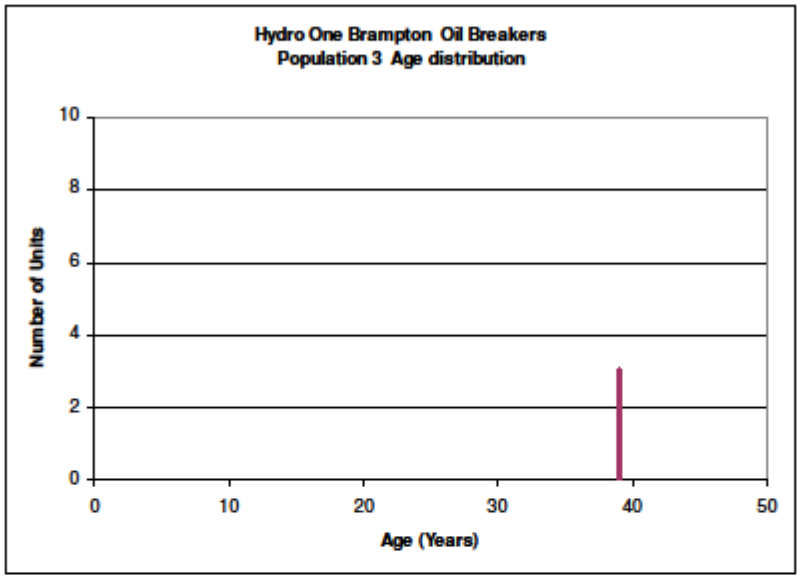


Figure 6-4 Oil Circuit Breakers Age Distribution

6 CIRCUIT BREAKERS

The age distribution for SF6 breakers is shown on the figure below:

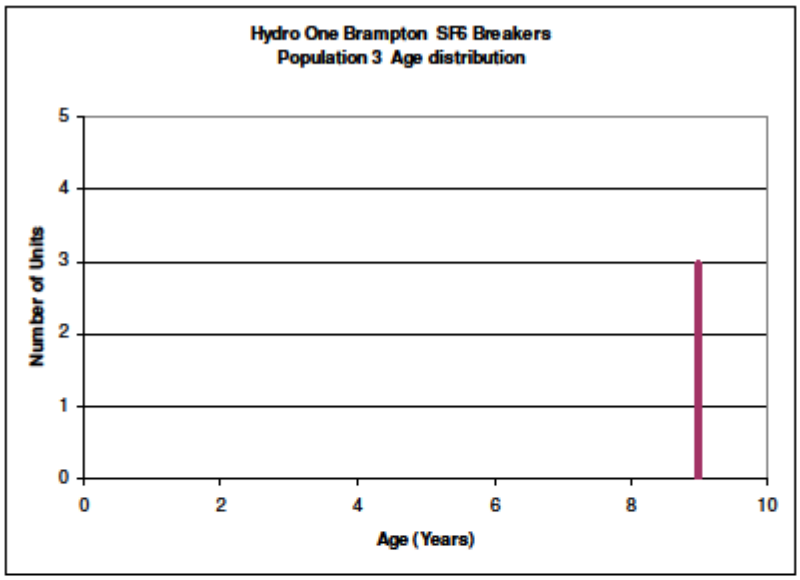


Figure 6-5 SF6 Circuit Breakers Age Distribution

6 CIRCUIT BREAKERS

The age distribution for vacuum breakers is shown on the figure below:

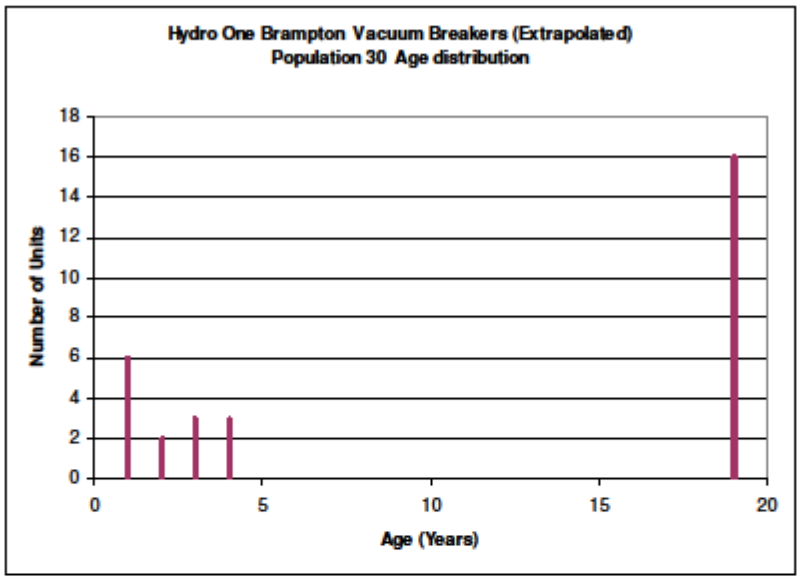


Figure 6-6 Vacuum Breakers Age Distribution

6.7 Data Availability Indicator

The Data Availability Indicator (DAI) for oil breakers is shown on the following figure:

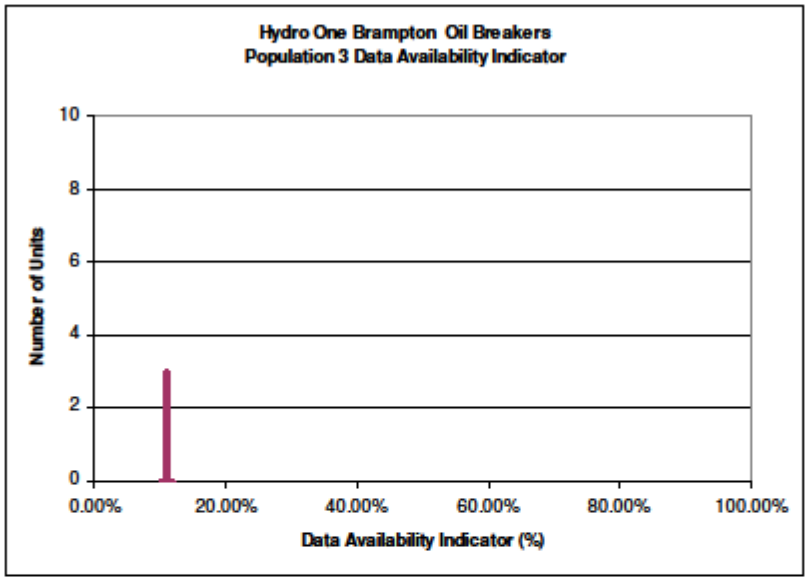


Figure 6-7 Oil Circuit Breakers Data Availability Indicator Distribution

The Data Availability Indicator (DAI) for SF6 breakers is shown on the following figure:

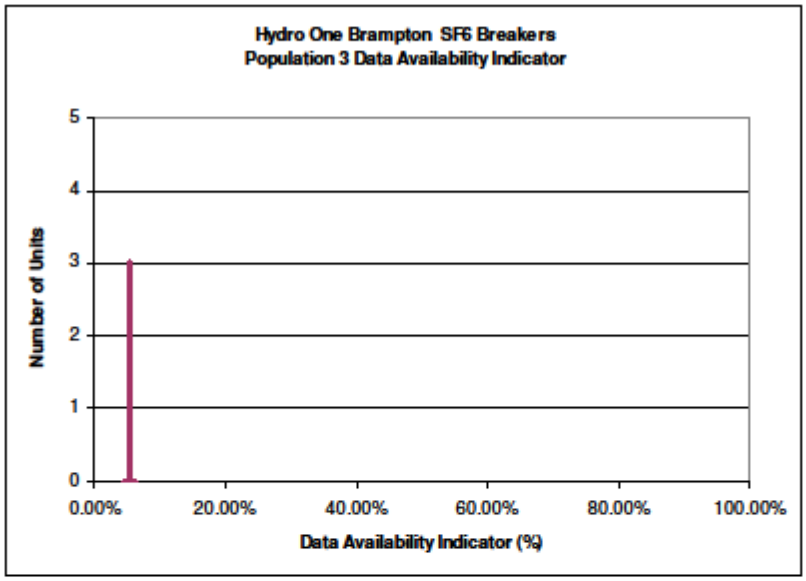


Figure 6-8 Circuit Breakers Data Availability Indicator Distribution

The Data Availability Indicator (DAI) for vacuum breakers is shown on the following figure:

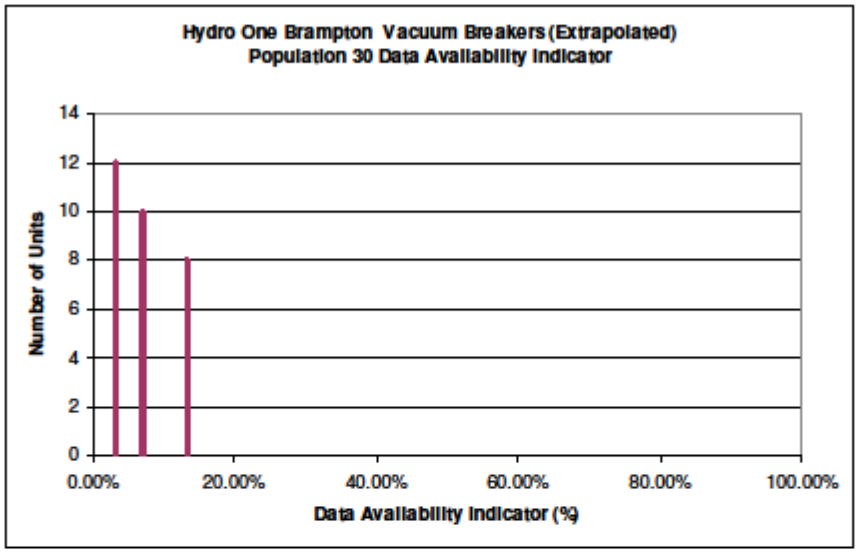


Figure 6-9 Vacuum Breakers Data Availability Indicator Distribution

6.8 Optimal Capital Replacement Plan

As for circuit breakers, a full risk analysis, replace vs. refurbish assessment was performed with the following assumptions:

- The associated risk cost was the replacement cost + 2 x replacement cost.
- The risk mitigation cost was 50% of the replacement cost and the risk mitigation factor was 75%; i.e. refurbishing the circuit breaker brings it to 75% of "as new" condition.
- The risk assessment was done for all the breaker types rather than producing assessments for each category.

Using the preceding assumptions, no circuit breaker was found to be a cost-effective candidate for refurbishment.

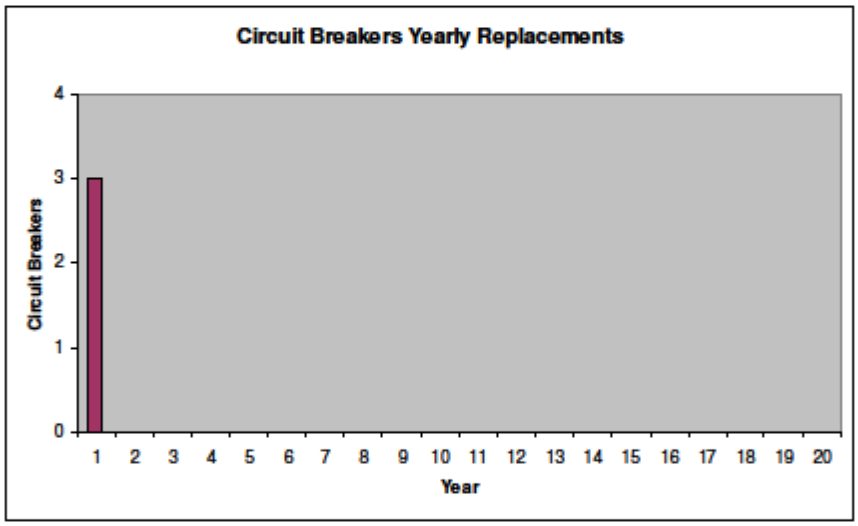


Figure 6-10 Circuit Breakers Optimal Yearly Replacements

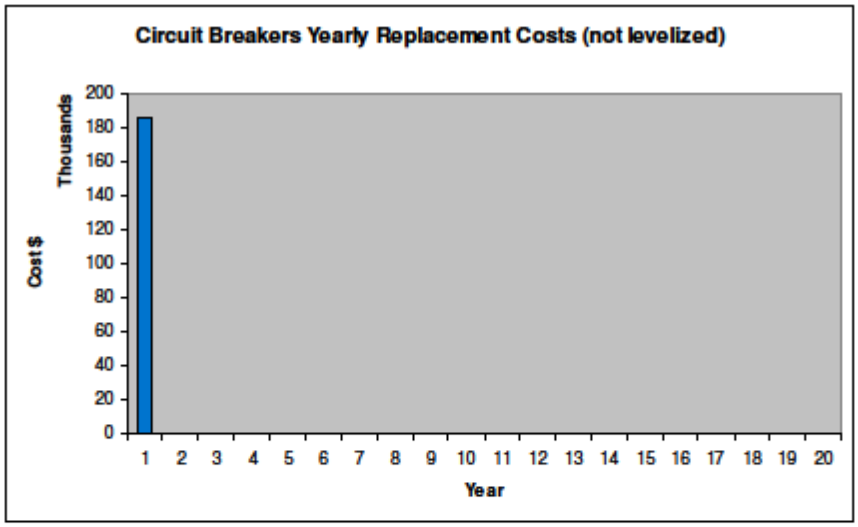


Figure 6-11 Circuit Breakers Optimal Yearly Replacements Cost

6.9 Levelized Capital Replacement Plan

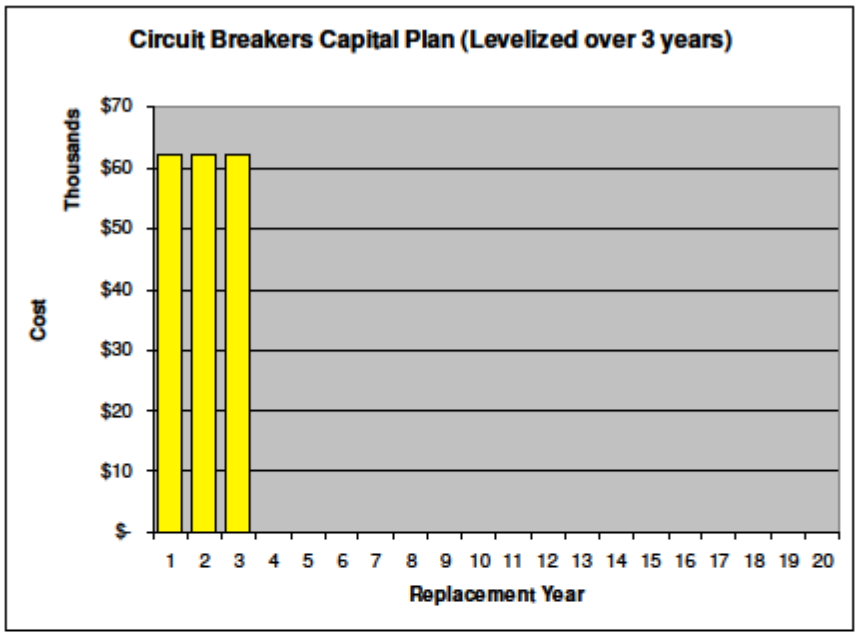


Figure 6-12 Level Circuit Breakers Capital Replacement Plan

6.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 83$ and $\beta = 0.114$. The median end of life for circuit breakers is 60 years. The maximum end of life is 75 years.

6.11 Data Gap Closure

This section outlines the data gap for circuit breakers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Contact resistance
- Insulation resistance
- Age

Data Gap

Type of Data Gap	Priority
Breaker timing (measurement)	P1
Operating counting (measurement)	P1
Oil quality (measurement)	P1
Lubrication (CM)	P1
Linkage (CM)	P2
Monthly Peak Loading (measurement)	P2
Power factor (measurement)	P2
Dewpoint (CM)	P2
Moisture (CM)	P2
Tank/bottle (CM)	P2
Other CM or measurement	P3

7 SINGLE PHASE POLE MOUNTED TRANSFORMERS

7. SINGLE PHASE POLE MOUNTED TRANSFORMERS

HOBNI's distribution transformers include single phase pole mounted transformers. There are currently 1544 single phase pole mounted transformers in use. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid.

7.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

7.2 Health Index Methodology

7.2.1 Health Index Formulation

The generic Health Index formulation for pole mounted transformers is shown below. There was insufficient data to apply the formulas for pole mounted transformers. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m,max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n =0 when data unavailable)

7 SINGLE PHASE POLE MOUNTED TRANSFORMERS

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 7-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m				$CPS_{m,max}$
		Pad Mounted	Pole Mounted	Submer-sible	Vault	
1	Physical condition	3	1	7	7	4
2	Cooling	5	1	5	5	4
3	Environment	5	3	5	5	4
4	Reliability	5	4	5	5	4

Table 7-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	Corrosion	Table 7-6	3	1	3	3	4
2	Access	Table 7-7	1		1	1	4
3	Base	Table 7-8	2				4
4	Housekeeping	Table 7-10				5	4

Table 7-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	IR scan	Table 7-12	2			2	4
2	Oil leak	Table 7-9	1	1	1	1	4

Table 7-4 Environment (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	PCB	Table 7-13	1	1	1	1	4

Table 7-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	overall	Table 7-11	2	2	2	2	4
2	age	Table 7-14	1	1	1	1	4

7.2.2 Condition Criteria

7.2.2.1 *Individual Condition Based on Site Inspection*

Table 7-6 Corrosion condition

Condition Description	CPF
None	4
Layers	1
Rust	0
Skirt	1
Painting	2
Graffiti	3
Surface	0
Stickers	2

Table 7-7 Access condition

Condition Description	CPF
O.K.	4
Problem	0
Fence	0
Tree/shrub	0

Table 7-8 Base condition

Condition Description	CPF
Good	4
Fair	2
Needs repairs	0

Table 7-9 Oil leak condition

Condition Description	CPF
Oil	0
No	4

Table 7-10 Housekeeping condition

Condition Description	CPF
Cleaning	2
Lighting	3
Other	1
None	4

Table 7-11 Overall condition

Condition Description	CPF
No	4
Follow-up	3
Correct	1
Immediate	0

7.2.2.2 *Individual Condition Based on Measurement*

Table 7-12 IR Scan condition

Condition Description (ΔT)	CPF
0	4
3	3
5	2
10	1
15	0

Table 7-13 PCB condition

Condition Description (ppm)	CPF
0	4
2.01	3
50.01	1
500.01	0

7.2.2.3 *Individual Condition Based on Transformer Intrinsic Characteristics*

Age

Table 7-14 Transformer age (year)

Condition Rating	CPF	Condition Criteria			
		Pad	Pole	Submersible	Vault
A	4	0	0	0	0
B	3	40	30	25	40
C	2	50	50	35	50
D	1	60	60	40	60
E	0	61	61	41	61

7.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for pole mounted transformers:

- Usually run to failure with no explicit testing
- In general, pole-mounted transformers are in good shape, with no particular issues.
- OEB inspection results are available
- PCB testing is ongoing to meet regulations
- 16 kV bushings have lower BIL on older units
- Replace delta with star program is in place during planned relocations

7.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

The results of the field survey are shown below. Note that the table includes both single phase and three phase pole mounted transformers, as no distinction was made at the time of the survey. Thus it is the same as the Table 8-15 of this report.

Table 7-15 Pole Mounted Transformer Survey

Pole Mounted Transformer Location	Chingacousy/Flowertown	1272 Queen St.	2100 Embleton Rd., Huttonville	9108 Heritage Rd.	7935 Kennedy Rd.	Marsden & Cornwall	Dean St. West of Kennedy	Centre & McCaul	Eagleridge & Torbram	11623 Dixie Rd.
Tank Integrity	B	C	B	C	C	C	B	C	A	B
Oil Leak	A	B	A	A	A	A	A	A	A	A
Bushing Condition	B	B	B	B	B	C	B	B	A	B
Electrical Connections	B	B	B	B	B	C	B	C	A	A
Signs of Overheating?	A	A	A	A	A	A	A	A	A	A
Overall Transformer Condition	B	C	B	C	B	C	B	C	A	B

The site survey ratings are summarized as follows. Note that the table includes both single phase and three phase pole mounted transformers, as no distinction was made at the time of the survey.

Table 7-16 Summary of Pole Mounted Transformer Ratings

	#A	#B	#C	#D
Tank Integrity	1	4	5	0
Oil Leak	9	1	0	0
Bushing Condition	1	8	1	0
Electrical Connections	2	6	2	0
Signs of Overheating?	10	0	0	0
Overall Transformer Condition	1	5	4	0
Sum	24	24	12	0
% of Known	40.0%	40.0%	20.0%	0.0%

7.5 Health Index Distribution

The Health Index distribution is shown on the figure below:

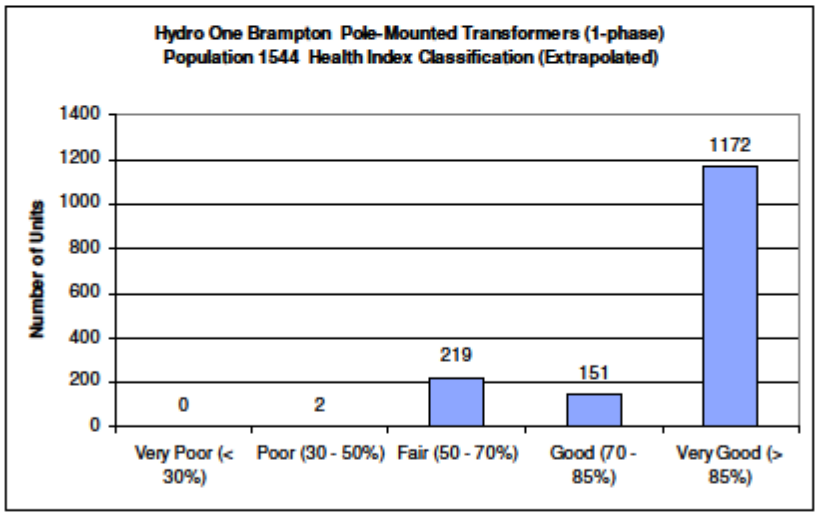


Figure 7-1 Single Phase Pole Mounted Transformers Health Index Distribution

The units in the poor/very poor category are as follows:

Classification	Transformer	Cause
Poor	T10587	due to corrosion
	T07748	due to corrosion

7.6 Age Distribution

The age distribution is shown on the figure below:

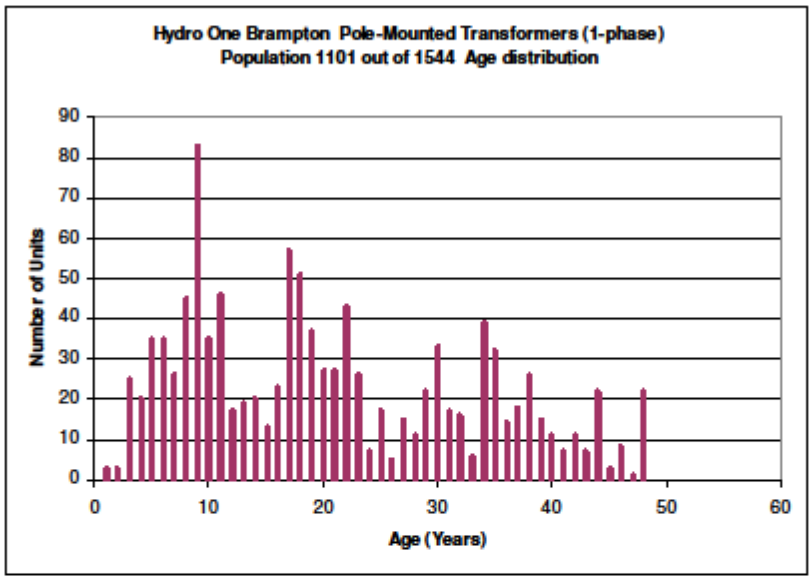


Figure 7-2 Single Phase Pole Mounted Transformers Age Distribution

7.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

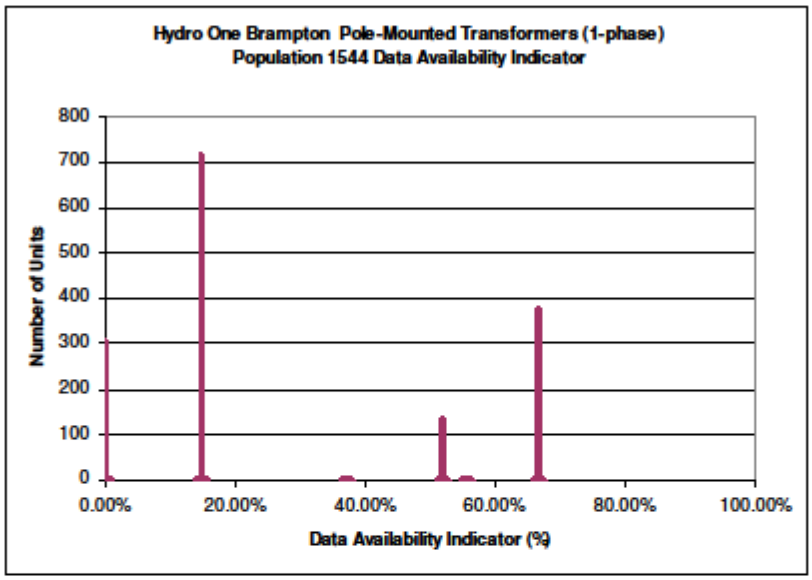


Figure 7-3 Single Phase Pole Mounted Transformers Data Availability Distribution

7.8 Capital Replacement Plan

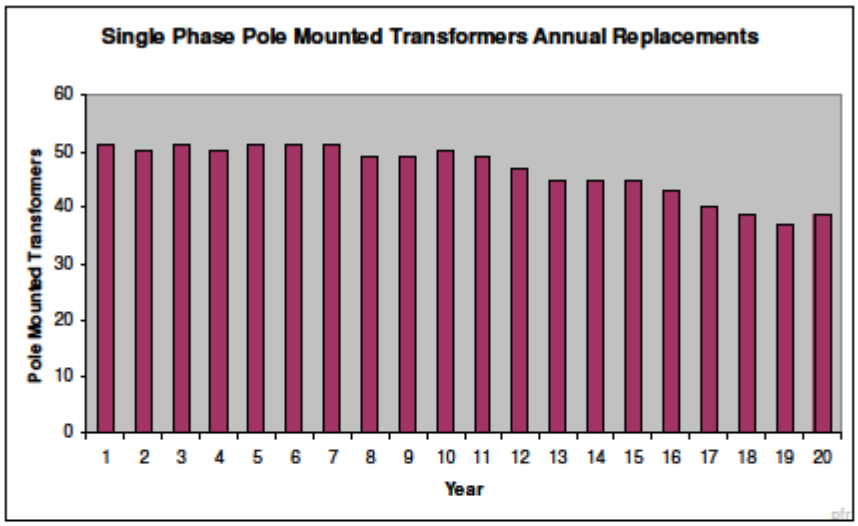


Figure 7-4 Single Phase Pole Mounted Transformers Yearly "Probable Failure" Replacements

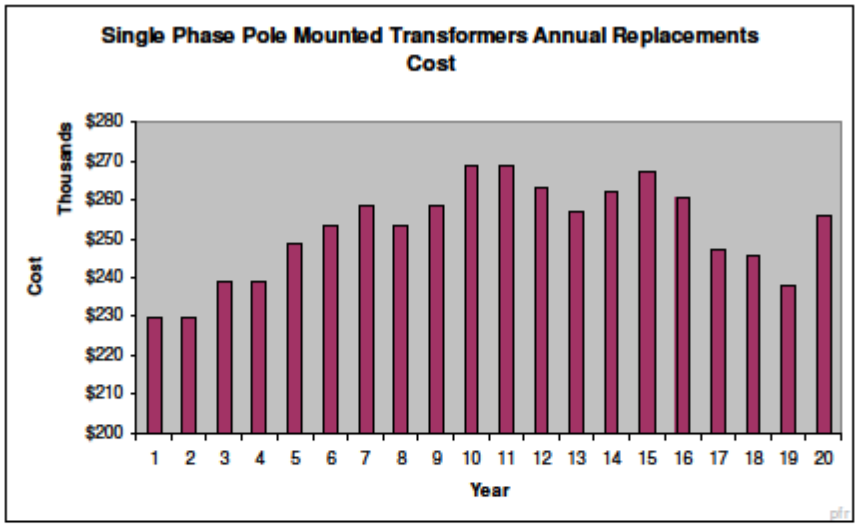


Figure 7-5 Single Phase Pole Mounted Transformers Yearly "Probable Failure" Replacements Cost

7.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement Plan is not applicable for this asset, as the Capital Replacement Plan approach is *reactive*.

7.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 87$ and $\beta = 0.055$. The median end of life for pole mounted transformers is 30 years. The maximum end of life is 60 years.

7.11 Data Gap Closure

This section outlines the data gap for distribution transformers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Inspection results (not including submersible transformers)
- PCB
- Age

Data Gap

Type of Data Gap	Priority
Monthly Peak Loading (measurement)	P1
Overall condition (CM)	P1
Corrosion (CM)	P2
IR (measurement)	P1
Access (CM)	P3
Other CM or measurement	P3

7 SINGLE PHASE POLE MOUNTED TRANSFORMERS

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8 THREE PHASE POLE MOUNTED TRANSFORMERS

8. THREE PHASE POLE MOUNTED TRANSFORMERS

HOBNI's distribution transformers include three phase pole mounted transformers. There are currently 404 three phase pole mounted transformers in use. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid. All of these designs employ sealed tank construction.

8.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

8.2 Health Index Methodology

8.2.1 Health Index Formulation

The generic Health Index formulation for pole mounted transformers is shown below. There was insufficient data to apply the formulas for pole mounted transformers. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m\,max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n\,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

8 THREE PHASE POLE MOUNTED TRANSFORMERS

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 8-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m				$CPS_{m,max}$
		Pad Mounted	Pole Mounted	Submer-sible	Vault	
1	Physical condition	3	1	7	7	4
2	Cooling	5	1	5	5	4
3	Environment	5	3	5	5	4
4	Reliability	5	4	5	5	4

Table 8-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	Corrosion	Table 8-6	3	1	3	3	4
2	Access	Table 8-7	1		1	1	4
3	Base	Table 8-8	2				4
4	Housekeeping	Table 8-10				5	4

Table 8-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	IR scan	Table 8-12	2			2	4
2	Oil leak	Table 8-9	1	1	1	1	4

Table 8-4 Environment (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	PCB	Table 8-13	1	1	1	1	4

Table 8-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	overall	Table 8-11	2	2	2	2	4
2	age	Table 8-14	1	1	1	1	4

8.2.2 Condition Criteria

8.2.2.1 *Individual Condition Based on Site Inspection*

Table 8-6 Corrosion condition

Condition Description	CPF
None	4
Layers	1
Rust	0
Skirt	1
Painting	2
Graffiti	3
Surface	0
Stickers	2

Table 8-7 Access condition

Condition Description	CPF
O.K.	4
Problem	0
Fence	0
Tree/shrub	0

Table 8-8 Base condition

Condition Description	CPF
Good	4
Fair	2
Needs repairs	0

Table 8-9 Oil leak condition

Condition Description	CPF
Oil	0
No	4

Table 8-10 Housekeeping condition

Condition Description	CPF
Cleaning	2
Lighting	3
Other	1
None	4

Table 8-11 Overall condition

Condition Description	CPF
No	4
Follow-up	3
Correct	1
Immediate	0

8.2.2.2 *Individual Condition Based on Measurement*

Table 8-12 IR Scan condition

Condition Description (ΔT)	CPF
0	4
3	3
5	2
10	1
15	0

Table 8-13 PCB condition

Condition Description (ppm)	CPF
0	4
2.01	3
50.01	1
500.01	0

8.2.2.3 *Individual Condition Based on Transformer Intrinsic Characteristics*

Age

Table 8-14 Transformer age (year)

Condition Rating	CPF	Condition Criteria			
		Pad	Pole	Submersible	Vault
A	4	0	0	0	0
B	3	40	30	25	40
C	2	50	50	35	50
D	1	60	60	40	60
E	0	61	61	41	61

8.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for three-phase pole mounted transformers:

- Usually run to failure with no explicit testing
- In general, pole-mounted transformers are in good shape, with no particular issues.
- OEB inspection results are available
- PCB testing is ongoing to meet regulations
- 16 kV bushings have lower BIL on older units
- There is a program in place to replace delta with star configuration during planned relocations

8.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

The results of the field survey are shown below. Note that the table includes both single phase and three phase pole mounted transformers, as no distinction was made at the time of the survey. Thus is it the same as the Table 7-15 of this report.

Table 8-15 Pole Mounted Transformer Survey

Pole Mounted Transformer Location	Chingacousy/Flowertown	1272 Queen St.	2100 Embleton Rd., Huttonville	9108 Heritage Rd.	7935 Kennedy Rd.	Marsden & Cornwall	Dean St. West of Kennedy	Centre & McCaul	Eagleridge & Torbram	11623 Dixie Rd.
Tank Integrity	B	C	B	C	C	C	B	C	A	B
Oil Leak	A	B	A	A	A	A	A	A	A	A
Bushing Condition	B	B	B	B	B	C	B	B	A	B
Electrical Connections	B	B	B	B	B	C	B	C	A	A
Signs of Overheating?	A	A	A	A	A	A	A	A	A	A
Overall Transformer Condition	B	C	B	C	B	C	B	C	A	B

The site survey ratings are summarized as follows. Note that the table includes both single phase and three phase pole mounted transformers, as no distinction was made at the time of the survey.

Table 8-16 Summary of Pole Mounted Transformer Ratings

	#A	#B	#C	#D
Tank Integrity	1	4	5	0
Oil Leak	9	1	0	0
Bushing Condition	1	8	1	0
Electrical Connections	2	6	2	0
Signs of Overheating?	10	0	0	0
Overall Transformer Condition	1	5	4	0
Sum	24	24	12	0
% of Known	40.0%	40.0%	20.0%	0.0%

8.5 Health Index Distribution

The Health Index distribution is shown on the figure below:

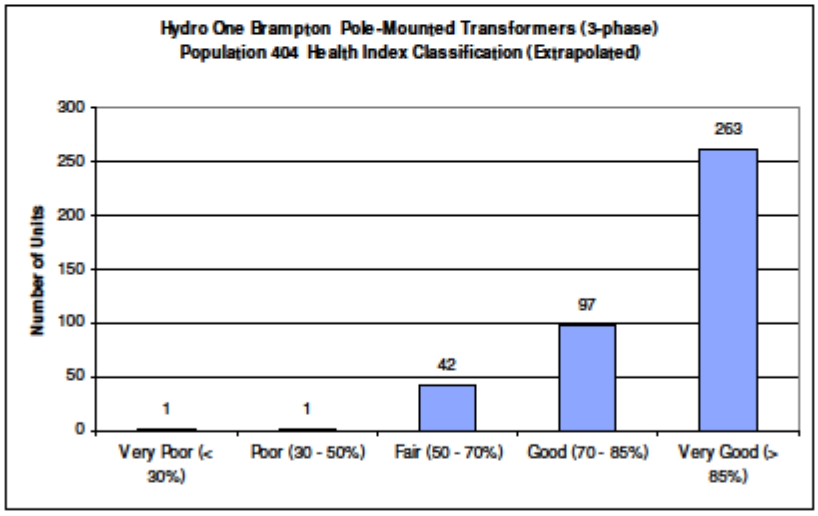


Figure 8-1 Three Phase Pole Mounted Transformers Health Index Distribution

The transformers in poor/very poor condition are:

Classification	Transformer	Cause
Very Poor	T01637	due to corrosion and oil leak
Poor	T00851	due to corrosion

8.6 Age Distribution

The age distribution is shown on the figure below:

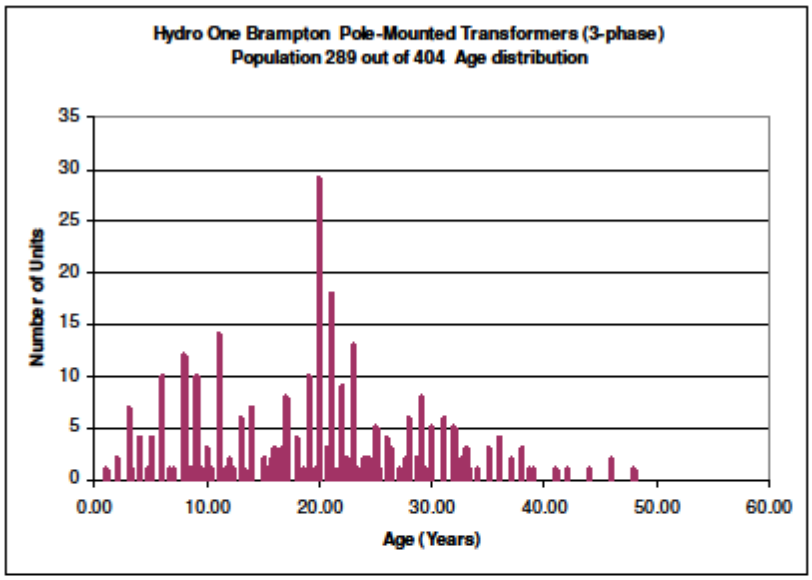


Figure 8-2 Three Phase Pole Mounted Transformers Age Distribution

8.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

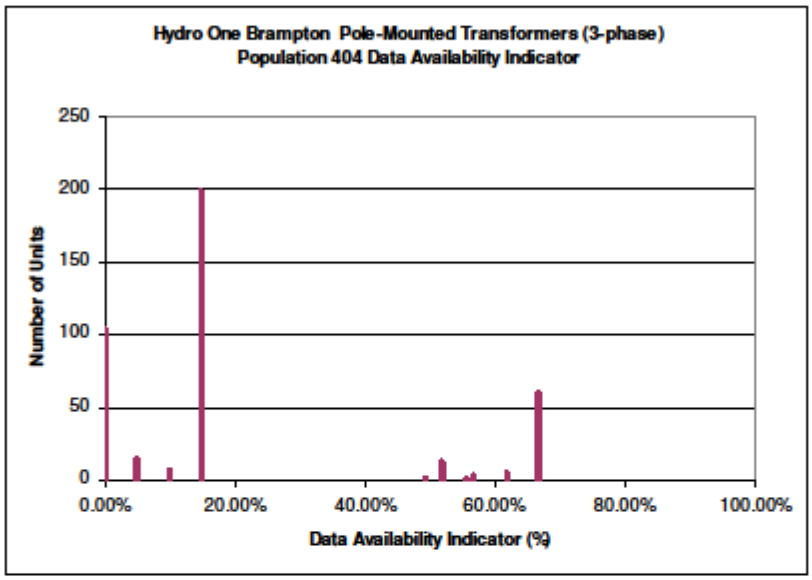


Figure 8-3 Three Phase Pole Mounted Transformers Data Availability Indicator Distribution

8.8 Capital Replacement Plan

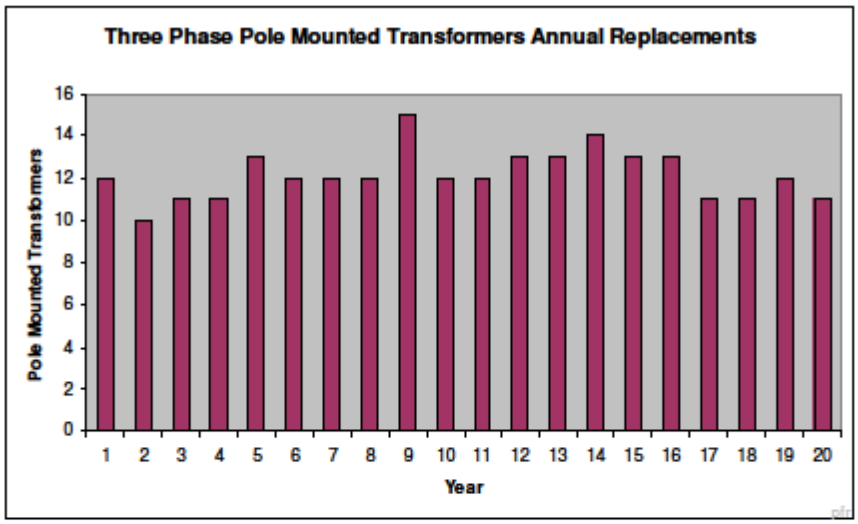


Figure 8-4 Three Phase Pole Mounted Transformers Yearly "Probable Failure" Replacements

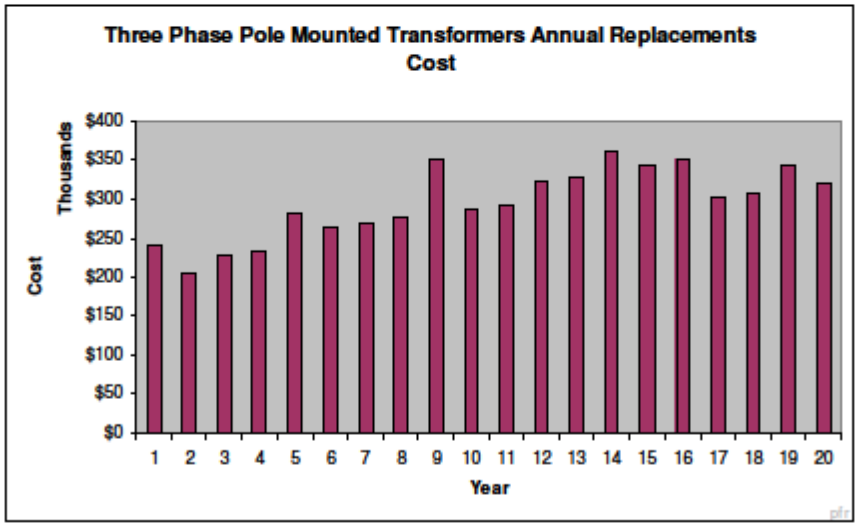


Figure 8-5 Three Phase Pole Mounted Transformers Yearly "Probable Failure" Replacements Cost

8.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset, as the CRP approach is *reactive*.

8.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 87$ and $\beta = 0.055$. The median end of life for pole mounted transformers is 30 years. The maximum end of life is 60 years.

8.11 Data Gap Closure

This section outlines the data gap for distribution transformers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Inspection results (not including submersible transformers)
- PCB
- Age

Data Gap

Type of Data Gap	Priority
Monthly Peak Loading (measurement)	P1
Overall condition (CM)	P1
Corrosion (CM)	P2
IR (measurement)	P1
Access (CM)	P3
Other CM or measurement	P3

9 SINGLE PHASE MINI-PAD TRANSFORMERS

9. SINGLE PHASE MINI-PAD TRANSFORMERS

HOBNI's distribution transformers include single phase mini-pad mounted transformers. There are currently 11331 in use. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid. All of these designs employ sealed tank construction.

9.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

9.2 Health Index Methodology

9.2.1 Health Index Formulation

The generic Health Index formulation for single phase mini-pad mounted transformers is shown below. There was insufficient data to apply the formulas for mini-pad mounted transformers. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m\,max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n\,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

9 SINGLE PHASE MINI-PAD TRANSFORMERS

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 9-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m				$CPS_{m,max}$
		Pad Mounted	Pole Mounted	Submer-sible	Vault	
1	Physical condition	3	1	7	7	4
2	Cooling	5	1	5	5	4
3	Environment	5	3	5	5	4
4	Reliability	5	4	5	5	4

Table 9-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	Corrosion	Table 9-6	3	1	3	3	4
2	Access	Table 9-7	1		1	1	4
3	Base	Table 9-8	2				4
4	Housekeeping	Table 9-10				5	4
Multiplying factor							

Table 9-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	IR scan	Table 9-12	2			2	4
2	Oil leak	Table 9-9	1	1	1	1	4

Table 9-4 Environment (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	PCB	Table 9-13	1	1	1	1	4

Table 9-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	overall	Table 9-11	2	2	2	2	4
2	age	Table 9-14	1	1	1	1	4

9.2.2 Condition Criteria

9.2.2.1 *Individual Condition Based on Site Inspection*

Table 9-6 Corrosion condition

Condition Description	CPF
None	4
Layers	1
Rust	0
Skirt	1
Painting	2
Graffiti	3
Surface	0
Stickers	2

Table 9-7 Access condition

Condition Description	CPF
O.K.	4
Problem	0
Fence	0
Tree/shrub	0

Table 9-8 Base condition

Condition Description	CPF
Good	4
Fair	2
Needs repairs	0

Table 9-9 Oil leak condition

Condition Description	CPF
Oil	0
No	4

Table 9-10 Housekeeping condition

Condition Description	CPF
Cleaning	2
Lighting	3
Other	1
None	4

Table 9-11 Overall condition

Condition Description	CPF
No	4
Follow-up	3
Correct	1
Immediate	0

9.2.2.2 *Individual Condition Based on Measurement*

Table 9-12 IR Scan condition

Condition Description (ΔT)	CPF
0	4
3	3
5	2
10	1
15	0

Table 9-13 PCB condition

Condition Description (ppm)	CPF
0	4
2.01	3
50.01	1
500.01	0

9.2.2.3 *Individual Condition Based on Transformer Intrinsic Characteristics*

Age

Table 9-14 Transformer age (year)

Condition Rating	CPF	Condition Criteria			
		Pad	Pole	Submersible	Vault
A	4	0	0	0	0
B	3	40	30	25	40
C	2	50	50	35	50
D	1	60	60	40	60
E	0	61	61	41	61

9.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for mini-pad mounted transformers:

- About 3-4% are in bad shape, due to corrosion, rust or leaking gasket, mainly in Northeast of town
- Walk about inspections are done prior to assuming ownership from developers
- Corrosion is detected through visual inspection
- Common problem: leakage in the gasket
- When overloaded: pro-actively replaced
- OEB inspection results are available

9.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

In total, 66 single-phase mini-pads were looked at during the visual inspection.

9 SINGLE PHASE MINI-PAD TRANSFORMERS

The results of the field survey are shown on the Table 9-15.

Table 9-15 Mini Pad Transformer Survey

Location / Identifier	Main Cabinet Condition	Pad Condition	Oil Leaks	Operating Temperature	Overall Transformer Condition
[illegible]	D	D	D	2	2
[illegible]	B	B	B	3	3
[illegible]	B	B	B	3	3
[illegible]	B	B	B	3	3
[illegible]	B	B	B	3	3
[illegible]	B	B	B	3	3
Stanley Cranberry (2304)	D	D	D	2	2
[illegible]	B	B	B	3	3
Stanley Cranberry (2316)	D	D	D	2	2
[illegible]	B	B	B	3	3
Della Drive (2315)	D	D	2	2	C
[illegible]	B	B	B	3	3
45 Elenora Cres (3216)	D	2	2	2	C
[illegible]	B	B	B	3	3
[illegible]	B	B	B	3	3
[illegible]	B	B	B	3	3
[illegible]	B	B	B	3	3
[illegible]	B	B	B	3	3

9 SINGLE PHASE MINI-PAD TRANSFORMERS

A summary of the Overall Condition field survey results for single-phase mini-pad transformers is shown on Figure 9-1.

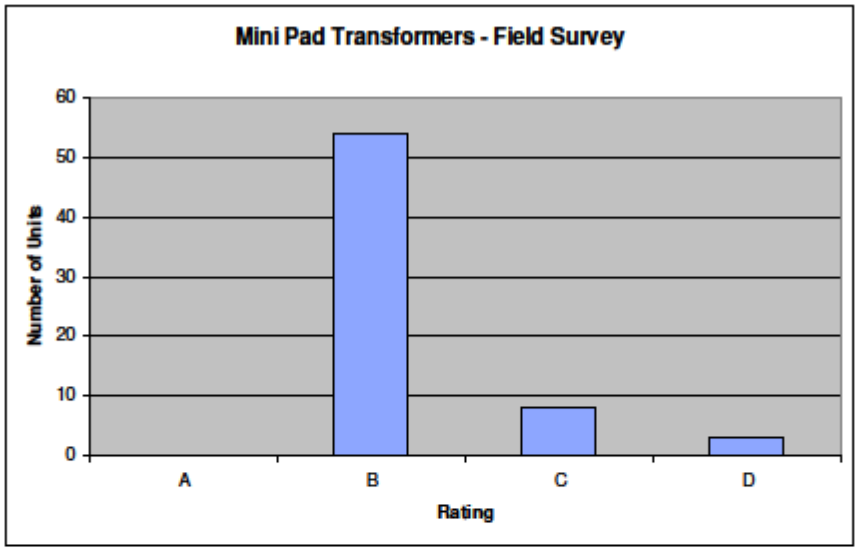


Figure 9-1 Mini-Pad Transformer Field Survey Summary of Overall Condition

9.5 Health Index Distribution

The Health Index distribution is shown below:

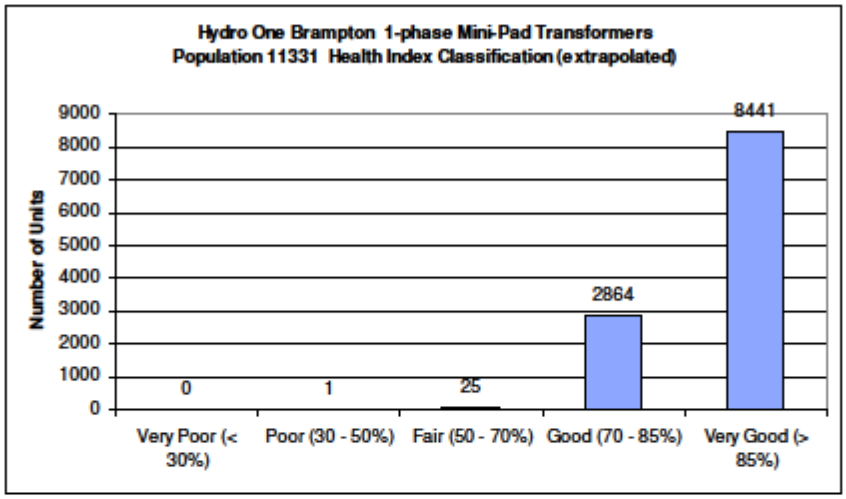


Figure 9-2 Mini-Pad Transformers Health Index Distribution

The assets in the poor/very poor category are:

Classification	Transformer	Cause
Poor	T04612	due to corrosion, rust, and oil leak

9.6 Age Distribution

The age distribution is shown on the figure below:

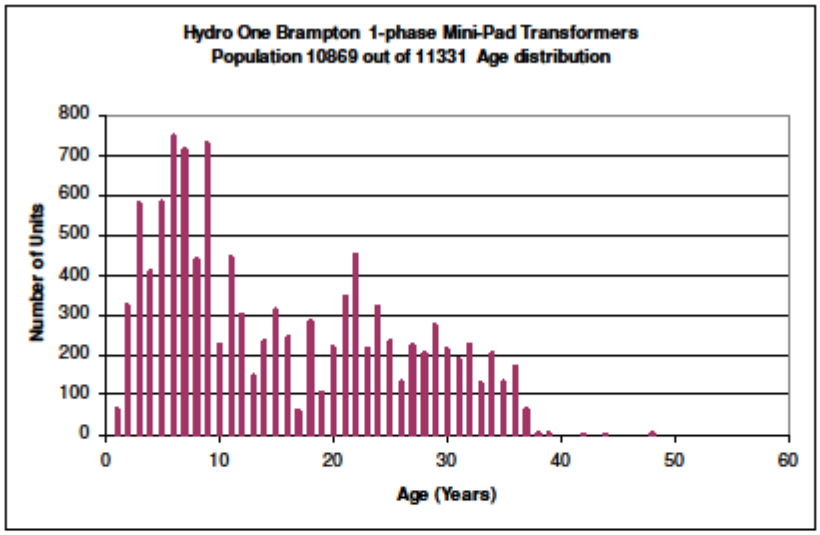


Figure 9-3 Mini-Pad Transformers Age Distribution

9.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

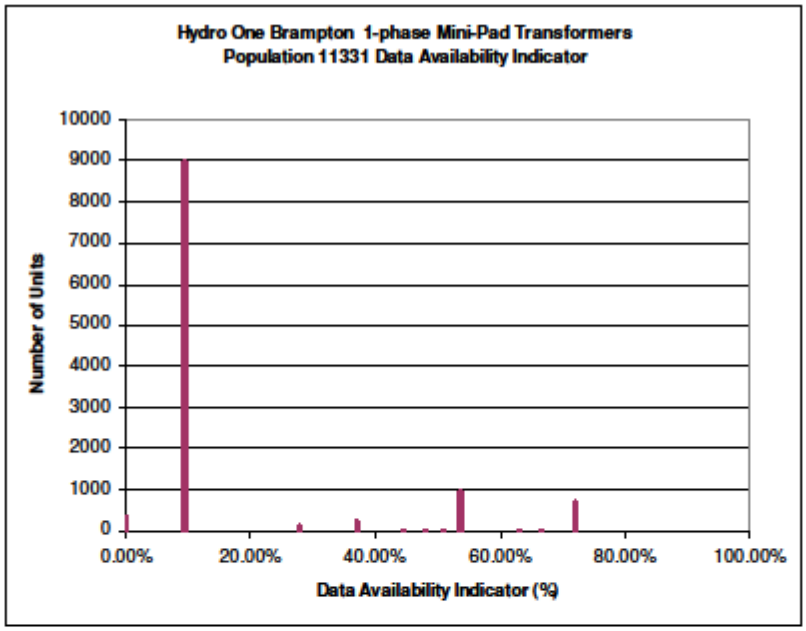


Figure 9-4 Mini-Pad Transformers Data Availability Indicator Distribution

9.8 Capital Replacement Plan

This asset category is a typical minimal risk cost type. The associated cost of failure is the asset replacement cost. Accordingly a probability of failure replacement plan was developed with $\alpha = 72$ and $\beta = 0.089$. In addition:

- The α and β values were adjusted based on HOBNI expert opinion on the usual number of yearly replacements. A fit to 5 years of failure data provided an overly pessimistic (too many replacements) failure curve according to HOBNI staff.
- Population of 11,331 of which 10,869 or 95.9% had data. The remaining 4.1% were extrapolated based on the age distribution.
- Asset costs were either looked up directly or interpolated (based on rating) from HOBNI provided cost data.

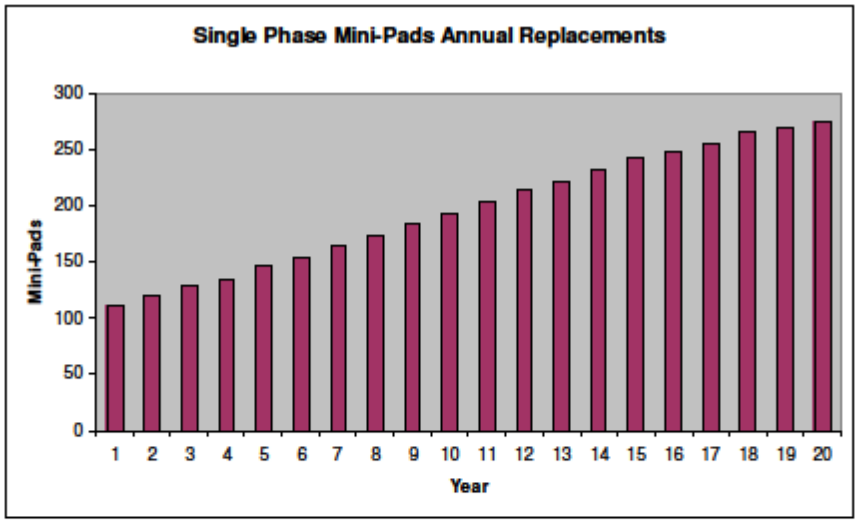


Figure 9-5 Mini-Pad Transformers Yearly "Probable Failure" Replacements

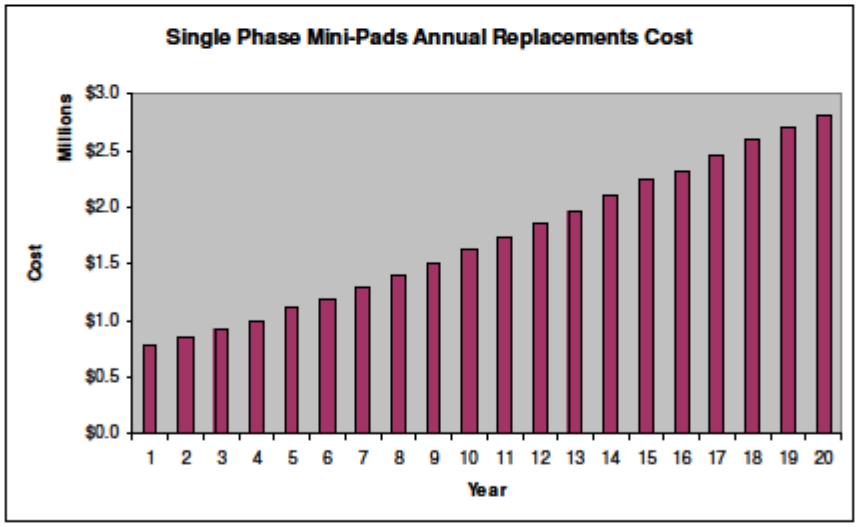


Figure 9-6 Mini-Pad Transformers Yearly "Probable Failure" Replacements Cost

9.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset, as the CRP approach is *reactive*.

9.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 72$ and $\beta = 0.089$. The median end of life for mini-pad transformers is 40 years. The maximum end of life is 60 years.

9.11 Data Gap Closure

This section outlines the data gap for distribution transformers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Inspection results (not including submersible transformers)
- PCB
- Age

Data Gap

Type of Data Gap	Priority
Monthly Peak Loading (measurement)	P1
Overall condition (CM)	P1
Corrosion (CM)	P2
IR (measurement)	P1
Access (CM)	P3
Other CM or measurement	P3

10 THREE PHASE PAD-MOUNTED TRANFORMERS

10. THREE PHASE PAD-MOUNTED TRANFORMERS

HOBNI's distribution transformers include 723 three phase pad-mounted transformers. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid. All of these designs employ sealed tank construction.

10.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

10.2 Health Index Methodology

10.2.1 Health Index Formulation

The generic Health Index formulation for three phase pad mounted transformers is shown below. There was insufficient data to apply the formulas for three phase pad mounted transformers. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m\,max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n\,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

10 THREE PHASE PAD-MOUNTED TRANFORMERS

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 10-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m				$CPS_{m,max}$
		Pad Mounted	Pole Mounted	Submer-sible	Vault	
1	Physical condition	3	1	7	7	4
2	Cooling	5	1	5	5	4
3	Environment	5	3	5	5	4
4	Reliability	5	4	5	5	4

Table 10-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	Corrosion	Table 10-6	3	1	3	3	4
2	Access	Table 10-7	1		1	1	4
3	Base	Table 10-8	2				4
4	Housekeeping	Table 10-10				5	4

Table 10-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	IR scan	Table 10-12	2			2	4
2	Oil leak	Table 10-9	1	1	1	1	4

Table 10-4 Environment (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	PCB	Table 10-13	1	1	1	1	4

Table 10-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	overall	Table 10-11	2	2	2	2	4
2	age	Table 10-14	1	1	1	1	4

10.2.2 Condition Criteria

10.2.2.1 ***Individual Condition Based on Site Inspection***

Table 10-6 Corrosion condition

Condition Description	CPF
None	4
Layers	1
Rust	0
Skirt	1
Painting	2
Graffiti	3
Surface	0
Stickers	2

Table 10-7 Access condition

Condition Description	CPF
O.K.	4
Problem	0
Fence	0
Tree/shrub	0

Table 10-8 Base condition

Condition Description	CPF
Good	4
Fair	2
Needs repairs	0

Table 10-9 Oil leak condition

Condition Description	CPF
Oil	0
No	4

Table 10-10 Housekeeping condition

Condition Description	CPF
Cleaning	2
Lighting	3
Other	1
None	4

Table 10-11 Overall condition

Condition Description	CPF
No	4
Follow-up	3
Correct	1
Immediate	0

10.2.2.2 ***Individual Condition Based on Measurement***

Table 10-12 IR Scan condition

Condition Description (ΔT)	CPF
0	4
3	3
5	2
10	1
15	0

Table 10-13 PCB condition

Condition Description (ppm)	CPF
0	4
2.01	3
50.01	1
500.01	0

10.2.2.3 ***Individual Condition Based on Transformer Intrinsic Characteristics***

Age

Table 10-14 Transformer age (year)

Condition Rating	CPF	Condition Criteria			
		Pad	Pole	Submersible	Vault
A	4	0	0	0	0
B	3	40	30	25	40
C	2	50	50	35	50
D	1	60	60	40	60
E	0	61	61	41	61

10.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for pad mounted transformers:

- Walk about inspections are done prior to assuming ownership from developers
- Corrosion is detected through visual inspection
- OEB inspection results are available

10.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

In total, 40 three-phase pad-mounted transformers were looked at during field inspection. The results of the field survey are shown below on Table 10-15.

Table 10-15 Three Phase Pad Mounted Transformer Survey

Location / Identifier	Main Cabinet Condition	Pad Condition	Oil Leaks	Operating Temperature	Overall Transformer Condition
1701 Queen E (9543)	D	D	C	D	D
1625 Queen E (7545)	B	C	F	B	B
253 Elmwood (6138)	C	D	L	U	D
92 Fernbank (10166)	B	B	F	B	B
17 Kings Grove rd (9456)	C	B	E	B	B
175 Central Park Dr (7462)	C	C	F	B	B
14 Kingsbridge rd (9926)	B	B	E	B	B
7 Sunny [illegible] (2744)	C	B	F	B	B
999 Peel Substation (10733)	B	L	E	B	B
1920 North Park (9780)	B	B	F	B	B
9550 Torbram (9450)	B	B	E	B	B
91 Deer Forest (7747)	D	D	C	D	D
1775 Queen E (9554)	C	B	E	B	B
15 East Drive Drive (7058)	D	C	C	D	D
57 East Avenue Ct (7008)	B	B	E	B	B
702 Elmwood (7078)	A	A	A	A	A
38 Finchgate (11266)	B	B	E	B	B
105 East Drive (10111)	D	D	C	D	D
30 Presidio Crt (11567)	A	A	A	A	A
7 McClair (1633)	C	D	C	D	D

Location / Identifier	Main Cabinet Condition	Pad Condition	Oil Leaks	Operating Temperature	Overall Transformer Condition
10310	D	A	A	D	D
19690	C	A	A	A	B
10122	C	D	A	D	D
19995	B	B	A	D	B
11702	D	A	D	D	D
19994	B	A	A	A	B
12303	B	B	A	E	B
19629	B	B	A	F	B
970	C	B	A	D	C
11191	B	B	A	F	B
12802	D	B	A	A	C
914	C	D	A	F	D
11972	B	B	A	E	B
12250	D	A	A	C	D
507	C	B	A	D	B
4936	D	C	A	D	D
6718	D	B	D	D	D
2787	D	D	A	A	D
7621	C	B	C	E	C
4141	C	D	C	D	D

10 THREE PHASE PAD-MOUNTED TRANFORMERS

The site survey ratings are summarized on Table 10-16.

Table 10-16 Summary of Three Phase Pad Mounted Transformer Ratings

	#A	#B	#C	#D
Main Cabinet Condition	2	21	13	4
Pad Condition	7	28	3	0
Oil Leaks	18	18	2	0
Operating Temperature	6	25	0	0
Overall Transformer Condition	2	32	4	2
Sum	35	124	22	6
% of Known	18.7%	66.3%	11.8%	3.2%

The site survey ratings of Overall Transformer Condition are summarized as follows:

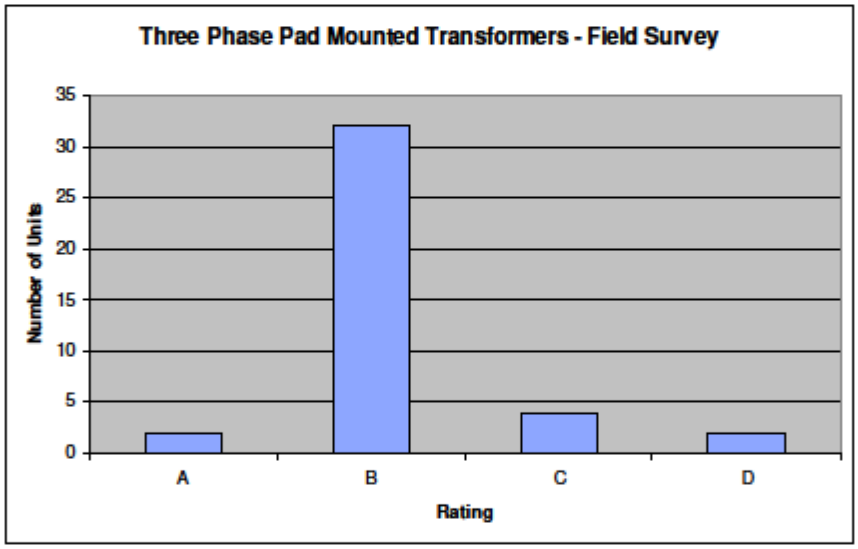


Figure 10-1 Three Phase Pad Mounted Transformers - Field Survey Summary of Overall Condition

10.5 Health Index Distribution

The Health Index distribution is shown on the figure below:

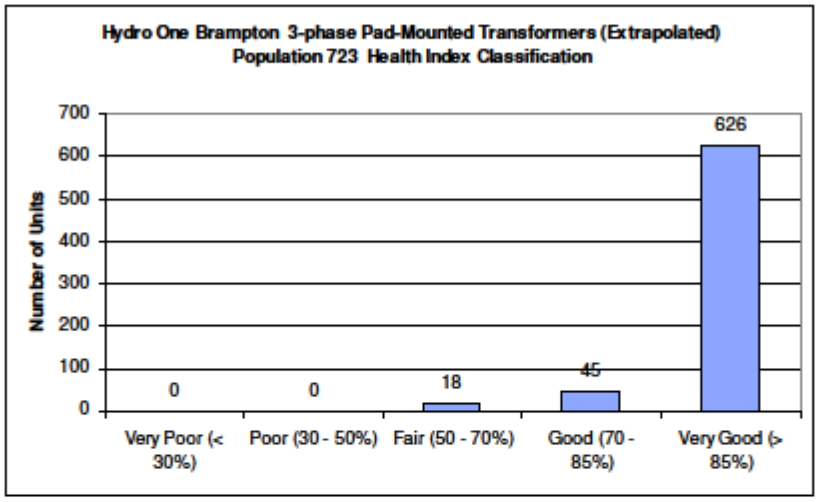


Figure 10-2 Three Phase Pad-Mounted Transformers Health Index Distribution

10.6 Age Distribution

The age distribution is shown on the figure below:

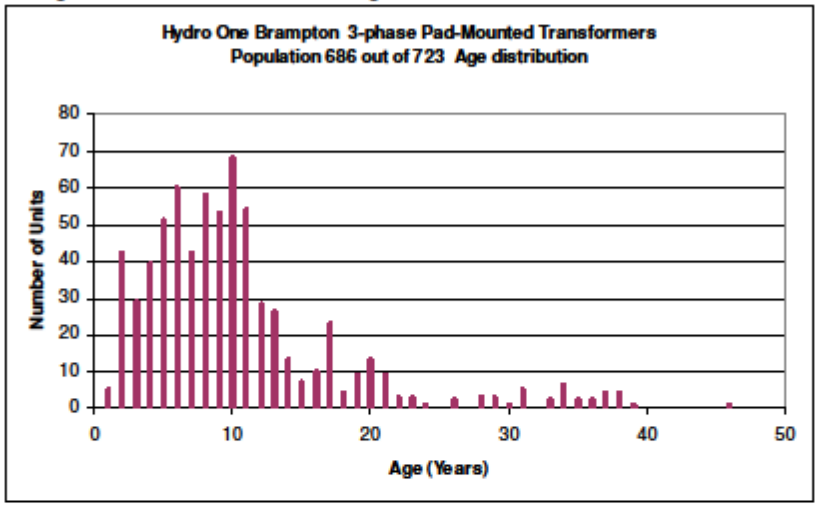


Figure 10-3 Three Phase Pad-Mounted Transformers Age Distribution

10.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

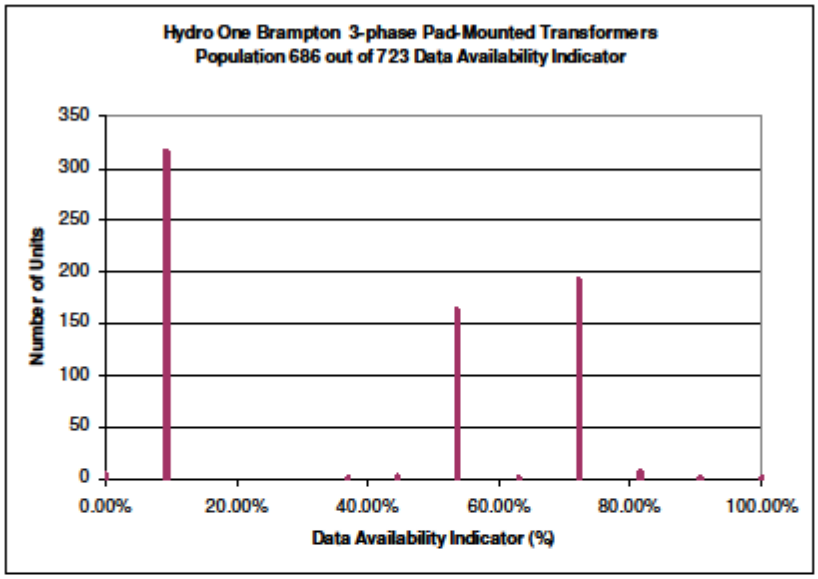


Figure 10-4 Three Phase Pad-Mounted Transformers Data Availability Indicator Distribution

10.8 Capital Replacement Plan

This asset category is a typical minimal risk cost type. The associated cost of failure is the asset replacement cost. Accordingly a probability of failure replacement plan was developed with $\alpha = 62$ and $\beta = 0.088$. In addition:

- Population of 723 of which 694 or 96.0% had data. The remaining 4% were extrapolated based on the age distribution.
- Asset costs were either looked up directly or interpolated (based on rating) from HOBNI provided cost data.
- Units are assumed to be single phase replacements and the quoted 3 phase replacement costs have been divided up accordingly.
- Because the replacements are based on probability of failure for each year, given the age distribution of the asset, no levelizing of the yearly replacement costs is possible.

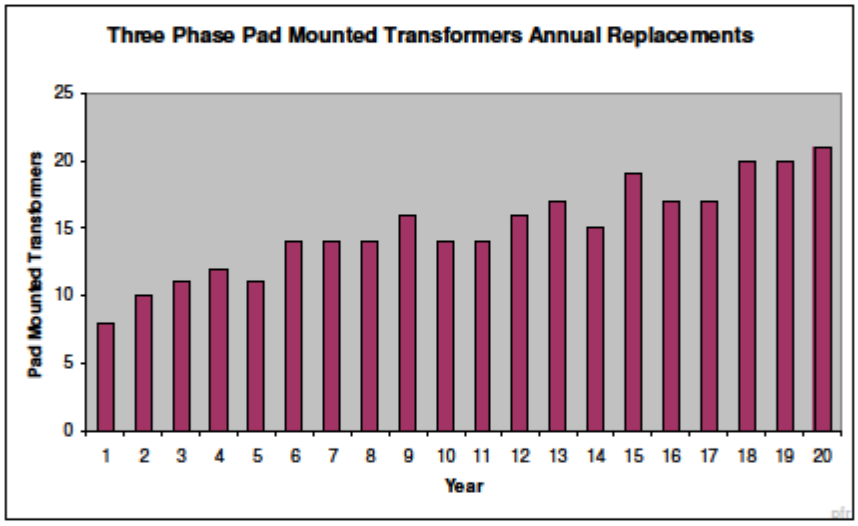


Figure 10-5 Three Phase Pad-Mounted Transformers Yearly "Probable Failure" Replacements

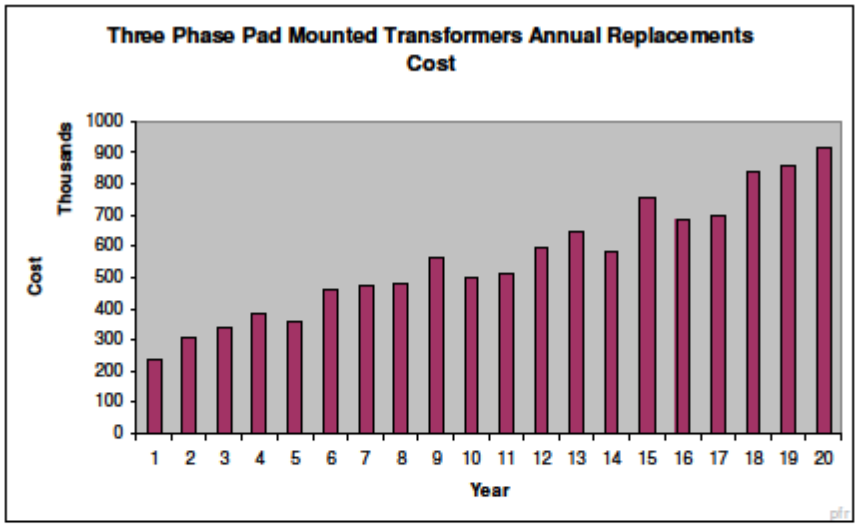


Figure 10-6 Three Phase Pad-Mounted Transformers Yearly "Probable Failure" Replacements Cost

10.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset, as the CRP approach is *reactive*.

10.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 62$ and $\beta = 0.088$. The median end of life for three phase pad mounted transformers is 30 years. The maximum end of life is 50 years.

10.11 Data Gap Closure

This section outlines the data gap for distribution transformers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Inspection results (not including submersible transformers)
- PCB
- Age

Data Gap

Type of Data Gap	Priority
Monthly Peak Loading (measurement)	P1
Overall condition (CM)	P1
Corrosion (CM)	P2
IR (measurement)	P1
Access (CM)	P3
Other CM or measurement	P3

11 SUBMERSIBLE TRANSFORMER

11. SUBMERSIBLE TRANSFORMER

HOBNI's distribution transformers include 151 submersible transformers. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid. All of these designs employ sealed tank construction.

11.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

11.2 Health Index Methodology

11.2.1 Health Index Formulation

The generic Health Index formulation for submersible transformers is shown below. There was insufficient data to apply the formulas for submersible transformers. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m,max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

11 SUBMERSIBLE TRANSFORMER

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 11-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m				$CPS_{m,max}$
		Pad Mounted	Pole Mounted	Submer-sible	Vault	
1	Physical condition	3	1	7	7	4
2	Cooling	5	1	5	5	4
3	Environment	5	3	5	5	4
4	Reliability	5	4	5	5	4

Table 11-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	Corrosion	Table 11-6	3	1	3	3	4
2	Access	Table 11-7	1		1	1	4
3	Base	Table 11-8	2				4
4	Housekeeping	Table 11-10				5	4

Table 11-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	IR scan	Table 11-12	2			2	4
2	Oil leak	Table 11-9	1	1	1	1	4

Table 11-4 Environment (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	PCB	Table 11-13	1	1	1	1	4

Table 11-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	overall	Table 11-11	2	2	2	2	4
2	age	Table 11-14	1	1	1	1	4

11.2.2 Condition Criteria

11.2.2.1 ***Individual Condition Based on Site Inspection***

Table 11-6 Corrosion condition

Condition Description	CPF
None	4
Layers	1
Rust	0
Skirt	1
Painting	2
Graffiti	3
Surface	0
Stickers	2

Table 11-7 Access condition

Condition Description	CPF
O.K.	4
Problem	0
Fence	0
Tree/shrub	0

Table 11-8 Base condition

Condition Description	CPF
Good	4
Fair	2
Needs repairs	0

Table 11-9 Oil leak condition

Condition Description	CPF
Oil	0
No	4

Table 11-10 Housekeeping condition

Condition Description	CPF
Cleaning	2
Lighting	3
Other	1
None	4

Table 11-11 Overall condition

Condition Description	CPF
No	4
Follow-up	3
Correct	1
Immediate	0

11.2.2.2 ***Individual Condition Based on Measurement***

Table 11-12 IR Scan condition

Condition Description (ΔT)	CPF
0	4
3	3
5	2
10	1
15	0

Table 11-13 PCB condition

Condition Description (ppm)	CPF
0	4
2.01	3
50.01	1
500.01	0

11.2.2.3 ***Individual Condition Based on Transformer Intrinsic Characteristics***

Age

Table 11-14 Transformer age (year)

Condition Rating	CPF	Condition Criteria			
		Pad	Pole	Submersible	Vault
A	4	0	0	0	0
B	3	40	30	25	40
C	2	50	50	35	50
D	1	60	60	40	60
E	0	61	61	41	61

11.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for submersible transformers:

- Major issues are corrosion and switching
- Majority of population are in Bramalea area, some in old Brampton

11.4 Field Surveys

A field survey was not conducted on this asset.

11.5 Health Index Distribution

The Health Index distribution is shown on the figure below:

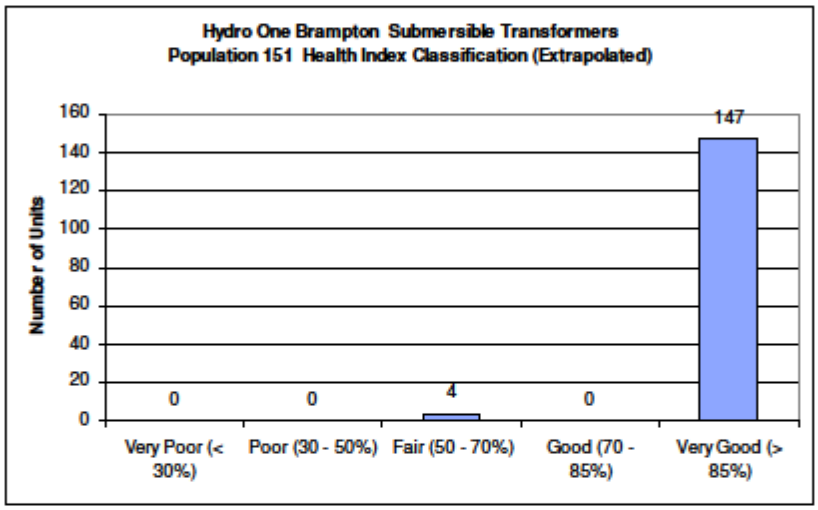


Figure 11-1 Submersible Transformers Health Index Distribution

11.6 Age Distribution

The age distribution is shown on the figure below:

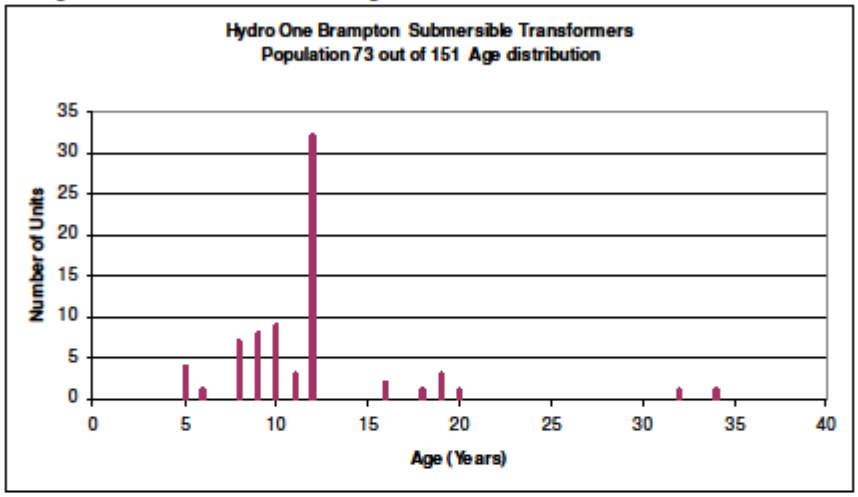


Figure 11-2 Submersible Transformers Age Distribution

11.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

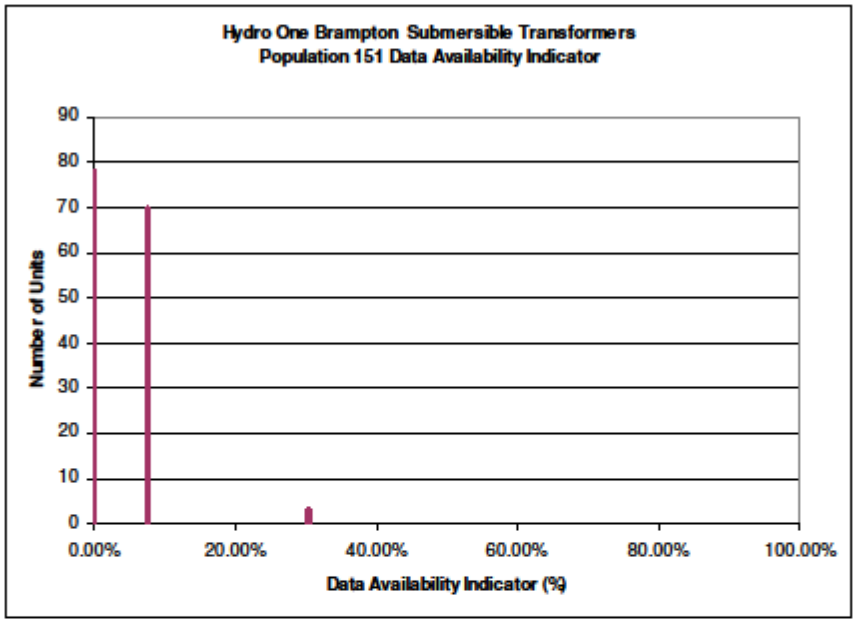


Figure 11-3 Submersible Transformers Data Availability Index Distribution

11.8 Optimal Capital Replacement Plan

This asset category is a typical minimal risk cost type. The associated cost of failure is the asset replacement cost. Accordingly a probability of failure replacement plan was developed with $\alpha = 48$ and $\beta = 0.112$. In addition:

- Population of 151 of which 73 or 48% had data. The remaining 52% were extrapolated based on the age distribution.
- Asset costs were either looked up directly or interpolated (based on rating) from HOBNI provided cost data.
- Because the replacements are based on probability of failure for each year, given the age distribution of the asset, no levelizing of the yearly replacement costs is possible.

11 SUBMERSIBLE TRANSFORMER

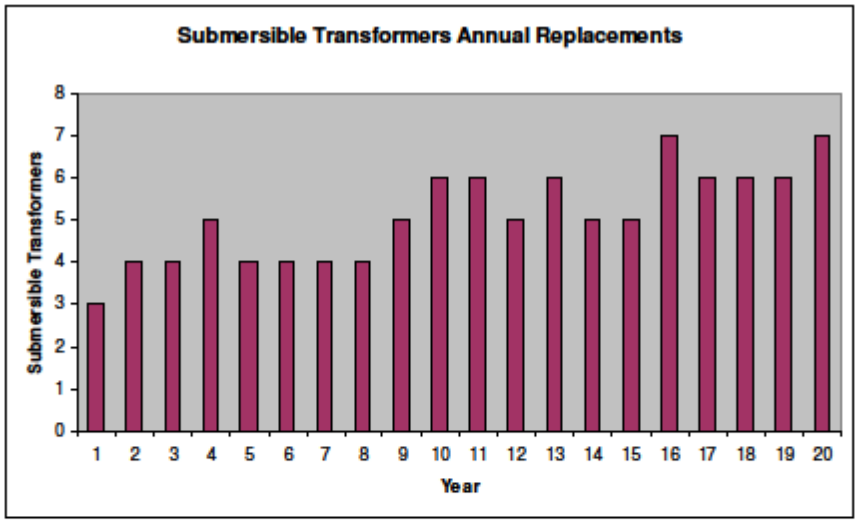


Figure 11-4 Submersible Transformers Yearly "Probable Failure" Replacements

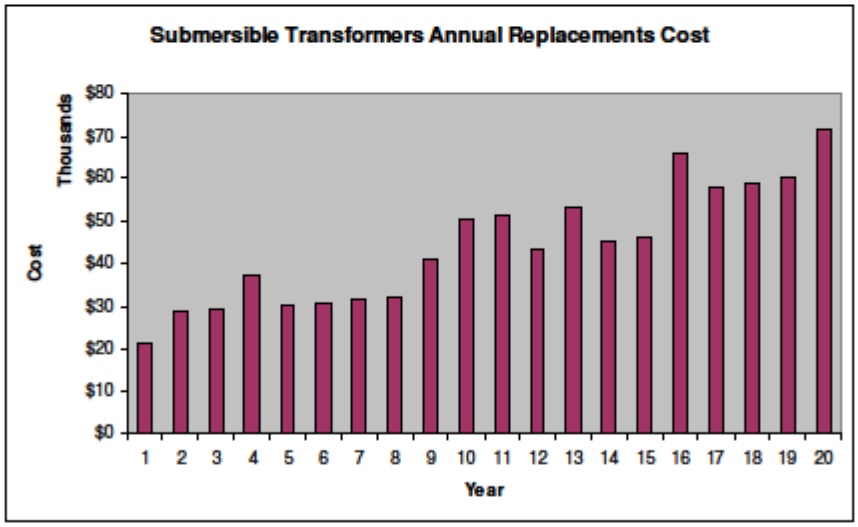


Figure 11-5 Submersible Transformers Yearly "Probable Failure" Replacements Cost

11.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset, as the CRP approach is *reactive*.

11.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 48$ and $\beta = 0.112$. The median end of life for submersible transformers is 25 years. The maximum end of life is 40 years.

11.11 Data Gap Closure

This section outlines the data gap for distribution transformers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Inspection results (not including submersible transformers)
- PCB
- Age

Data Gap

Type of Data Gap	Priority
Monthly Peak Loading (measurement)	P1
Overall condition (CM)	P1
Corrosion (CM)	P2
IR (measurement)	P1
Access (CM)	P3
Other CM or measurement	P3

11 SUBMERSIBLE TRANSFORMER

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12 VAULT TRANSFORMERS

12. VAULT TRANSFORMERS

HOBNI's distribution transformers include 1447 vault transformers. A majority of these transformers are liquid filled, with mineral insulating oil being the predominant liquid. All of these designs employ sealed tank construction. It is worth noting that the condition assessment for this asset group is for the transformers only and not the structures housing them.

12.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the

end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

12.2 Health Index Methodology

12.2.1 Health Index Formulation

The generic Health Index formulation for vault transformers is shown below. There was insufficient data to apply the formulas for vault transformers. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m,max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

12 VAULT TRANSFORMERS

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 12-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m				$CPS_{m,max}$
		Pad Mounted	Pole Mounted	Submer-sible	Vault	
1	Physical condition	3	1	7	7	4
2	Cooling	5	1	5	5	4
3	Environment	5	3	5	5	4
4	Reliability	5	4	5	5	4

Table 12-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	Corrosion	Table 12-6	3	1	3	3	4
2	Access	Table 12-7	1		1	1	4
3	Base	Table 12-8	2				4
4	Housekeeping	Table 12-10				5	4

Table 12-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	IR scan	Table 12-12	2			2	4
2	Oil leak	Table 12-9	1	1	1	1	4

Table 12-4 Environment (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	PCB	Table 12-13	1	1	1	1	4

Table 12-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$				$CPF_{n,max}$
			Pad	Pole	Sub	Vault	
1	overall	Table 12-11	2	2	2	2	4
2	age	Table 12-14	1	1	1	1	4

12.2.2 Condition Criteria

12.2.2.1 ***Individual Condition Based on Site Inspection***

Table 12-6 Corrosion condition

Condition Description	CPF
None	4
Layers	1
Rust	0
Skirt	1
Painting	2
Graffiti	3
Surface	0
Stickers	2

Table 12-7 Access condition

Condition Description	CPF
O.K.	4
Problem	0
Fence	0
Tree/shrub	0

Table 12-8 Base condition

Condition Description	CPF
Good	4
Fair	2
Needs repairs	0

Table 12-9 Oil leak condition

Condition Description	CPF
Oil	0
No	4

Table 12-10 Housekeeping condition

Condition Description	CPF
Cleaning	2
Lighting	3
Other	1
None	4

Table 12-11 Overall condition

Condition Description	CPF
No	4
Follow-up	3
Correct	1
Immediate	0

12.2.2.2 ***Individual Condition Based on Measurement***

Table 12-12 IR Scan condition

Condition Description (ΔT)	CPF
0	4
3	3
5	2
10	1
15	0

Table 12-13 PCB condition

Condition Description (ppm)	CPF
0	4
2.01	3
50.01	1
500.01	0

12.2.2.3 ***Individual Condition Based on Transformer Intrinsic Characteristics***

Age

Table 12-14 Transformer age (year)

Condition Rating	CPF	Condition Criteria			
		Pad	Pole	Submersible	Vault
A	4	0	0	0	0
B	3	40	30	25	40
C	2	50	50	35	50
D	1	60	60	40	60
E	0	61	61	41	61

12.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for vault transformers:

- Investigative replacement program underway for possible replacement of 16 building vault transformers: where it is possible these will be replaced with pad mounts outside of the building: unsafe vault though transformers not too bad
- 1-2% have oil leaking problem
- The major issue is insulator flashover or fuse blown due to contamination
- 2400 V units are old (20-40 years)
- Replacement program for replacing secondary network downtown
- OEB inspection results are available

12.4 Field Surveys

A field survey was not conducted on this asset.

12.5 Health Index Distribution

The Health Index distribution is shown on the figure below:

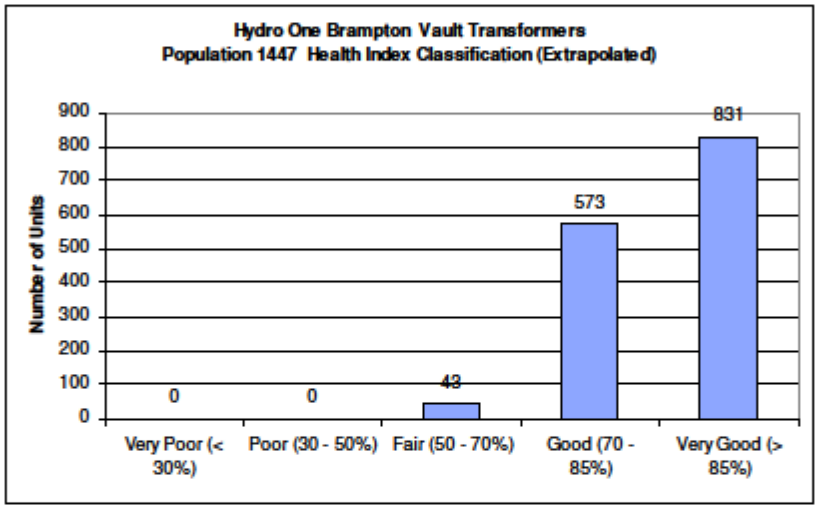


Figure 12-1 Vault Transformers Health Index Distribution

12.6 Age Distribution

The age distribution is shown on the figure below:

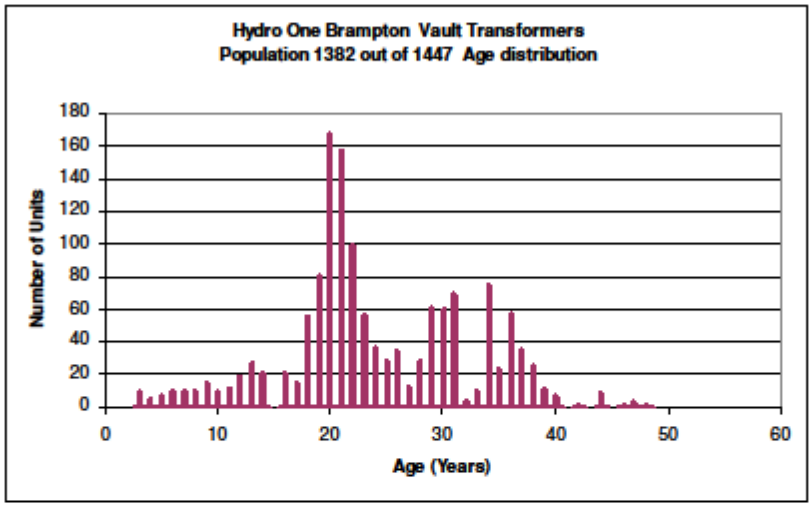


Figure 12-2 Vault Transformers Age Distribution

12.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

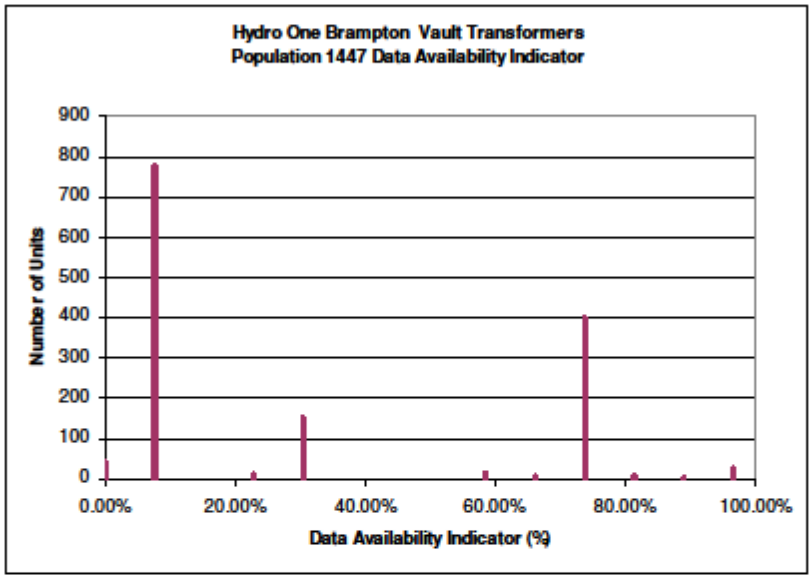


Figure 12-3 Vault Transformers Data Availability Index Distribution

12.8 Capital Replacement Plan

This asset category is a typical minimal risk cost type. The associated cost of failure is the asset replacement cost. Accordingly a probability of failure replacement plan was developed with $\alpha = 72$ and $\beta = 0.089$. In addition:

- Population of 1447 of which 1313 or 91% had data. The remaining 9% were extrapolated based on the age distribution.
- Asset costs were either looked up directly or interpolated (based on rating) from HOBNI provided cost data.
- Because the replacements are based on probability of failure for each year, given the age distribution of the asset, no levelizing of the yearly replacement costs is possible.

12 VAULT TRANSFORMERS

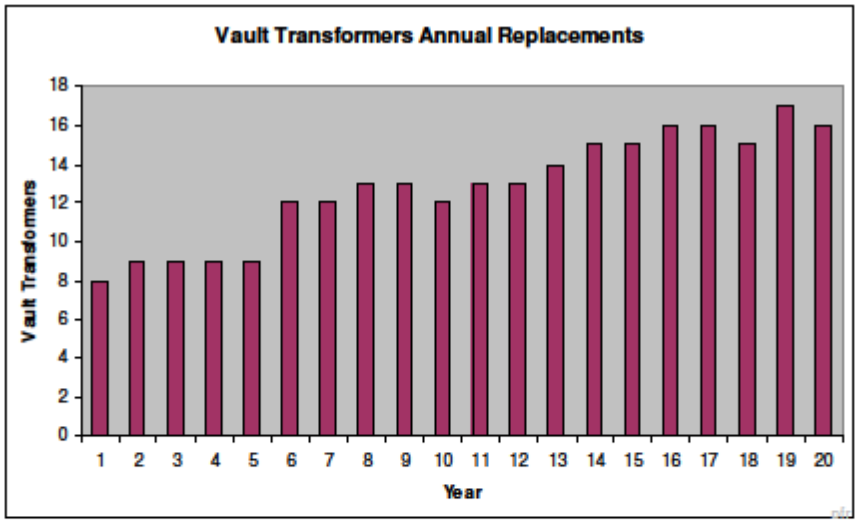


Figure 12-4 Vault Transformers Yearly "Probable Failure" Replacements

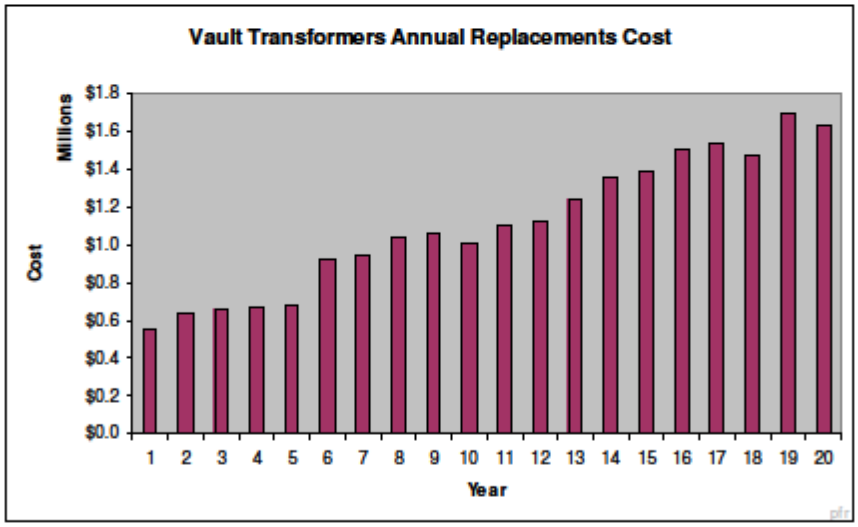


Figure 12-5 Vault Transformers Yearly "Probable Failure" Replacements Cost

12.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset, as the CRP approach is *reactive*.

12.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 72$ and $\beta = 0.089$. The median end of life for vault transformers is 40 years. The maximum end of life is 60 years.

12.11 Data Gap Closure

This section outlines the data gap for distribution transformers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Inspection results (not including submersible transformers)
- PCB
- Age

Data Gap

Type of Data Gap	Priority
Monthly Peak Loading (measurement)	P1
Overall condition (CM)	P1
Corrosion (CM)	P2
IR (measurement)	P1
Access (CM)	P3
Other CM or measurement	P3

12 VAULT TRANSFORMERS

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13 LOAD INTERRUPTING SWITCHES

13. LOAD INTERRUPTING SWITCHES

Hydro One Brampton Networks Inc. currently employs about 695 three phase load interrupter overhead switches. This asset group consists of distribution overhead line three-phase gang operated switches, manually operated as well as motor operated. The primary function of switches is to permit isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of switches are rated for load interruption, others are designed to operate under no load conditions, these switches operate only when the current through the switch is zero. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in the open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. The operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

13.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Non-functioning padlocks
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions where the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

The condition assessment of overhead switches involve visual inspections which would reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots.

13 LOAD INTERRUPTING SWITCHES

The following parameters are considered in establishing the asset health:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Operating age of disconnect switch
- Loading profile

The average life expectancy of overhead switches is approximately 40 years. Consequences of overhead line switch failure may include customer interruption and health and safety issues for operators.

13.2 Health Index Methodology

13.2.1 Health Index Formulation

The generic Health Index formulation for overhead switches is shown below. There was insufficient data to apply the formulas for overhead switches. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{5} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m\,max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n\,max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

13 LOAD INTERRUPTING SWITCHES

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 13-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m,max}$
1	Operating mechanism	**14**	4
2	Contact performance	**7**	4
3	Arc extinction	**5**	4
4	Insulation	**2**	4
5	Reliability	**7**	4

Table 13-2 Operating Mechanism (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table (in Appendix part)	$WCPF_n$	$CPF_{n,max}$
1	Mechanism (cm)	Table 13-7	9	4
2	Mechanical support (cm)	Table 13-7	1	4
	Multiplying factor	Table 13-11	For air-insulated type only	

(cm) –- Corrective maintenance record

Table 13-3 Contact Performance (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table (in Appendix part)	$WCPF_n$	$CPF_{n,max}$
1	Contact (cm)	Table 13-7	1	4

Table 13-4 Arc Extinction (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table (in Appendix part)	$WCPF_n$	$CPF_{n,max}$
1	Tank/Bottle (cm)	Table 13-7	1	4
	Multiplying factor	Table 13-11	For vacuum-insulated type only	

(cm) –- Corrective maintenance record

Table 13-5 Insulation (m=4) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table (in Appendix part)	$WCPF_n$	$CPF_{n,max}$
1	Insulator (cm)	Table 13-7	1	4

(cm) –- Corrective maintenance record

Table 13-6 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table (in Appendix part)	$WCPF_n$	$CPF_{n,max}$
1	Failure factor	Table 13-9	3	4
2	Age	Table 13-8	1	4

13.2.2 Condition Criteria

13.2.2.1 Individual Condition Based on Corrective Maintenance (CM) Record

A corrective maintenance work order implies that something was detected that required action. For a breaker in good condition, there should not be any such work orders.

However, on occasion, a deficiency is detected which requires action. It is assumed that once the action takes place, the asset is returned to good or 'as-new' condition. Repeated CM WOs (corrective maintenance work orders) for the same reason implies that some underlying problem and is indicative of poor condition of the asset. For the number of CM actions in the past year, the following condition criteria are proposed.

Table 13-7 Individual condition (closed CM)

Condition Rating	Factor	Condition Description
A	4	No CM work orders in past year
B	3	1 CM work order in past year
C	2	2 CM work orders in past year
D	1	> 2 CM work orders in past year
E	0	Problem cannot be corrected

13.2.2.2 Individual Condition Based on Switch Intrinsic Characters

Age

Table 13-8 Switch age (year)

Condition Rating	Factor	Condition Description
A	4	0-19
B	3	20-39
C	2	40-49
D	1	50-59
E	0	>=60

13.2.2.3 Individual Condition Based on Operation Mode

Failure Factor

Table 13-9 Failure factor

Condition Rating	Factor	Condition Description (F*)
A	4	0
B	3	0.122
C	2	0.244
D	1	0.305
E	0	0.366

* F= age * 0.0061 (failure per unit year, per IEEE industrial survey)

Loading History

Table 13-10 Loading history

Data: S1, S2, S3, ..., SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Factor of Load= $\frac{NA\times 4+NB\times 3+NC\times 2+ND\times 1}{N}$
Note: If there are 2 numbers greater than 1.5, then the "Factor of Load" should be multiplied by 0.6 to show the effect of overheating.

13.2.2.4 ***Expert Opinion***

Table 13-11 Expert opinion

switch type	De-rating multiplier
air-insulated	0.6

13.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for overhead switches:

- Problems with gang-operated air-insulated 44 kV switches, both manually and remotely operated: linkage is not tight enough and results in uneven opening/closing
- For manually operated switches, the other main issue is the arc snuffer problem.
- The manually operated switches are in good condition in general
- For remotely-operated 44 kV switches the motors do not have enough torque to overcome resistance in switch linkage due to infrequent operation

13.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

The results of the field survey for remotely operated units are shown below:

Table 13-12 Remotely Operated Pole Mounted Load Interrupting Switches Survey

Remotely Operated Pole Mounted Load Interrupting Switch Location	Chingacousy/Flowertown	230 Steeles Ave. W.	7935 Kennedy Rd.	Bramalea Rd at MS18	Kennedy/Sandalwood
Insulator Condition	B	A	B	B	B
Mechanical Support Condition	B	A	B	B	B
Signs of Over Heating?	A	A	A	A	A
Contact Condition	U	A	B	B	B
Operating Mechanism Condition	U	A	B	B	B
Motor Operator and Control Condition	C	A	B	D	B
Overall Condition	B	A	B	B	B

13 LOAD INTERRUPTING SWITCHES

The site survey ratings for remotely operated units are summarized as follows:

Table 13-13 Summary of Remotely Operated Pole Mounted Load Interrupting Switches

	#A	#B	#C	#D
Insulator Condition	1	4	0	0
Mechanical Support Condition	1	4	0	0
Signs of Over Heating?	5	0	0	0
Contact Condition	1	3	0	0
Operating Mechanism Condition	1	3	0	0
Motor Operator and Control Condition	1	2	1	1
Overall Condition	1	4	0	0
Sum	11	20	1	1
% of Known	33.3%	60.6%	3.0%	3.0%

The results of the field survey for manually operated units are shown below:

Table 13-14 Manually Operated Pole Mounted Load Interrupting Switches Survey

Manually Operated Pole Mounted Load Interrupting Switch Location	1272 Queen St	McLaughlin/Kingnoll	Marsden & Cornwall	Torbram & Williams Pkwy	Mayfield / Dixie
Insulator Condition	B	B	B	B	A
Mechanical Support Condition	B	C	B	B	A
Signs of Over Heating?	A	A	A	A	A
Contact Condition	U	B	B	B	A
Operating Mechanism Condition	B	B	N	B	A
Overall Condition	B	B	B	B	A

The site survey ratings for manually operated units are summarized as follows:

Table 13-15 Summary of Manually Operated Pole Mounted Interrupting Switches Ratings

	#A	#B	#C	#D
Insulator Condition	1	4	0	0
Mechanical Support Condition	1	3	1	0
Signs of Over Heating?	5	0	0	0
Contact Condition	1	3	0	0
Operating Mechanism Condition	1	3	0	0
Overall Condition	1	4	0	0
Sum	10	17	1	0
% of Known	35.7%	60.7%	3.6%	0.0%

13.5 Health Index Distribution

The Health Index distribution is shown on the figure below:

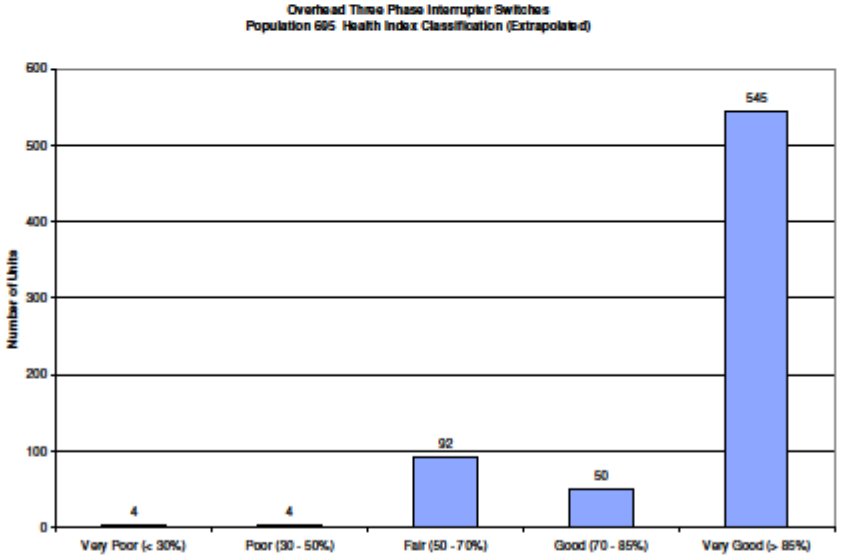


Figure 13-1 Overhead Switches Health Index Distribution

13.6 Age Distribution

The age distribution is shown on the figure below:

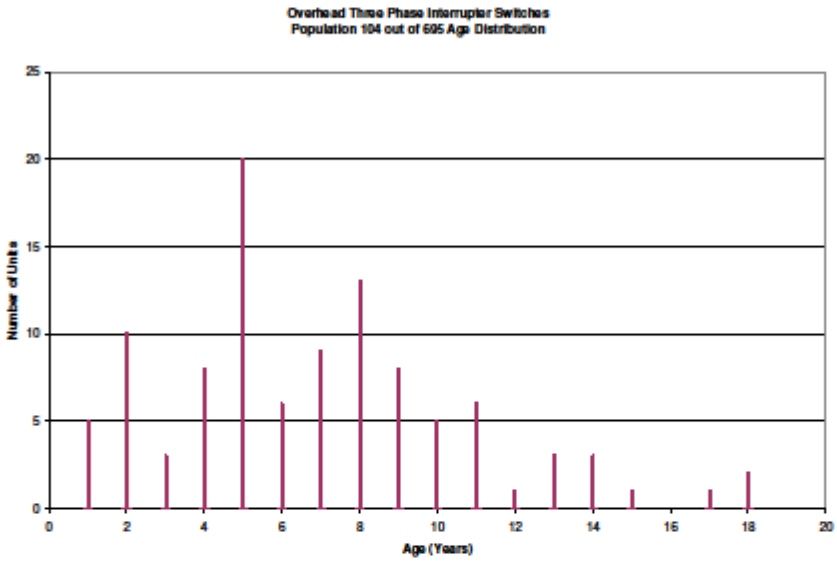


Figure 13-2 Overhead Switches Age Distribution

13.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

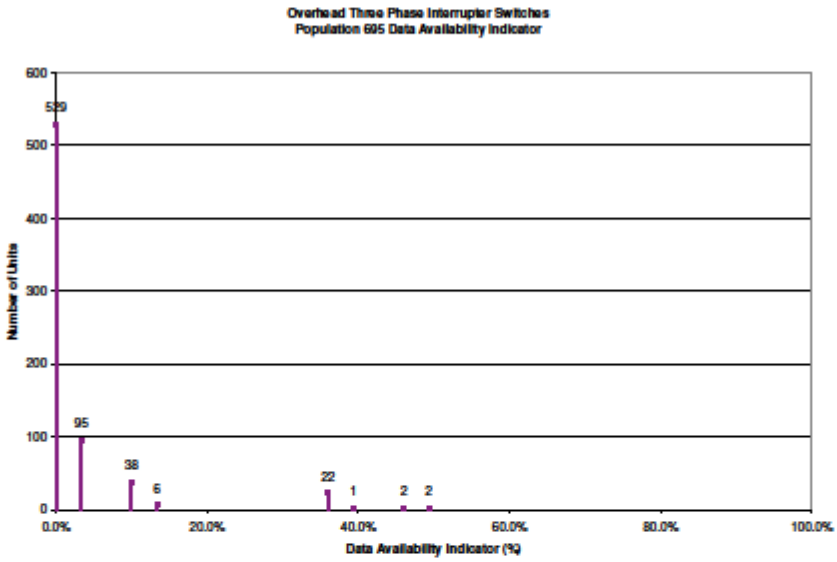


Figure 13-3 Overhead Switches Data Availability Indicator Distribution

13.8 Capital Replacement Plan

This asset category is a typical minimal risk cost type. The associated cost of failure is the asset replacement cost. Accordingly a probability of failure replacement plan was developed with $\alpha = 54$ and $\beta = 0.164$. In addition:

- Population of 695 of which 104 or 15% had data. The remaining 85% were extrapolated based on the age and switch type distribution.
- Asset costs were either looked up directly or interpolated (based on rating) from HOBNI provided cost data.
- Because the replacements are based on probability of failure for each year, given the age distribution of the asset, no levelizing of the yearly replacement costs is possible.

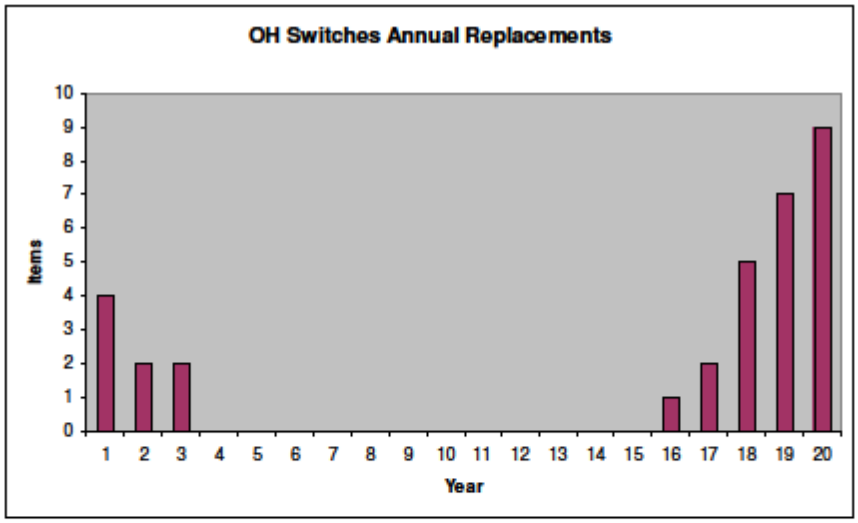


Figure 13-4 Overhead Switches Yearly "Probable Failure" Replacements

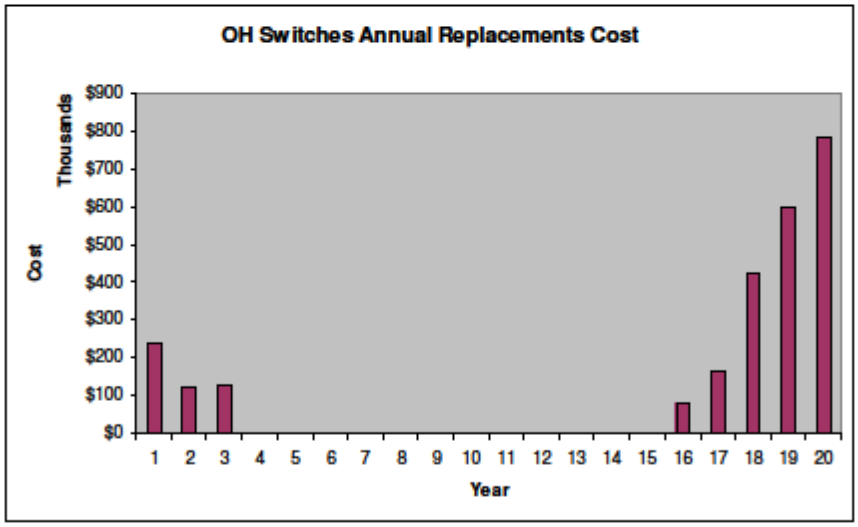


Figure 13-5 Overhead Switches Yearly "Probable Failure" Replacement Cost

13.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset, as the CRP approach is *reactive*.

13.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 54$ and $\beta = 0.164$. The median end of life for overhead switches is 40 years. The maximum end of life is 50 years.

13.11 Data Gap Closure

This section outlines the data gap for overhead switches, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Failure record
- Age

Data Gap

Type of Data Gap	Priority
Mechanism (CM)	P1
Contact (CM)	P2
Tank/bottle (CM)	P2
Insulator (CM)	P2
Other CM or measurement	P3

14 PAD-MOUNTED SWITCHGEAR

14. PAD-MOUNTED SWITCHGEAR

This asset class consists of pad-mounted and above grade switchgear. A majority of the pad mounted switchgear currently in use employs air-insulated gang-operated load-break switches. Hydro One Brampton Networks Inc. currently has 286 pad-mounted switchgears.

14.1 Degradation Mechanism

The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures, ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism or degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site. On an average, the pad mounted switchgear, when maintained regularly can be expected to provide a service life of 30 to 35 years.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO_2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

There are other visually detectable defects that are important and require intervention, but do not result into a failure and can be rectified by field action. For example, graffiti on pad-mounted switchgear is often considered an eyesore and may even conceal important safety and operating signage. Re-painting the outside of the case and replacing the signage can usually be done with no disruption of power. In areas with repeating problems, anti-graffiti paint may be an effective solution.

Rusting of a pad-mounted switchgear enclosure can lead to perforation and a public safety hazard. Touch-up and re-painting may delay the rusting process, but eventually a planned replacement of the equipment will be required.

Accumulation of dirt and pollution can often be removed by cleaning, and on-line cleaning using dry ice is one of the modern technologies used successfully.

Average life of pad-mounted disconnect switches is approximately 40 years. Consequences of switchgear failure include customer interruptions, health and safety as well as environmental consequences.

14.2 Health Index Methodology

14.2.1 Health Index Formulation

The generic Health Index formulation for pad-mounted switchgear is shown below. There was insufficient data to apply the formulas for pad-mounted switchgear. Note that asset age distribution and typical industry-established age-based failure curves a similar to the ones shown in Section 3.3 of this report re used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys.

$$HI = \frac{\sum_{m=1}^{5} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m\,\max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n\,\max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

14 PAD-MOUNTED SWITCHGEAR

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 14-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m,max}$
1	Physical condition	3	4
2	Switch/fuse condition	5	4
3	Cooling	5	4
4	Insulation	7	4
5	Reliability	5	4
Multiplying factor (oil switchgear only)*		Table 14-14	
Expert opinion (switchgear at specific locations) **		Table 14-14	

* Final Health Index result to be multiplied by a factor between 0-1 if applicable
** Expert opinion overrides the calculation result in this case

Table 14-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	Corrosion	Table 14-7	3	4
2	Access	Table 14-8	1	4
3	Base	Table 14-9	2	4
Multiplying factor		Table 14-14	For corrosion only	

Table 14-3 Switch/Fuse Condition (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	Switch/fuse	Table 14-10	5	4
2	Cable connection	Table 14-10	2	4

Table 14-4 Cooling (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	Temperature	Table 14-12	1	4
2	Oil leak	Table 14-10	1	4
Multiplying factor		Table 14-14	For oil leak only	

Table 14-5 Insulation (m=4) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	Bushing	Table 14-10	2	4
2	Flashover	Table 14-10	3	4
Multiplying factor		Table 14-14		

Table 14-6 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	overall	Table 14-11	2	4
2	age	Table 14-13	1	4

14.2.2 Condition Criteria

14.2.2.1 ***Individual Condition Based on Site Inspection***

Table 14-7 Corrosion condition

Condition Description	CPF
None	4
Rust	0
Painting	1

Table 14-8 Access condition

Condition Description	CPF
O.K.	4
Problem	0
Tree	0

Table 14-9 Base condition

Condition Description	CPF
Good	4
Fair	2
Needs Repair	0

Table 14-10 Defect condition (bushing, flashover, leak, cable connection)

Condition Description	CPF
YES	0
NONE	4

Table 14-11 Overall condition

Condition Description	CPF
No Action Required	4
Follow-up Required	3
Correct During Planned Maintenance	1
Immediate Action Required	0

14.2.2.2 Individual Condition Based on Measurement

Table 14-12 Temperature condition

Condition Description (T)	CPF
0	4
25	3
35	2
40	1
40.1	0

14.2.2.3 Individual Condition Based on Intrinsic Characteristics

Age

Table 14-13 Switchgear age (year)

Condition Rating	CPF	Condition Criteria
A	4	0-19
B	3	20-39
C	2	40-59
D	1	60-69
E	0	>= 70

14.2.2.4 Expert Opinion

Table 14-14 Expert opinion

Condition Description	Health Index	Multiplying factor
Air-insulated PMH air (flashover)		0
Air-insulated (corrosion)		0
Air-insulated 27.6 kV (insulation)		0
Federal Pacific (insulation, corrosion)		0
LVS 15-30 years (oil leak, corrosion)		0
Oil switchgear		0.5
Switchgear at Nexus St.	100%	
Switchgear at George St.	0%	
Switchgear at Lockwood Rd.	100%	

14.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for pad mounted switchgear:

- Have problems with LVS 15-30-year old units
- SF6 switchgear are OK in general
- Air-insulated switchgear have corrosion problems, vacuum-insulated switchgear are OK
- Air-insulated air switchgear (PMH type) are experiencing flashovers due to contamination
- Currently replacing old units inherited from Ontario Hydro
- OEB inspection results are available
- Problem with moisture in air-insulated units and inadequate insulation (built to 25kV standards used at 27.6kV). Vacuum-insulated are preferred in this application.

14.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

In total, 18 pad mounted switchgears were looked at during field inspection. The results of the field survey are shown on Table 14-15.

Table 14-15 Pad Mounted Switchgear Survey

Location / Identifier	Main Cabinet Condition	Pad Condition	Insulators Condition	Contact Condition	Operating Mechanism Condition	Electrical Connections Condition	Signs of Over Heating?	Overall Condition
Greenbriar and Central Park (3051-3054)	B	C	C	U	B	B	B	B
1140 Central Park (414-417)	B	B	C	C	B	B	B	B
980 Central Park (3074-3077)	A	A	B	C	B	B	B	B
Glenforest and Grenoble (3055-3058)	B	C	B	U	B	B	B	B
Jordan south of Jefferson (3061-3064)	B	B	B	C	B	B	B	B
Jordan south of Joshua (3315-3318)	B	B	B	B	B	B	B	B
Jordan and North Park (5960-5963)	A	A	A	A	A	A	A	A
North Park west of Torbram (3464-3467)	A	A	A	A	A	A	A	A
North park west of Jordan (5956-5959)	A	A	A	A	A	A	A	A
North Park and Jefferson (5952-5955)	A	A	A	A	A	A	A	A
3111, 3112, 3113, 3114	C	B	D	B	B	B	B	D
3568, 3569, 3570, 3571	C	C	B	C	B	C	C	C
3107, 3108, 3109, 3110	C	B	C	B	B	B	A	C
3087, 3088, 3089, 3090	D	B	C	B	B	C	B	D
3095, 3096, 3097, 3098	A	C	A	A	A	B	A	B
3099, 3100, 3102	C	B	C	B	B	B	B	C
20-288, 20-289, 3906, 3907	A	A	A	A	A	A	A	A
20-320, 20-321, 3968, 3969	C	B	U	U	U	N	A	B
20-254, 20-255, 3795, 3796	C	A	U	U	U	U	A	B

14 PAD-MOUNTED SWITCHGEAR

The site survey ratings are summarized on Table 14-16.

Table 14-16 Summary of Pad Mounted Switchgear Site Survey Ratings

	#A	#B	#C	#D
Main Cabinet Condition	7	5	6	1
Pad Condition	7	8	4	0
Insulators Condition	6	5	5	1
Contact Condition	6	5	4	0
Operating Mechanism Condition	6	11	0	0
Electrical Connections Condition	5	10	2	0
Signs of Over Heating?	9	9	1	0
Overall Condition	5	9	3	2
Sum	51	62	25	4
% of Known	35.9%	43.7%	17.6%	2.8%

The site survey ratings for Overall Condition are summarized on Figure 14-1.

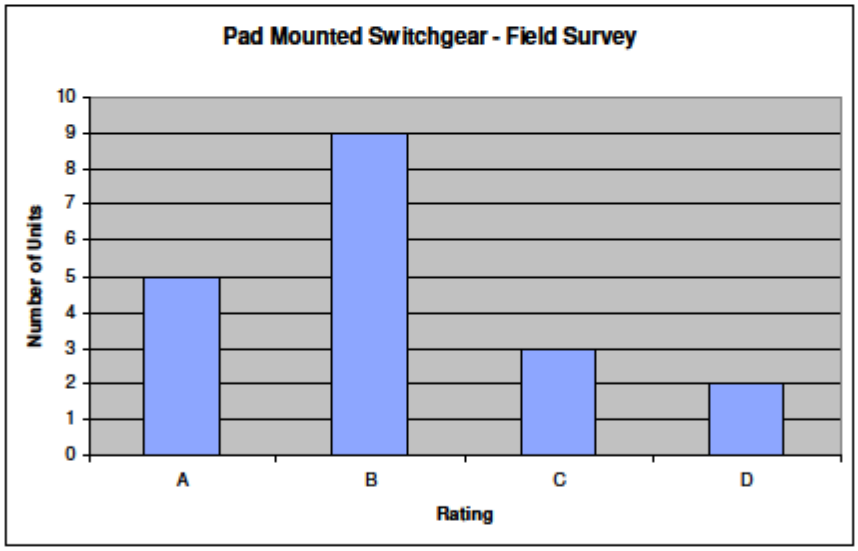


Figure 14-1 Pad Mounted Switchgear - Field Survey Summary for Overall Conditions

14.5 Health Index Distribution

The Health Index distribution is shown on the figure below:

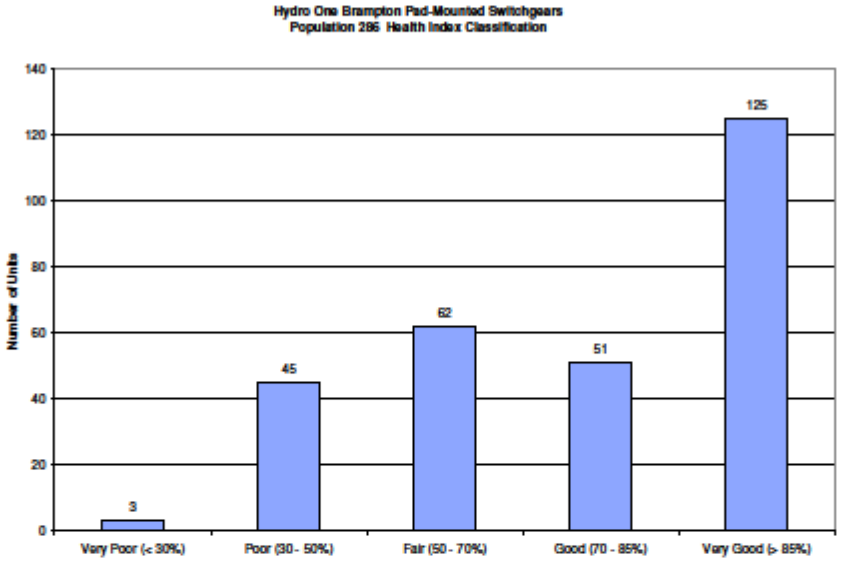


Figure 14-2 Pad Mounted Switchgear Health Index Distribution

14.6 Age Distribution

The age distribution is shown on the figure below:

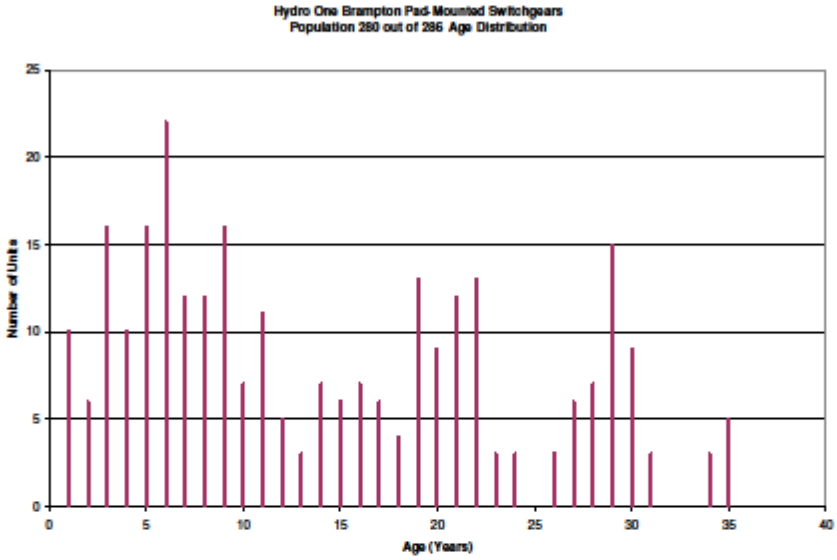


Figure 14-3 Pad Mounted Switchgear Age Distribution

14.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

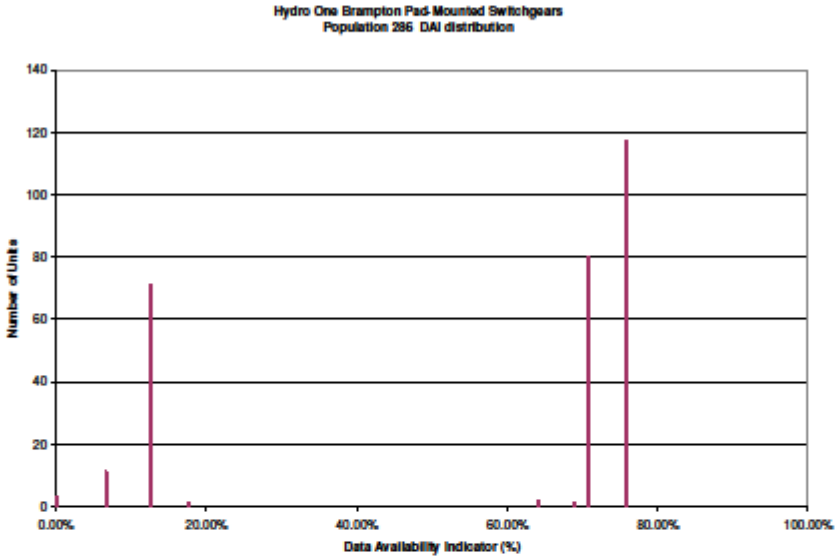


Figure 14-4 Pad Mounted Switchgear Data Availability Indicator Distribution

14.8 Capital Replacement Plan

This asset category is a typical minimal risk cost type. The associated cost of failure is the asset replacement cost. Accordingly a probability of failure replacement plan was developed with $\alpha = 128$ and $\beta = 0.044$. In addition:

- Population of 286 of which 280 or 98% had data. No extrapolation was done as the "known" assets provide almost complete coverage.
- As all the types of this asset had very close replacement costs from HOBNI provided cost data, an average cost of about $50k was used.
- Because the replacements are based on probability of failure for each year, given the age distribution of the asset, no levelizing of the yearly replacement costs is possible.

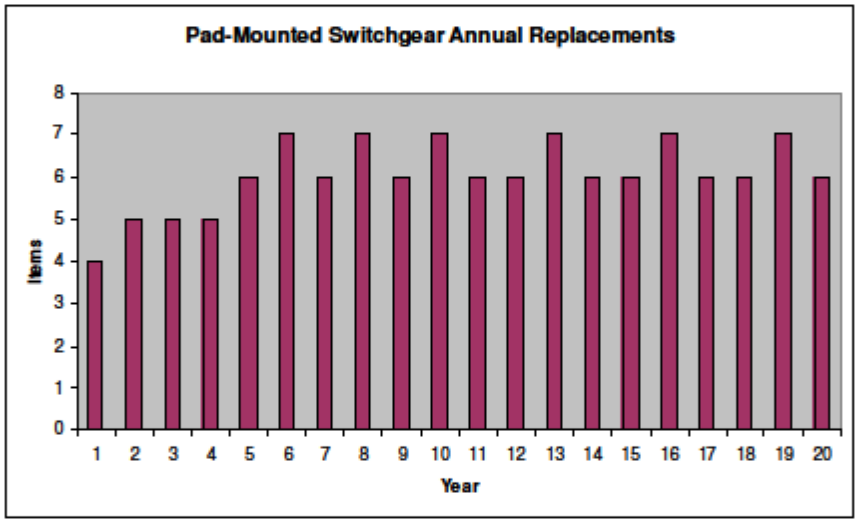


Figure 14-5 Pad Mounted Switchgear Yearly "Probable Failure" Replacements

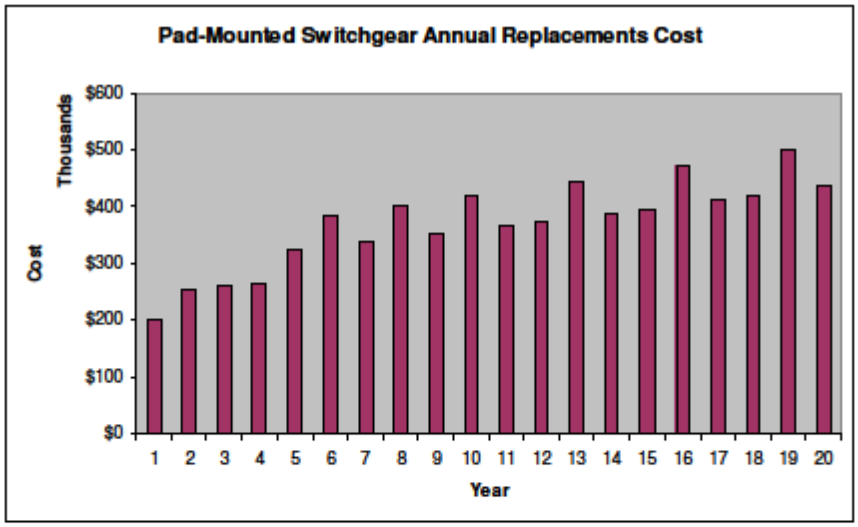


Figure 14-6 Pad Mounted Switchgear Yearly "Probable Failure" Replacement Cost

14.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset, as the CRP approach is *reactive*.

14.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 128$ and $\beta = 0.044$. The median end of life for pad mounted switchgear is 50 years. The maximum end of life is 90 years.

14.11 Data Gap Closure

This section outlines the data gap for pad mounted switchgears, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Inspection results
- Temperature
- Age

Data Gap

Type of Data Gap	Priority
Switch/fuse (CM)	P2

14 PAD-MOUNTED SWITCHGEAR

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15 WOOD POLES

15. WOOD POLES

The support structures for overhead distribution circuits in HOBNI are combination of wood poles and concrete poles. There are currently uses 10314 wood poles in use. At locations with high mechanical loading, such as dead ends, angles and corners, the poles are typically supported by guy wires attached to anchors installed in the ground.

Wood poles are the most common form of support for overhead circuits. Wood species commonly used on distribution systems are predominately Red Pine, Jack Pine and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Douglas Fir, Northern Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

15.1 Degradation Mechanism

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on the electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests, such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers that record and analyze the vibration caused by a hammer blow to identify patterns that indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonic, X-rays, electrical resistance measurement have also been widely used.

15 WOOD POLES

Although wood pole condition assessment is driven by the condition of the wood pole itself, replacement of the ancillary components, foundations, cross-arms, guys, anchors and insulators may also be required. The poles, foundations and cross-arms support the required insulation and phase conductors. The guys and anchors maintain the mechanical integrity of the structure and the insulators electrically insulate the conductor from ground potential.

There are many factors considered by utilities when establishing condition of wood poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The life expectancy of wood poles ranges from 40 to 80 years, with 60 years being the mean. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for a significant number of customers.

15.2 Health Index Methodology

15.2.1 Health Index Formulation

The generic Health Index formulation for wood poles is shown below. There was sufficient data to apply the formulas for wood poles. Note that asset age distribution and typical industry-established age-based failure curves similar to the ones shown in Section 3.3 of this report are used if there is insufficient information to utilize the formulas. In groups where only part of the population has data, distributions are extrapolated to the remaining assets in the group on the basis of age distribution. For example, if 500 assets of a population of 1000 had age data, and 100 of the 500 had ages between 6 and 10 years inclusively, then the extrapolation is made that 200 assets of the total population have ages between 6 and 10 years are of the same type. Also note that calculated and estimated Health Indices can be adjusted based on expert opinion and field surveys

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m,\max} \times WCP_m)}$$

where

$$\mathrm{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n,\max} \times WCPF_n)} \times 4$$

and

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

CPF = Sub-condition Parameter Factor
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)

β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

15 WOOD POLES

Tables depicting condition parameter scores and weights and sub-condition parameter factors and weights are shown below:

Table 15-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m,max}$
1	Mechanical & electrical	5	4
2	Pole physical	3	4
3	Pole accessories	1	4
4	Overall	4	4

Table 15-2 Mechanical & Electrical (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	pole test results	Table 15-8	3	4
2	ground test	Table 15-9	1	4

Table 15-3 Pole Physical (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	rot	CPF =0 for each condition parameter that appears in "pole condition description", otherwise CPF=1	2	4
2	damage		2	4
3	hole		2	4
4	separation		2	4
5	void		1	4
6	ant		1	4
7	lean		1	4

Table 15-4 Pole Accessory (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	tree in wire	CPF =0 for each condition parameter that appears in "pole condition description", otherwise CPF=1	3	4
2	guy wire		3	4
3	ground		2	4
4	riser		1	4

Table 15-5 Overall (m=4) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n,max}$
1	visual	Table 15-6	1	4
2	estimated life	Table 15-7	3	4
3	age	Table 15-10	1	4

15.2.2 Condition Criteria

15.2.2.1 ***Pole Condition Based on Routine Inspection***

Table 15-6 Visual inspection condition

Condition Description	CPF
P (Pass)	4
F (Fail)	0

Table 15-7 Estimated life (effective age) condition

Condition Rating	CPF	Condition Description
A	4	0
B	3	2
C	2	5
D	1	10
E	0	11

15.2.2.2 ***Pole Test Results***

Table 15-8 Pole test results

Condition Description	CPF
To be replaced	0
To be treated	2
To be tested	4

Table 15-9 Ground test results

Condition Rating	CPF	Condition Description
A	4	0
B	3	20
C	2	25
D	1	30
E	0	31

15.2.2.3 ***Pole Age***

Table 15-10 Pole age (year)

Condition Rating	CPF	Condition Description
A	4	0-19
B	3	20-39
C	2	40-59
E	0	>=60

15.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for wood poles:

- New poles are typically concrete. So far no issue is reported on concrete poles.
- Wood poles typically replaced by wood poles on a one-for-one basis
- When replacing poles all the attachments are replaced as well
- A significant number of poles are replaced during road widening
- The last testing done in 2000. Pole test data are available.
- Trouble reports are available
- New wood poles are fully treated
- Rear lot wood pole secondary lines are suspect but few in number
- OEB inspection results are available (photos of poles)
- Western Red Cedar predominates

15.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

The results of the field survey are shown below:

Table 15-11 Wood Pole Survey

Wood Pole Location	1272 Queen St.	2100 Embleton Rd., Huttonville	9108 Heritage Rd.	McLaughlin/Kingnoll	7935 Kennedy Rd.	Marsden & Cornwall	Dean St. West of Kennedy	Centre & McCaul	Bramalea Rd at MS18	Torbram & Williams Pkwy	11623 Dixie Rd.	Kennedy/Sandalwood
Holes and Cracks ?	C	C	C	B	B	B	C	D	B	B	A	B
Rot ?	B	C	D	B	B	C	C	D	B	B	A	B
Cross arm Condition	N	N	D	N	N	C	C	N	N	N	N	N
Overall Pole Condition	D	C	D	B	B	C	C	D	B	B	A	B

The site survey ratings are summarized as follows:

Table 15-12 Summary of Wood Pole Ratings

	#A	#B	#C	#D
Holes and Cracks ?	1	6	4	1
Rot ?	1	6	3	2
Cross arm Condition	0	0	2	1
Overall Pole Condition	1	5	3	3
Sum	3	17	12	7
% of Known	7.7%	43.6%	30.8%	17.9%

15.5 Health Index Distribution

The Health Index distribution is shown below:

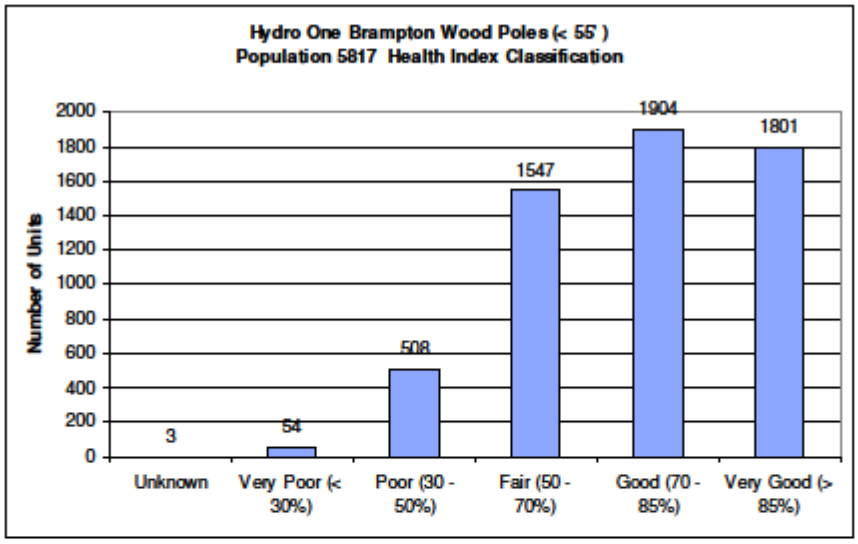


Figure 15-1 Wood Poles < 55ft Health Index Distribution

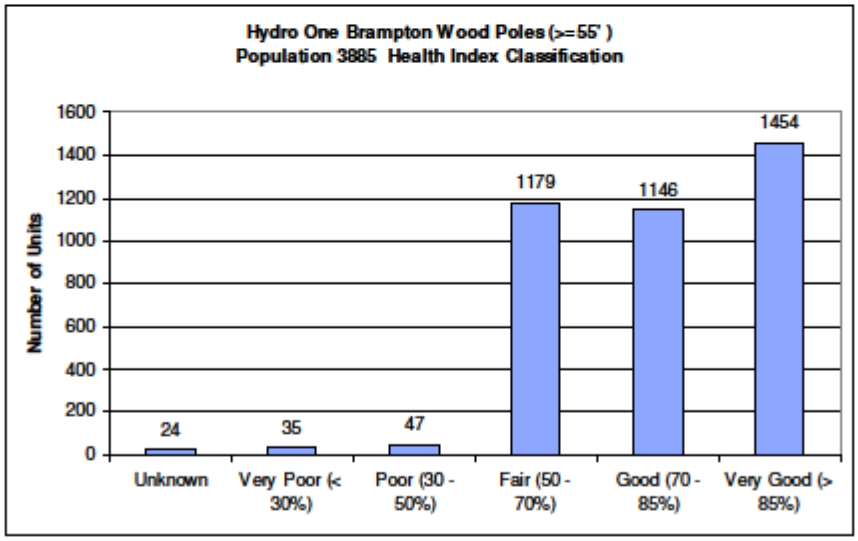


Figure 15-2 Wood Poles ≥ 55ft Health Index Distribution

15.6 Age Distribution

The age distribution for wood poles is shown below:

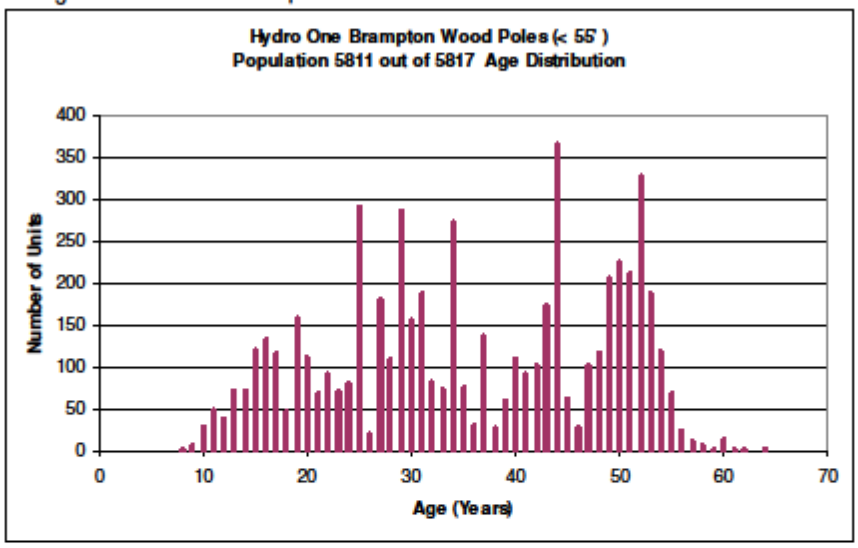


Figure 15-3 Wood Poles < 55ft Age Distribution

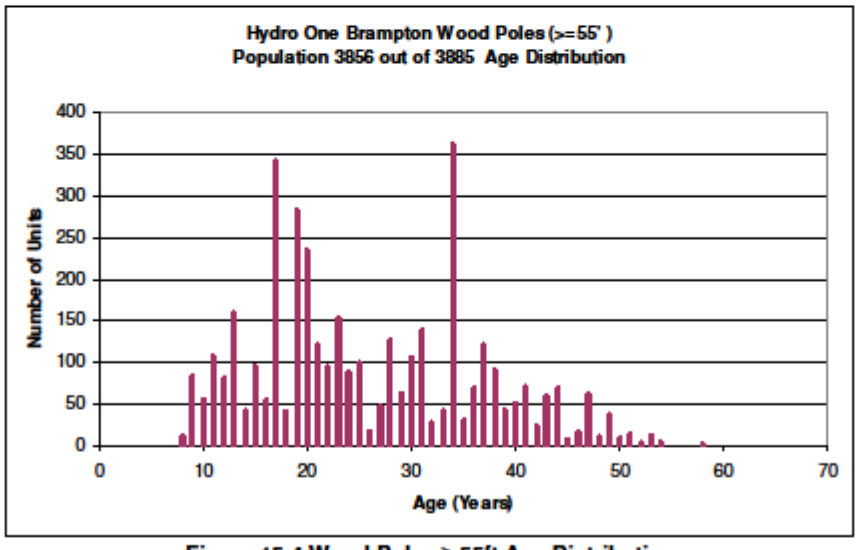


Figure 15-4 Wood Poles ≥ 55ft Age Distribution

15.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown below:

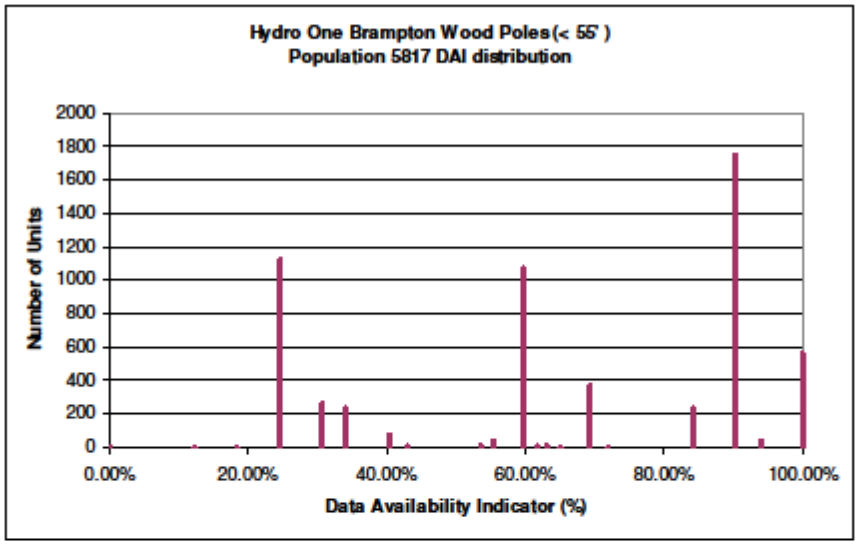


Figure 15-5 Wood Poles < 55ft Data Availability Distribution

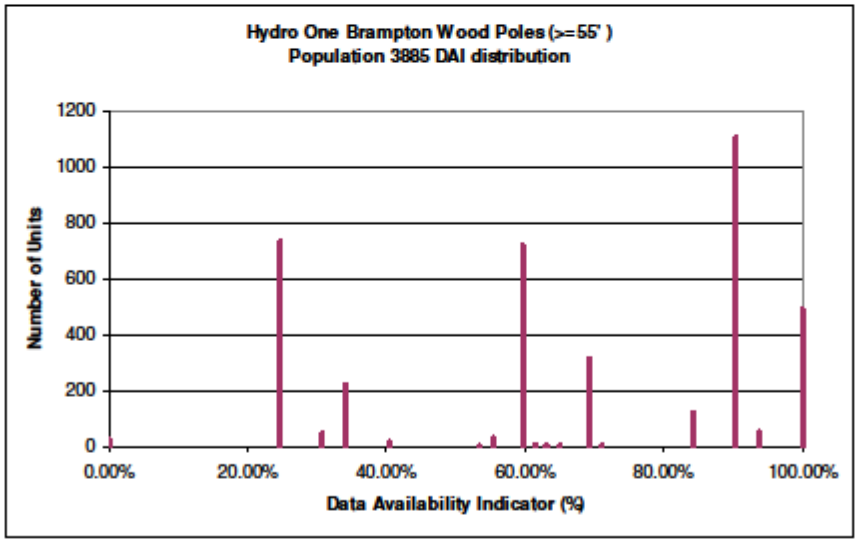


Figure 15-6 Wood Poles ≥ 55ft Data Availability Indicator Distribution

15.8 Capital Replacement Plan

This asset category is a typical minimal risk cost type. The associated cost of failure is the asset replacement cost. Accordingly a probability of failure replacement plan was developed with $\alpha = 98$ and $\beta = 0.071$ based on HOBNI expert opinion on the number of yearly pole replacements. At HOBNI's request these data have been split into two groups: less than 55 feet (16.764 m) and greater than or equal 55 feet. In addition:

- HOBNI provided two sets of pole data: "Matscan" with a listing of 9,702 poles of which 9,667 or 99.6% had age data. The other data set had a listing of 10,617 poles with 4,208 or 39.6% having data. Unfortunately, the two data sets could not be merged due to differences in pole identification. The Matscan data set was used for Health Indexing and replacement plan purposes.
- Asset costs were either looked up directly or interpolated (based on height) from HOBNI provided cost data. The average replacement cost of a pole in this entire data set is $8k.
- Because the replacements are based on probability of failure for each year, given the age distribution of the asset, no levelizing of the yearly replacement costs is possible.
- One cautionary note is that both sets of data are missing any pole data for those that may have been installed in the last 5 years. Probability of failure calculations would predict that some 1% or more of this young population could fail for various reasons. This study does not include these possible replacements nor is the size of this "young" pole population known as of this writing.

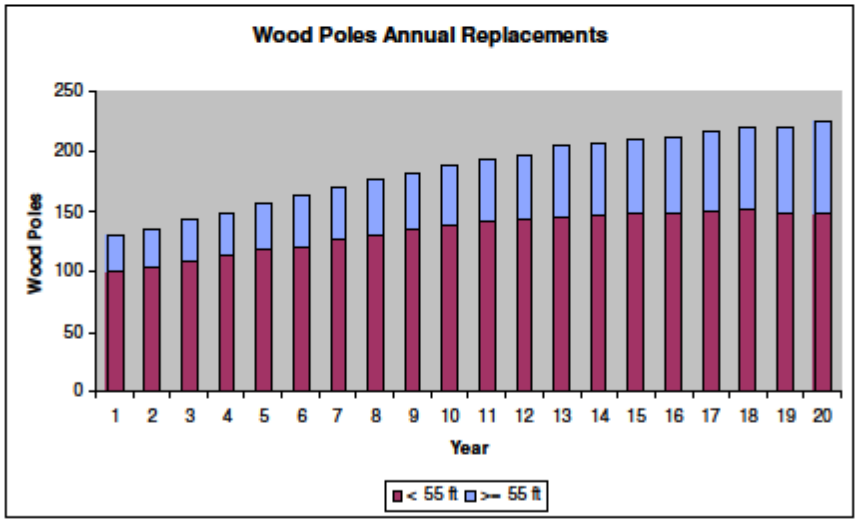


Figure 15-7 Wood Poles Yearly "Probable Failure" Replacements

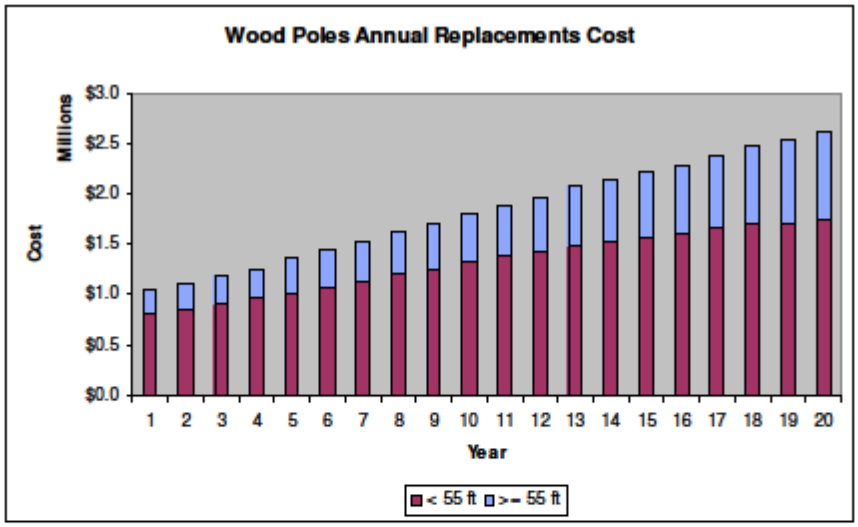


Figure 15-8 Wood Poles Yearly "Probable Failure" Replacements Cost

15.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset, as the CRP approach is *reactive*.

15.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 98$ and $\beta = 0.071$. The median end of life for wood poles is 55 years. The maximum end of life is 80 years.

15.11 Data Gap Closure

This section outlines the data gap for wood poles, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided

- Inspection record
- Age

Data Gap

Type of Data Gap	Priority
Quantitative pole strength (measurement)	P1

16 PRIMARY (FEEDER) XLPE UNDERGROUND CABLE

16. PRIMARY (FEEDER) XLPE UNDERGROUND CABLE

Hydro One Brampton Networks Inc. currently uses 222 three phase circuit-km (665 conductor-km) of Primary (Feeder) Cross-Linked Polyethylene (XLPE) Underground cable.

Distribution system underground feeder cables consist of underground cables, splices/joints, elbows, potheads and terminators at voltage levels 44 kV and below. It includes direct buried and installed-in-duct feeder cables, underground cable sections running from stations to overhead lines and from overhead lines to customer stations and switches.

The use of insulated cables on distribution feeders has virtually become a standard in most North American jurisdictions for urban residential areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental or safety reasons. The initial capital cost of a distribution underground feeder cable circuit is approximately three times the cost of an overhead line of equivalent capacity and voltage.

Distribution underground feeder cables are one of the more challenging assets for electricity systems from a condition assessment and asset management viewpoint. Underground cables are a relatively expensive asset. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Underground cable systems unlike overhead lines, do not suffer from weather induced faults and have better reliability records.

16.1 Degradation Mechanism

Faults on underground feeder cables are usually caused by insulation failure within a localized area and when failures do occur they can be repaired at much lower cost than replacement of the entire cable. Thus, the standard approach to cable system management has been based on reliability rather than the balance between repair and replacement costs. As long as the reliability is within acceptable levels, it is virtually always cheaper to repair than replace cables.

Many utilities with high proportions of relatively old underground cables have concerns about reliability. Condition assessment programs enable utilities to prioritize the cable replacement programs based on available budgets.

Over the past 30 years XLPE insulated cables, due to their lower costs and easier splicing have all but replaced paper-insulated cables in new installations. The existing population of XLPE cables is still relatively young in terms of normal cable lifetimes. Therefore, failures that have occurred can be classified as early life failures. In the early days of polymeric insulated cables, their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced during manufacturing. Over the past 30 years many of these problems have been addressed, and modern XLPE cables and accessories are generally considered very reliable if manufactured and installed through competent workmanship.

16 PRIMARY (FEEDER) XLPE UNDERGROUND CABLE

Polymeric insulation is very sensitive to discharge activity, thus, cable, joints and accessories must be discharge free when installed. Water penetration into the insulation/conductor barrier, existence of impurities within the semicon layer and presence of high dielectric stress are the principal causes of insulation treeing and the most significant degradation processes for earlier generation of polymeric cables. The rate of water tree growth depends on the quality of the polymeric insulation and the manufacturing process. In addition to manufacturing improvements, development of tree retardant XLPE cables and designs with metal foil barriers and water migration controls have further reduced the rate of deterioration from treeing.

Examining recovered failed cable samples to detect and quantify treeing serves as an effective means to assess the general condition and estimate the future life of XLPE cables. Alternatively, accelerated electrical testing of recovered cables can also be used to determine condition.

Most utilities are beginning to determine the condition of their cables through lab testing and in-situ testing. In the absence of testing, the only other indicators of cable health are:

- Number of failures per unit length of installation
- Age of Cables

At this time, the precise life expectancy of XLPE cables is difficult to ascertain. There is concern that these cables will have a shorter lifetime than the earlier paper insulated cables, but experience is still limited. The life expectancy of tree-resistant (TR) XLPE cables is considered in excess of 40 years.

The major consequences of cable failure are adverse impacts on reliability. Fundamentally, end of life cannot be predicted since most insulation system failures are related to the occurrence of a transient event such as an overvoltage caused by breaker operations, lightning strikes or flashovers, etc. However, via diagnostic testing, the condition of the insulation can be assessed to the point where an occurrence of a transient event will likely result in a failure.

16.2 Health Index Methodology

16.2.1 Health Index Formulation

In this study, the Health Index formulation for XLPE primary cables is based on age only, due to lack of other condition parameter data.

Health Index = age_score*multiplying_factor/4

Where

Table 16-1 Age condition

age_score	Condition criteria (age, year)
4	>1<10
3	>1<15
2	>15<25
1	>25<30
0	>30

And

Table 16-2 Multiplying factor

Multiplying_factor	Condition criteria (failures/100 km/year)
1	0
0.9	15
0.8	25
0.7	35
0.6	51

16.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for Primary XLPE U/G cables:

- Majority (75%) direct buried
- Cable faults are the biggest concern affecting system reliability
- Usually rebuild after 3 faults occur within a twelve month period
- The aging conductors were typically installed in the 1970's
- The major issue is cable insulation breakdown in primary system
- In densely populated areas refurbish using BIL restoration injection rather than replace: prohibitively expensive replacement costs
- All new designs use in duct

16.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

In total, 19 locations were looked at during the visual inspection. The results of the field survey are shown on Table 16-3.

Table 16-3 Primary (Feeder) XLPE U/G Cables Survey

At Switchgear Location / Identifier	Cable Condition	Termination Condition	Neutral Condition	Overall Cable Condition
Greenbriar and Central Park (3051-3054)	B	C	B	B
1140 Central Park (414-417)	B	C	B	B
980 Central Park (3074-3077)	B	C	B	B
Glenforest and Grenoble (3055-3058)	B	B	B	B
Jordan south of Jefferson (3061-3064)	B	B	C	C
Jordan south of Joshua (3315-3318)	B	B	B	B
Jordan and North Park (5960-5963)	A	A	A	A
North Park west of Torbram (3464-3467)	A	A	A	A
North park west of Jordan (5956-5959)	A	A	A	A
North Park and Jefferson (5952-5955)	A	A	A	A
3111, 3112, 3113, 3114	U	B	C	C
3568, 3569, 3570, 3571	B	C	B	B
3107, 3108, 3109, 3110	B	C	B	B
3087, 3088, 3089, 3090	C	C	C	C
3095, 3096, 3097, 3098	B	B	B	B
3099, 3100, 3102	B	C	B	B
20-288, 20-289, 3906, 3907	B	A	B	B
20-320, 20-321, 3968, 3969	B	C	B	C
20-254, 20-255, 3795, 3796	B	B	B	B

The site survey ratings are summarized on Table 16-4.

Table 16-4 Summary of Primary (Feeder) XLPE U/G Cable Site Survey Ratings

	#A	#B	#C	#D
Cable Condition	4	13	1	0
Termination Condition	5	6	8	0
Neutral Condition	4	12	3	0
Overall Cable Condition	4	11	4	0
Sum	17	42	16	0
% of Known	22.7%	56.0%	21.3%	0.0%

16.5 Health Index Distribution

The Health Index distribution is shown on the figure below (the total value is the sample size):

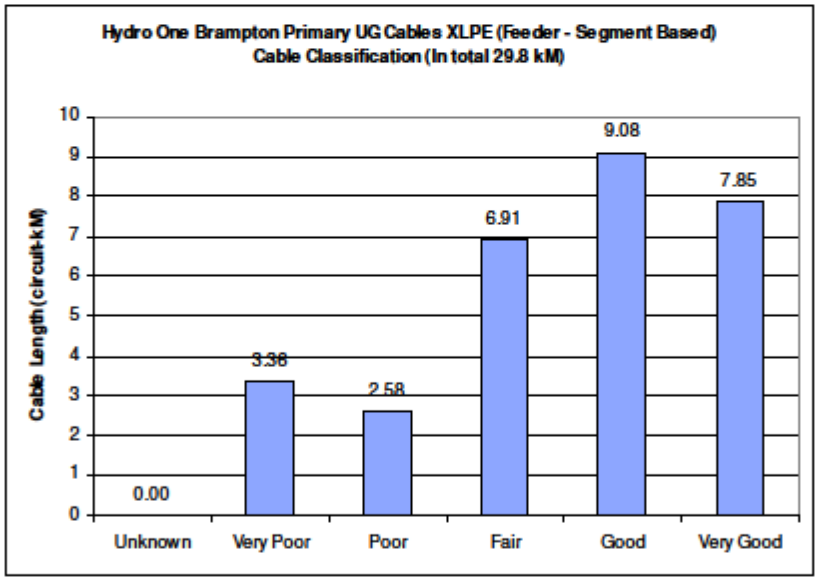


Figure 16-1 Primary (Feeder) XLPE U/G Cable Health Index vs. km Distribution

16.6 Age Distribution

Due to a lack of individual segment age data the age distribution cannot be shown.

16.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

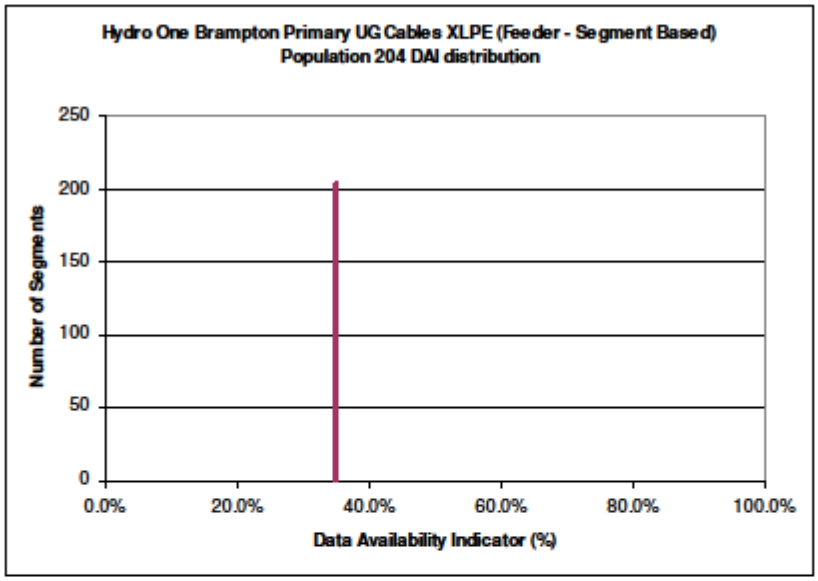


Figure 16-2 Primary (Feeder) XLPE U/G Cable Segments Data Availability Indicator Distribution

16.8 Optimal Capital Replacement Plan

Underground cable is a prime example of a "distributed" asset; that is, its Health Index and replacement plan are quoted on a per unit length basis. Assumptions and details include:

- Total length of (predominantly 3 phase cable): 222 cct-km of which 30 cct-km (13%) was known.
- Average estimated 3 phase replacement cost/metre: $350. The actual replacement cost for segments varies due to the voltage and current ratings.
- Many segments had estimated ages: e.g. ">1<15", ">30". This means the replacement plan will also be an estimate and no age distribution chart was included.
- The risk assessment and capital plan analysis was developed on a per segment basis with probability of failure parameters $\alpha = 48$ and $\beta = 0.112$.
- The unlevelized, "optimal replacement" capital plan peaks at just over $15M in the first year. The levelized plan brings the spending down to about $3.1M over the next 4 years.

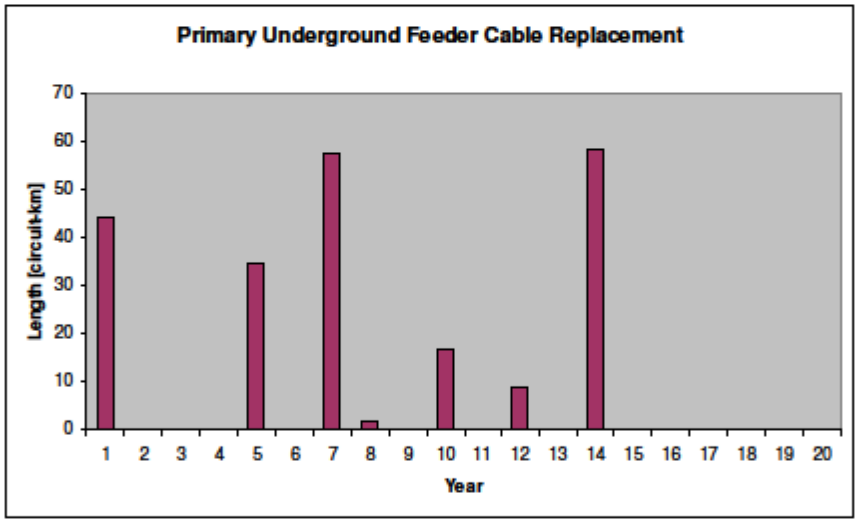


Figure 16-3 Primary (Feeder) XLPE U/G Cable Optimal Yearly Replacement (circuit-km)

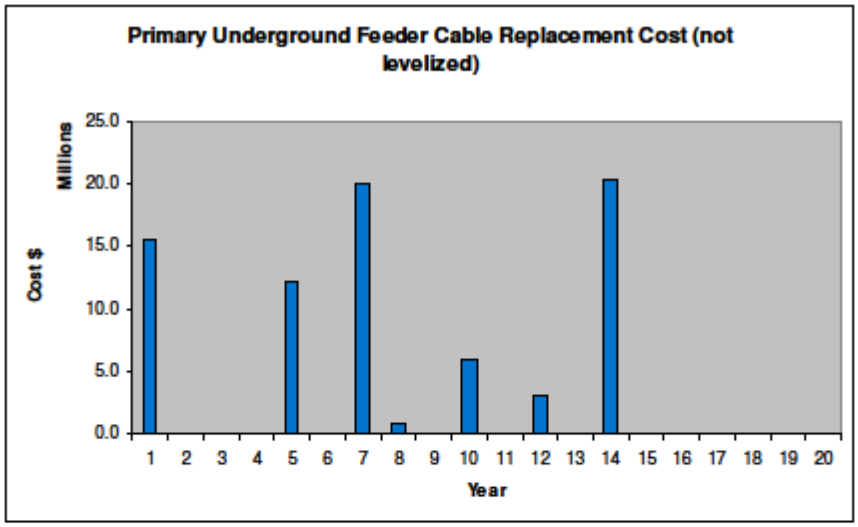


Figure 16-4 Primary (Feeder) XLPE U/G Cable Optimal Yearly Replacement Cost

16.9 Levelized Capital Replacement Plan

Some of the *proactive* replacements of Primary (Feeder) XLPE U/G Cables can be spread out over several years without significantly increasing the risk of failure thus resulting in more evenly spread annual expenditures. This is referred to as a "Levelized Capital Replacement Plan" and it is presented in Figure 16-6.

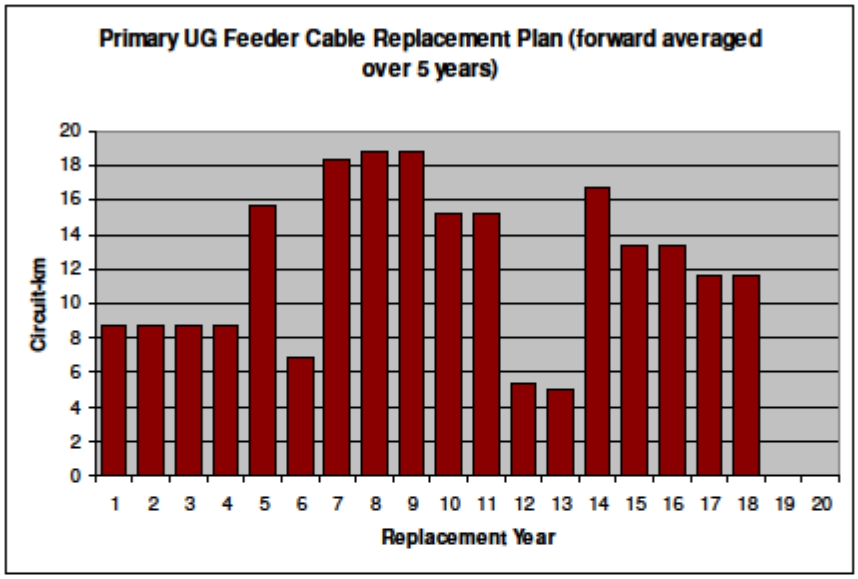


Figure 16-5 Levelized Replacement Plan for Primary (Feeder) XLPE U/G Cable (circuit-km)

16 PRIMARY (FEEDER) XLPE UNDERGROUND CABLE

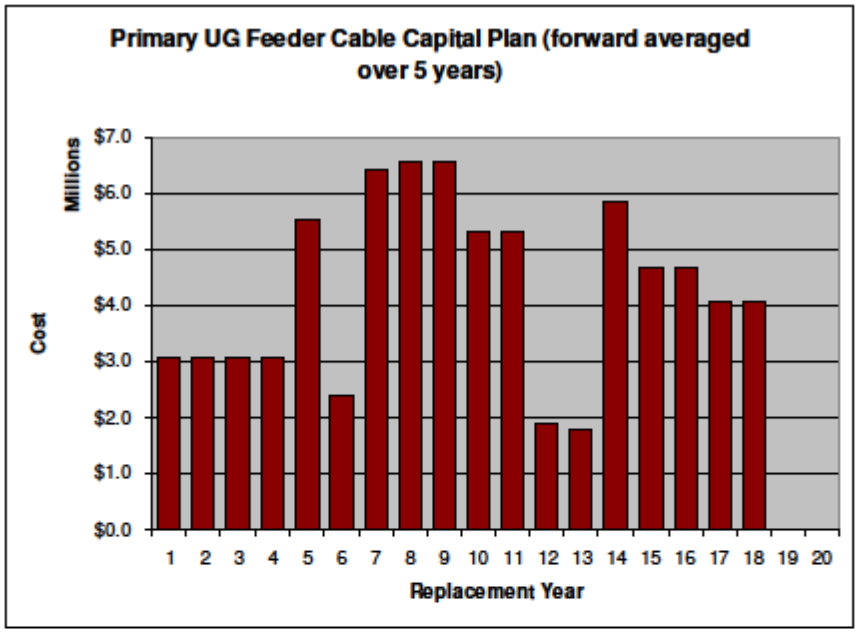


Figure 16-6 Levelized Capital Replacement Plan for Primary (Feeder) XLPE U/G Cable (circuit-km)

16.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 48$ and $\beta = 0.112$. The median end of life for the Primary XLPE U/G cable is 25 years. The maximum predicted end of life is 40 years.

16.11 Data Gap Closure

This section outlines the data gap for primary XLPE U/G cables, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Failure record
- Segment length
- Age

Data Gap

Type of Data Gap	Priority
IR scan (measurement)	P1
Loading (measurement)	P2
Cable splice (CM)	P2
Gasket joint (CM)	P2
Other CM or measurement	P3

17 PRIMARY (DISTRIBUTION) XLPE UNDERGROUND CABLE

17. PRIMARY (DISTRIBUTION) XLPE UNDERGROUND CABLE

Hydro One Brampton Networks Inc. currently uses 2,246 conductor-km of Primary (Distribution) (1,721 circuit-km) Cross-Linked Polyethylene (XLPE) Underground cable.

Distribution system underground cables consist of underground cables, splices/joints, elbows, potheads and terminators at voltage levels 27.6 kV and below. It includes direct buried and installed-in-duct cables, underground cable sections running from overhead lines to customer service connections and switches. These cables are usually used to bring supply to subdivisions and the voltage to individual residences is then stepped down using pad mounted transformers.

The use of insulated cables on distribution feeders has virtually become a standard in most North American jurisdictions for urban residential areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental or safety reasons. The initial capital cost of a distribution underground cable circuit is approximately three times the cost of an overhead line of equivalent capacity and voltage.

Distribution underground cables are one of the more challenging assets for electricity systems from a condition assessment and asset management viewpoint. Underground cables are a relatively expensive asset. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Underground cable systems unlike overhead lines, do not suffer from weather induced faults and have better reliability records.

17.1 Degradation Mechanism

Faults on underground cables are usually caused by insulation failure within a localized area and when failures do occur they can be repaired at much lower cost than replacement of the entire cable. Thus, the standard approach to cable system management has been based on reliability rather than the balance between repair and replacement costs. As long as the reliability is within acceptable levels, it is virtually always cheaper to repair than replace cables.

Many utilities with high proportions of relatively old underground cables have concerns about reliability. Condition assessment programs enable utilities to prioritize the cable replacement programs based on available budgets.

Over the past 30 years XLPE insulated cables, due to their lower costs and easier splicing have all but replaced paper-insulated cables in new installations. The existing population of XLPE cables is still relatively young in terms of normal cable lifetimes. Therefore, failures that have occurred can be classified as early life failures. In the early days of polymeric insulated cables, their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced during manufacturing. Over the past 30 years many of these problems have been addressed, and modern XLPE cables and accessories are generally considered very reliable if manufactured and installed through competent workmanship.

17 PRIMARY (DISTRIBUTION) XLPE UNDERGROUND CABLE

Polymeric insulation is very sensitive to discharge activity, thus, cable, joints and accessories must be discharge free when installed. Water penetration into the insulation/conductor barrier, existence of impurities within the semicon layer and presence of high dielectric stress are the principal causes of insulation treeing and the most significant degradation processes for earlier generation of polymeric cables. The rate of water tree growth depends on the quality of the polymeric insulation and the manufacturing process. In addition to manufacturing improvements, development of tree retardant XLPE cables and designs with metal foil barriers and water migration controls have further reduced the rate of deterioration from treeing.

Examining recovered failed cable samples to detect and quantify treeing serves as an effective means to assess the general condition and estimate the future life of XLPE cables. Alternatively, accelerated electrical testing of recovered cables can also be used to determine condition.

Most utilities are beginning to determine the condition of their cables through lab testing and in-situ testing. In the absence of testing, the only other indicators of cable heath are:

- Number of failures per unit length of installation
- Age of Cables

At this time, the precise life expectancy of XLPE cables is difficult to ascertain. There is concern that these cables will have a shorter lifetime than the earlier paper insulated cables, but experience is still limited. The life expectancy of tree-resistant (TR) XLPE cables is considered in excess of 40 years.

The major consequences of cable failure are adverse impacts on reliability. Fundamentally, end of life cannot be predicted since most insulation system failures are related to the occurrence of a transient event such as an overvoltage caused by breaker operations, lightning strikes or flashovers, etc. However, via diagnostic testing, the condition of the insulation can be assessed to the point where an occurrence of a transient event will likely result in a failure.

17.2 Health Index Methodology

17.2.1 Health Index Formulation

In this study, the Health Index formulation for XLPE primary cables is based on age only, due to lack of other condition parameter data.

Health Index = age_score*multiplying_factor/4

Where

Table 17-1 Age condition

age_score	Condition criteria (age, year)
4	<1
4	>1<10
3	>1<15
2	>15<25
1	>25<30
0	>30

And

Table 17-2 Multiplying factor

Multiplying_factor	Condition criteria (failures/100 km/year)
1	0
0.9	15
0.8	25
0.7	35
0.6	51

17.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for Primary XLPE U/G cables:

- Majority (75%) direct buried
- Cable faults are the biggest concern affecting system reliability
- Usually rebuild after 3 faults occur within a twelve month period
- The aging conductors were typically installed in the 1970's
- The major issue is cable insulation breakdown in primary system
- All new designs use in duct

17.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

In total, 97 locations were looked at during the visual inspection. The results of the field survey are shown on Table 17-3.

17 PRIMARY (DISTRIBUTION) XLPE UNDERGROUND CABLE

Table 17-3 Primary (Distribution) XLPE U/G Cables Survey

At Pad Mounted Transformer Location / Identifier	Cable Condition	Termination Condition	Neutral Condition	Overall Cable Condition
[illegible]	A	A	A	A
1885 Torbram (3037)	B	B	E	B
69 Glen Forest (7703)	U	U	C	C
1775 Queen E (3002)	B	B	E	B
15 Bas. Bourne Drive (7288)	U	U	L	U
37 East Locure Dr (7102)	A	A	F	A
703 Bramalea (7078)	A	A	A	A
201 [illegible]	A	A	F	A
106 Post Drive (13111)	B	B	E	B
50 Freckle Crt (11007)	A	A	A	A
7 Victor (7688)	B	B	E	B
12810	U	A	L	U
1 [illegible]	B	C	E	B
12138	U	U	A	U
1[illegible]	A	A	F	A
11707	U	U	L	U
12514	A	A	F	A
13706	B	C	E	C
13638	U	U	L	U
740	B	C	E	B
11151	U	C	L	C
12002	A	C	F	C
314	D	D	D	D
11140	A	A	F	A
13750	B	B	E	B
364	U	C	L	U
4588	B	C	E	C
3418	U	U	L	U
2707	A	A	F	A
7651	U	U	L	U
4141	A	C	F	C
[illegible] (13131)	E	E	B	E
[illegible] (13132)	F	F	A	F
[illegible] (13133)	E	E	B	E
[illegible] (13134)	L	L	J	L
Loyola Lane (663)	E	E	B	E
Lecre Lane (663)	L	L	J	L
Lecre Lane (663)	F	F	A	F
Stanley Corberry (3804)	E	E	B	E
Stanley Corberry (3812)	F	F	A	F
Stanley Corberry (3818)	E	E	B	E
Stanley Corberry (3813)	L	L	J	L
Dolly Rise (3815)	E	E	B	E
7 Professors Lake Parkway (2687)	L	L	J	L
47 Glenora Cres (3210)	F	F	A	F
27 Globe (5919)	L	L	J	L
40 Gressmere (1241)	F	F	A	F
13 Howardtor (5385)	E	E	B	E
3 Hereudale (3937)	C	C	C	C

At Pad Mounted Transformer Location / Identifier	Cable Condition	Termination Condition	Neutral Condition	Overall Cable Condition
21 Coldbeck Crescent (3738)	A	F	A	A
9 Huntsberry Square (3741)	B	E	B	B
16 Huntsberry Square (3741)	J	L	U	J
54 Welcome (7948)	B	E	B	B
58 Welcome (7942)	J	L	U	J
33 Welcome (7941)	A	F	A	A
55 Innisfarr (7952)	J	L	U	J
53 Montjoy (7929)	A	F	A	A
43 Montjoy (7936)	B	E	B	B
22 Montjoy (7927)	H	H	H	H
13 Winfield (7938)	B	E	B	B
29 Winfield (7939)	J	L	U	J
41 Winfield (7931)	B	E	B	B
59 Winfield (7931)	J	L	U	J
33 Tomtec Oak (8024)	A	F	A	A
25 Tomtec Oak (8022)	B	E	B	B
34 Homewood (8010)	I	I	II	I
43 Homewood (8010)	B	E	B	B
12 Buckland (8878)	J	L	U	J
41 Buckland (8876)	B	E	B	B
175 Wexbridge trail (9375)	J	L	C	C
190 Weybridge trail (9364)	A	F	A	A
330	C	C	D	D
334	F	C	A	A
337	E	C	B	B
340	C	I	II	II
4727	E	C	B	B
5153	L	C	U	J
5154	F	C	A	C
5123	L	C	U	C
4724	F	C	A	C
4728	E	C	B	B
10784	F	A	A	A
10355	E	A	A	A
10353	L	A	A	J
4537	E	C	B	B
4533	L	C	C	C
4481	F	F	A	A
4480	E	C	C	C
4471	F	C	A	A
1137	E	E	B	B
1350	L	L	U	J
1287	E	C	B	C
1255	C	C	C	C
10155	F	F	C	C
10170	L	C	U	J
170	F	C	A	C
180	E	E	B	B

The site survey ratings are summarized on Table 17-4.

Table 17-4 Summary of Primary (Distribution) XLPE U/G Cables Survey Ratings

	#A	#B	#C	#D
Cable Condition	3	89	2	0
Termination Condition	7	62	24	1
Neutral Condition	7	81	6	0
Overall Cable Condition	5	71	17	1
Sum	22	303	49	2
% of Known	5.9%	80.6%	13.0%	0.5%

17.5 Health Index Distribution

The Health Index distribution is shown on the figure below (total is sample data size):

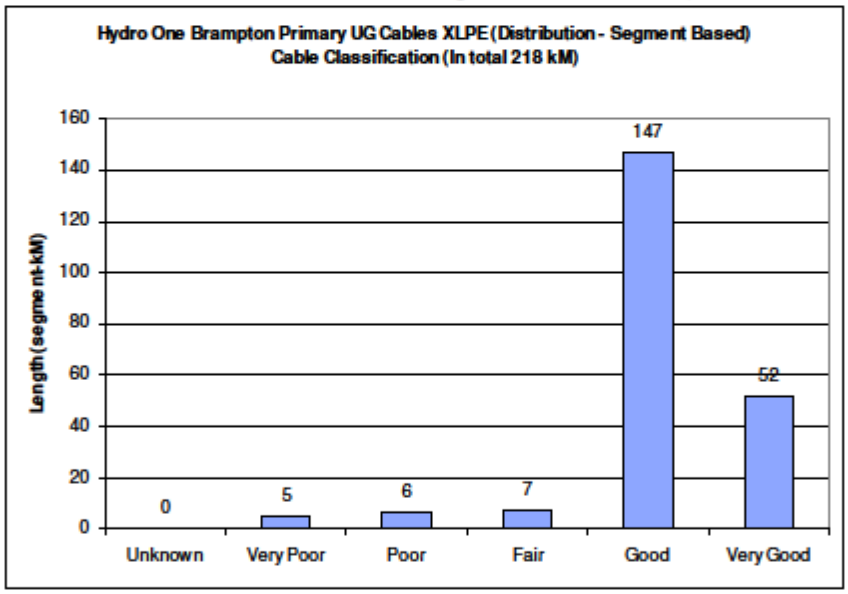


Figure 17-1 Primary (Distribution) XLPE U/G Cable Health Index circuit-km Distribution

17.6 Age Distribution

The age distribution is not shown because of a lack of individual segment age data.

17.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on the following figure:

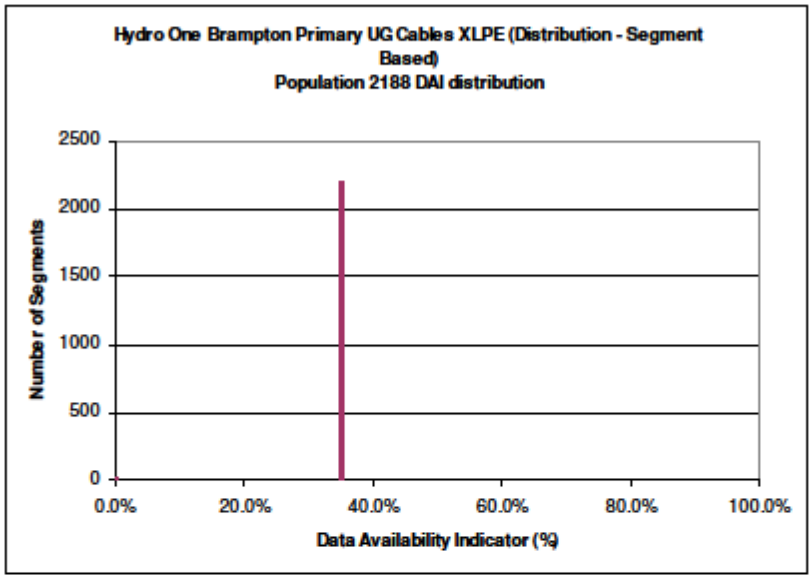


Figure 17-2 Primary (Distribution) XLPE U/G Cable Data Availability Indicator Segment Distribution

17.8 Optimal Capital Replacement Plan

Underground cable is a prime example of a "distributed" asset; that is, its Health Index and replacement plan are quoted on a per unit length basis. Assumptions and details include:

- Total length of "known" conductor about 289 conductor-km of 2,246 conductor-km (13%). (The Health Index is quoted on a length of segment basis where some segments are single phase and others are three phase.)
- Average estimated single phase conductor replacement cost/metre: $75. The actual replacement cost for segments varies due to the voltage and current ratings.
- Many segments had estimated ages: e.g. ">1<15", ">30". This means the replacement plan will also be an estimate and no age distribution chart was included.
- The risk assessment and capital plan analysis was developed on a per segment basis with probability of failure parameters $\alpha = 48$ and $\beta = 0.112$.
- The unlevelized, extrapolated, "optimal replacement" capital plan peaks at over $15M in the first year. HOBNI estimated that the sample segments are, in general, older than the rest of the population. Accordingly the extrapolated amount of cable to be replaced has been scaled back. The corrected, levelized plan brings the spending down to $1.5M over the next 4 years.

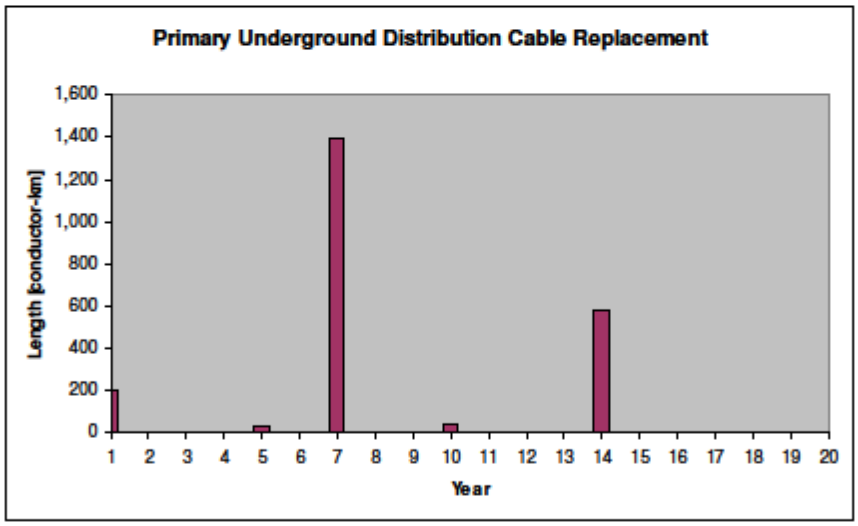


Figure 17-3 Primary (Distribution) XLPE U/G Cable Optimal Yearly Replacement km

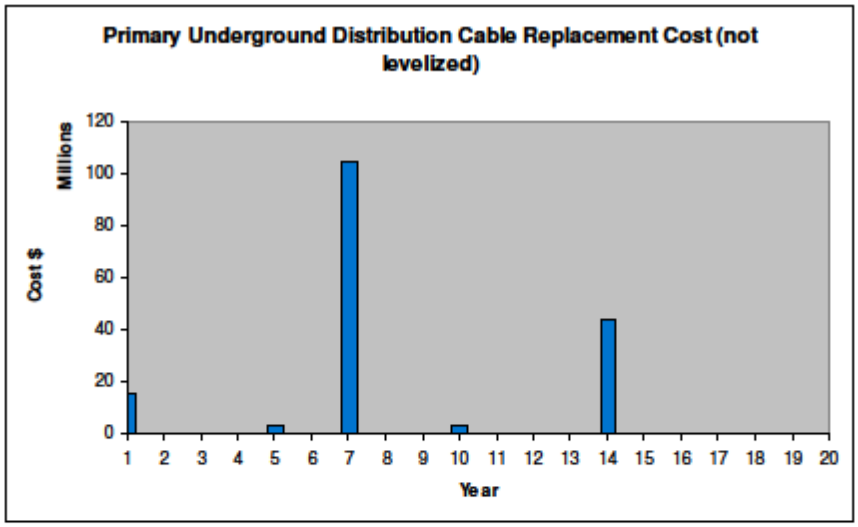


Figure 17-4 Primary (Distribution) XLPE U/G Cable Optimal Yearly Replacement Cost

17.9 Levelized Capital Replacement Plan

Some of the *proactive* replacements of Primary (Distribution) XLPE U/G Cables can be spread out over several years without significantly increasing the risk of failure thus resulting in more evenly spread annual expenditures. This is referred to as a "Levelized Capital Replacement Plan" in Figure 17-6.

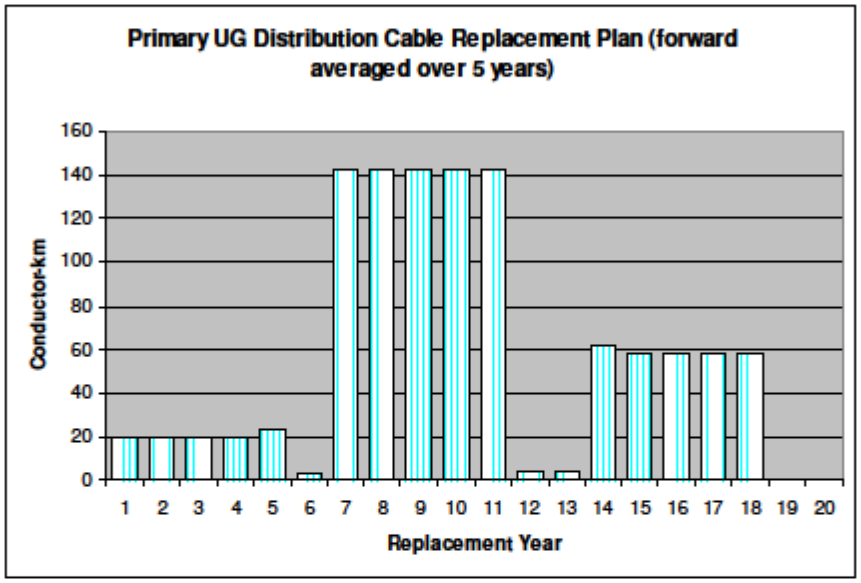


Figure 17-5 Levelized Replacement Plan for Primary (Distribution) XLPE U/G Cable

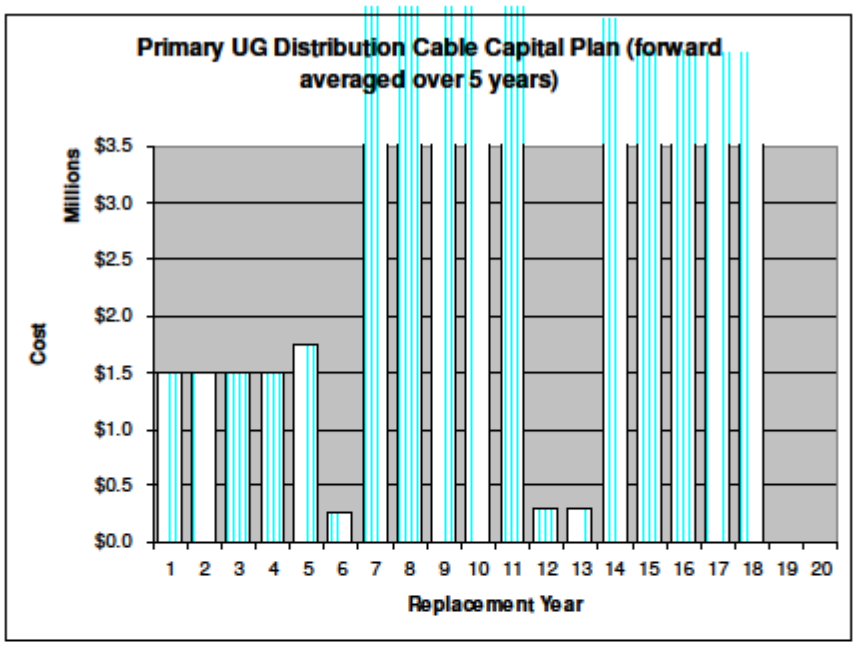


Figure 17-6 Levelized Capital Replacement Plan for Primary (Distribution) XLPE U/G Cable

17.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 48$ and $\beta = 0.112$. The median end of life for the Primary XLPE U/G cable is 25 years. The maximum end of life is 40 years.

17.11 Data Gap Closure

This section outlines the data gap for primary XLPE U/G cables, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

The following data are provided; however, only a little more than 10% of the segments have been sampled to date:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Failure record
- Segment length
- Age

Data Gap

Type of Data Gap	Priority
IR scan (measurement)	P1
Loading (measurement)	P2
Cable splice (CM)	P2
Gasket joint (CM)	P2
Other CM or measurement	P3

17 PRIMARY (DISTRIBUTION) XLPE UNDERGROUND CABLE

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18 BATTERIES

18. BATTERIES

Station battery systems (including battery and charger) are critical to the safe and efficient operation of transformer cooling, switchgear and protection & control. Maintaining batteries in a condition capable of delivering the necessary energy as required is essential.

Effective battery life tends to be much shorter than many of the major components in a station. For traditional wet batteries most electric utilities report a typical lifetime of 15 - 20 years and for the more modern sealed batteries, lifetimes are half of this.

Hydro One Brampton Networks Inc. currently uses 151 SCADA and station batteries.

18.1 Degradation Mechanism

The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.
It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.

Despite the regular and frequent maintenance and inspection of battery systems, failures in service are still relatively frequent. For this reason, many utilities employ battery monitors and alarm systems. The earlier versions of these are still widely used and are relatively unsophisticated devices that measure basic battery parameters with pre-set alarm levels. More modern monitoring devices have the ability to identify a potential failure as it develops and to provide a warning.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Because batteries have relatively short lifetimes (<20 years), there is the need for continuous replacement. In most cases, new batteries are readily available. Utilizing information available from regular maintenance and inspection programs and responding to battery alarms should result in a high overall reliability for batteries. The ability to detect significant deterioration and pre-empt battery failure is especially critical if monitoring and alarm systems are not installed.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree

of reliability and a significantly longer lifetime than the batteries themselves. Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

Typically, maintenance and inspection procedures involve a combination of (1) visual inspections for signs of leaks, internal degradation or evidence of deterioration/damage to connections and external components; and (2) measurement of electrical characteristics and performance of individual cells. Individual inspection and tests on sample cells are carried out on a 3 or 6-month basis (depending on battery type) and a full set of tests are carried out on an annual basis. A battery load test may also be carried out periodically.

For each inspection and test a condition rating or test-pass (TP)/test-fail (TF) criteria can be defined to ensure consistent reporting of results and to enable appropriate remedial steps to be applied.

Historically, battery end-of-life was determined mainly by a number of factors including age, appearance (indication of physical deterioration) and the history of specific gravity and cell voltage measurements. Presently, the battery load test is now considered the "best" indicator of battery condition. This test is now used to identify and confirm the condition of suspect batteries identified from the previous tests.

For battery chargers, diagnostic testing programs are coordinated with the battery maintenance program. This involves a number of functional tests and each test has a defined TP/TF criteria. Failure of any functional test may lead to further investigations or consideration of replacement.

Typically, inspection and testing are carried out on a tri-monthly basis with the full range of tests carried out on an annual basis. These tests involve physical examination for obvious signs of deterioration or damage and measurement of cell characteristics.

In some utilities, battery monitoring systems have been utilized for a many years now. These monitors measure basic characteristics of individual cells and send an alarm if minimum acceptable tolerances or characteristics are not maintained. More sophisticated battery monitoring devices are now available that continuously monitor the characteristics and performance of batteries and battery chargers to provide early indication of significant deterioration prior to the battery failure.

Due to the critical functionality of batteries and battery chargers, most utilities take a conservative approach towards battery replacement: any significant evidence of battery deterioration usually leads to decisions to replace the battery.

18.2 Health Index Methodology

18.2.1 Health Index Formulation

In this study, the Health Index formulation for remote SCADA batteries is based on age only, due to lack of other condition parameter data.

Health Index = age_score / 4

Where

Table 18-1 Age condition

age_score	Condition criteria (age, year)
4	0-5
3	6-10
2	11-15
1	16-20
0	>=20

18.3 Expert Opinion

As per Kinectrics' interviews with HOBNI on-site staff, the following issues and remarks were taken into account for deriving the Health Index for batteries:

- Controls about 100-150 remotely operable switches as well as providing full control of all MS and TS switches
- Also incorporate voltage based auto-transfer schemes
- Only remote SCADA batteries need to be assessed based on their age (RTUs, switches and communication equipment are dealt with as defect management rather than long-term degradation)
- For battery/charger, manufacturer failure rate curve is available
- The health status of battery/charger is mainly age-driven

18.4 Field Surveys

HOBNI staff performed a field survey during the course of this contract which formed the basis of the ACA for this section.

18.5 Health Index Distribution

The Health Index distribution is shown on Figure 18-1.

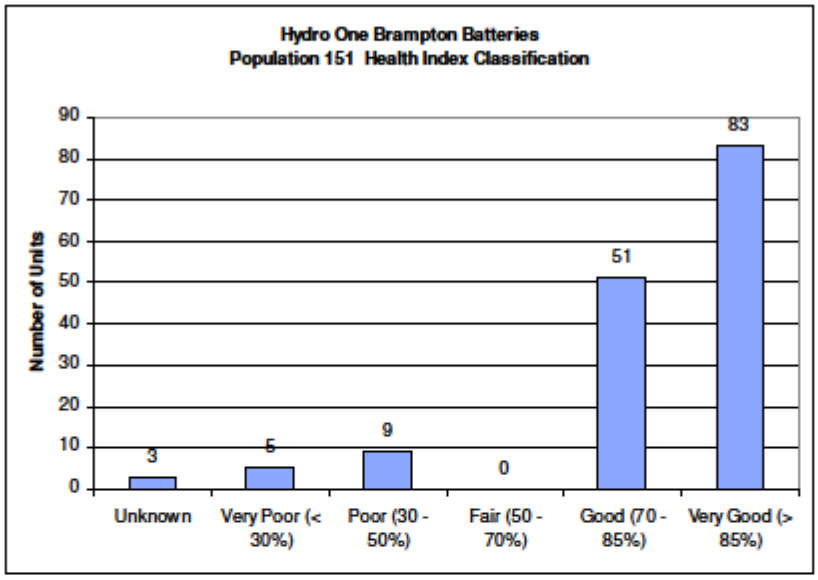


Figure 18-1 Batteries Health Index Distribution

18.6 Age Distribution

The age distribution is shown on Figure 18-2.

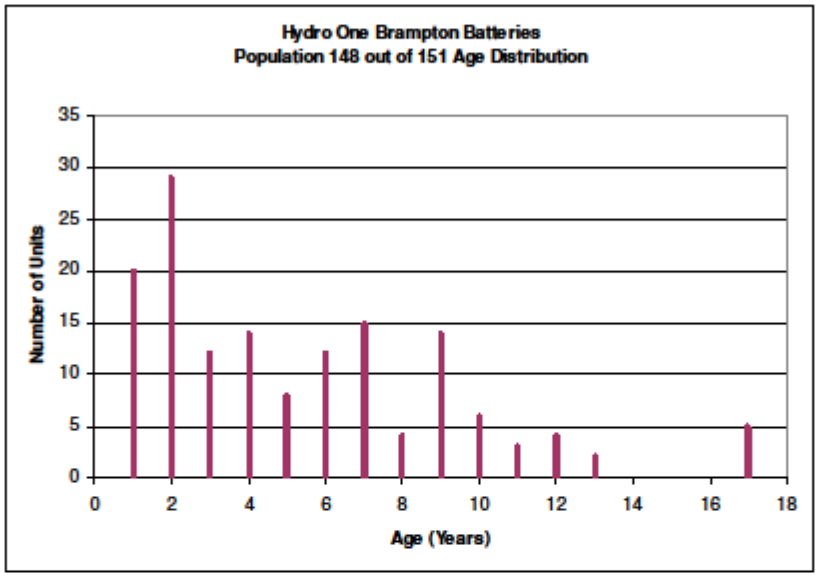


Figure 18-2 Batteries Age Distribution

18.7 Data Availability Indicator

The data availability indicator chart is not shown as only one condition parameter, age, was available.

18.8 Capital Replacement Plan

Batteries are replaced as they fail with minimal consequential risk so that a probability of failure replacement plan was developed. Assumptions and details include:

- Probability of failure parameters $\alpha = 34$ and $\beta = 0.171$ (station batteries "industry standard")
- Nominal replacement costs: $800
- Population of 151 units with 148 or 98% with data.
- Most of the battery units are relatively new and the entire population is relatively small so that probable replacements don't appear for the first four years.

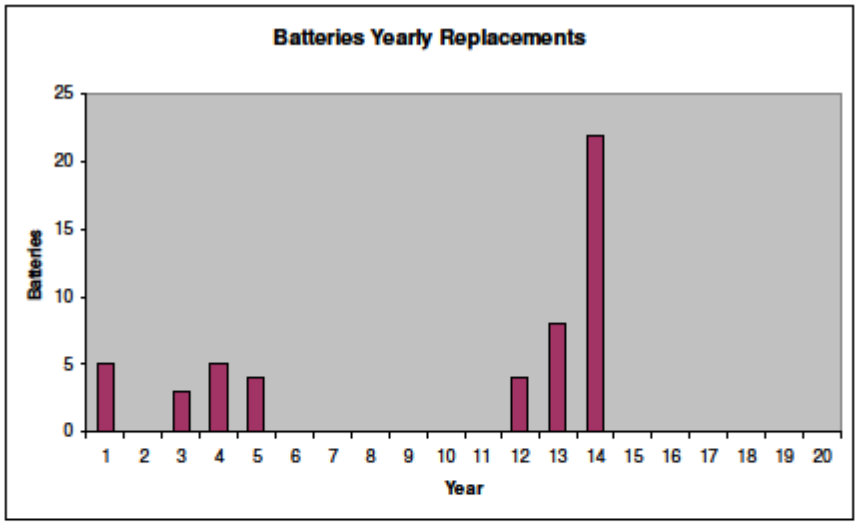


Figure 18-3 Batteries Yearly "Probable Failure" Replacements

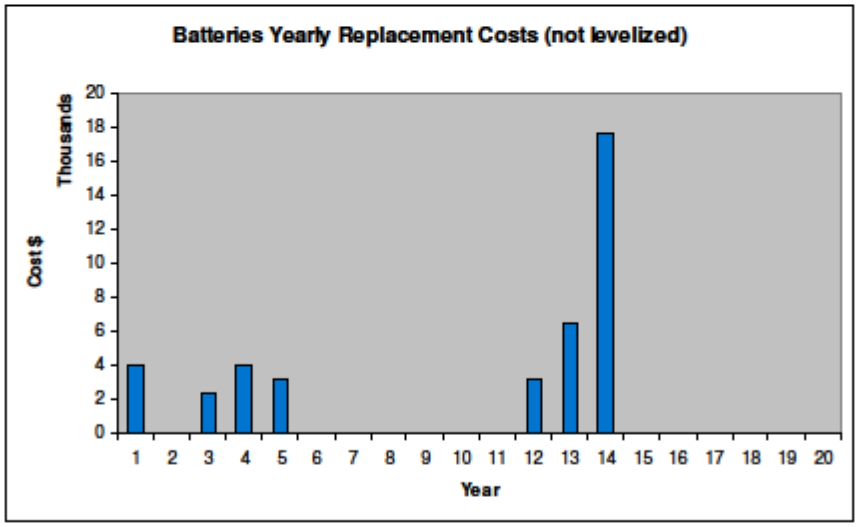


Figure 18-4 Batteries Yearly "Probable Failure" Replacement Cost

18.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement was not deemed to be necessary as the cost of batteries is a very small proportion of the capital plans for other asset categories.

18.10 Median End of Life and Extreme End of Life

The median end of life (50% have failed) and extreme end of life (99% have failed) can be determined with $\alpha = 34$ and $\beta = 0.171$. The median end of life for batteries is 21 years. The maximum end of life is 30 years.

18.11 Data Gap Closure

This section outlines the data gap for batteries, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Age

Data Gap

Type of Data Gap	Priority
Battery capacity % (measurement)	P1
Storage temperature (measurement)	P1
Cell replacement % (count)	P1
IR (CM)	P2
Battery impedance	P2
Charger (CM)	P2
Electrolyte level (CM)	P2
Discharge cycle (count)	P2
Corrosion	P3
DC ground	P3
Other CM or measurement	P3

19 UTILITY CHAMBERS

19. UTILITY CHAMBERS

HOBNI maintains 327 utility chambers. Utility Chambers or "manholes" facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. Below ground equipment vaults permit installation of transformers, switchgear or other equipment. Vaults used for transformer installation are often equipped with ventilation grates to provide natural or forced cooling.

Underground cable chambers come in different styles, shapes and sizes according to the location and application. For this analysis we identified only the broad categories depending on their use and type of construction. Precast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are cheaper to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems. Sidewalk vaults are most often located in or adjacent to pedestrian walkways.

19.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, utility chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, manhole chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers or vaults into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have a stronger effect. Therefore, a condition-based asset management program based on periodic field inspections to identify problems and rate the condition of the structure is used by many utilities. Tracking the results of these inspections will show the rate of deterioration and provide advance notice of impending work to correct any problems. Some underground chambers may only need cleaning or repairs to frames and covers or vault doors and grates, but the others may require major rebuilding of the walls and/or roof.

Manhole degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Manhole systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a manhole system. Similarly, manhole systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with utility chambers also requires evaluation in assessing the overall

condition of a manhole system. In addition to the above, for equipment vaults, the condition of ventilation grates and padlocks need to be considered in assessing overall health.

19.2 Health Index Methodology

19.2.1 Health Index Formulation

The Health Index formulation for utility chambers in this study is based on interpretation of various site inspection descriptions on the assets

$$HI = \frac{\sum_{m=1}^{7} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{7} \alpha_m (CPS_{m,max} \times WCP_m)}$$

where

m = Condition parameter m

CPS = Condition Parameter Score
WCP = Weight of Condition Parameter

α_m = Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)

Table 19-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m,max}$
1	structure	4	4
2	internal support	2	4
3	access	2	4
4	flooding	1	4
5	grounding	1	4
6	working space	3	4
7	contamination	1	4

Due to the complexity of the site inspection descriptions in this study, there is no pre-defined condition criteria for the condition parameters. Each condition parameter is assessed by manually interpreting the contents of the site inspection descriptions.

19.3 Expert Opinion

No expert opinion was provided for utility chambers.

19.4 Field Surveys

Field surveys are not available for utility chambers.

19.5 Health Index Distribution

The Health Index distribution is shown on the figure below:

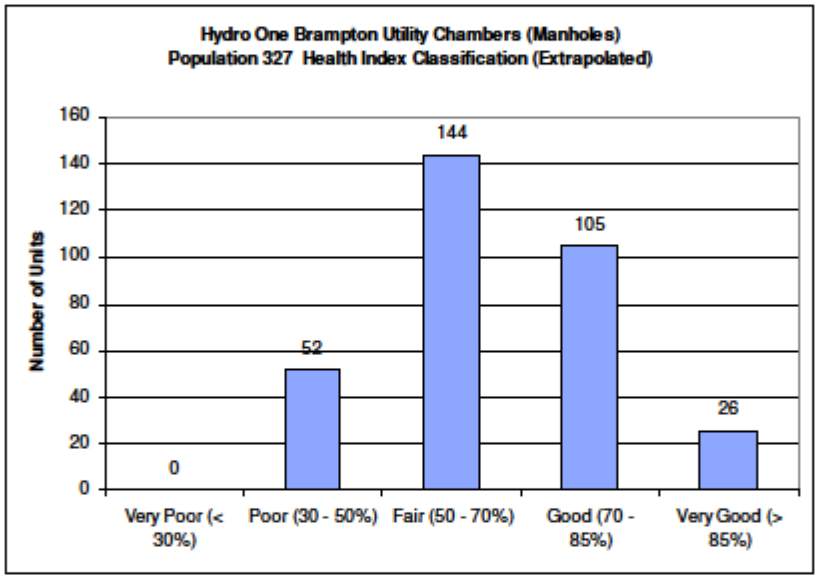


Figure 19-1 Utility Chambers Health Index Distribution

19.6 Age Distribution

No Age Distribution figure is shown as there was minimal age data available.

19.7 Data Availability Indicator

The Data Availability Indicator (DAI) is shown on Figure 19-2.

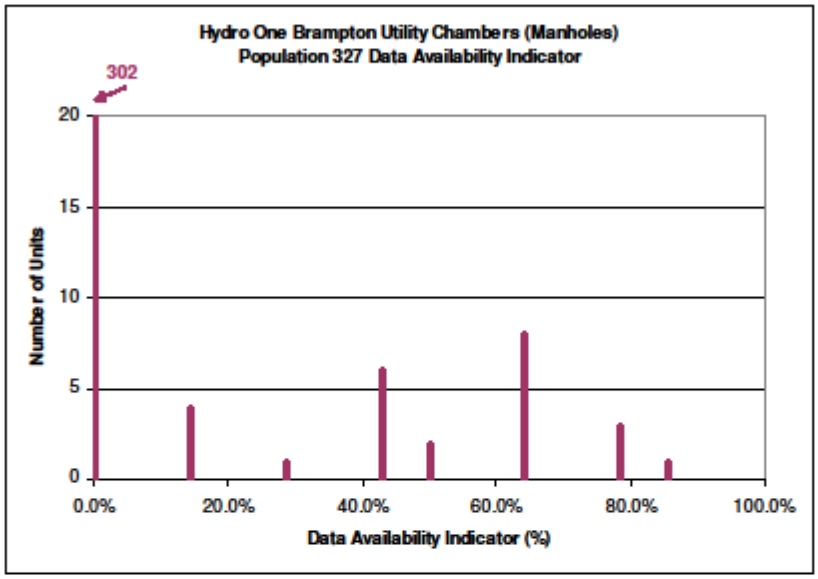


Figure 19-2 Utility Chambers Data Availability Indicator Distribution

19.8 Optimal Capital Replacement Plan

Utility chambers are a civil asset whose replacement or refurbishment is usually governed by what it contains. There were insufficient data available to suggest a refurbishment plan for these assets and the cost of replacement/refurbishment depends greatly on the contents or function (e.g vault transformer vs. cable junction) and location of each chamber.

19.9 Levelized Capital Replacement Plan

A Levelized Capital Replacement is not applicable for this asset,

19.10 Median End of Life and Extreme End of Life

The median end of life and extreme end of life are not applicable for this asset.

19.11 Data Gap Closure

This section outlines the data gap for utility chambers, as well as the priorities in filling the gap. The data gap here refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only part of the asset population is not considered as data gap and is therefore not addressed.

In the following sections, a rating of 3 scales is adopted to indicate the priority of data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Low priority	Helpful data

Data Available

The following data are provided:

- Inspection results

Data Gap

Type of Data Gap	Priority
Structure (CM)	P1
Working space (CM)	P1
Internal support (CM)	P2
Access (CM)	P2
Other CM (flooding, grounding, contamination)	P3

20 BUILDINGS

20. BUILDINGS

The assets grouped under buildings in this report include housing facilities for substations. There are 14 such buildings included in this report. While these structures must conform to a utility's functional needs they also must conform to local building codes and relevant workplace health and safety regulations.

20.1 Degradation Mechanism

While many of the comments below apply to all buildings, the report focuses on buildings housing the electrical substations, since they must meet the most stringent needs. The substation buildings, in addition to the buildings also contain the following subsystems:

Footings and Foundations provide a supporting base for substation equipment. Foundation materials usually consist of reinforced concrete. Since they have load (e.g., static, dynamic and possibly seismic) requirements based on the equipment supported, footings and foundations require proper engineering. In addition, they must conform to the elevation and height constraints of particular stations. To ensure stability over time, designs for footings and foundations also must consider environmental issues such as local climate and soil conditions.

Grounds and Landscaping provide a pleasant environment for workers and the substation's neighbours. Landscaping also aids in controlling soil erosion, maintaining overall site cleanliness, and facilitating a safe and efficient workplace.

Surface Stone is required in outdoor substation yards to provide drainage and safety coordination for step and touch potentials during ground faults

Spill Response and Containment are required to contain spilled materials during equipment failures and minimize environmental harm

Sumps and Sump Pumps are employed wherever the potential exists for water build-up. For example, sump pumps can help keep basement facilities dry or clear water build-up in spill containment systems. Sump pumps are particularly critical in low water table areas.

Lifting Equipment is installed in buildings to facilitate maintenance activities. Lifting equipment ranges from small hoists that assist in managing spare parts' inventories to overhead cranes. In some cases, lifting equipment in substations plays an important role in fast restoration of power following equipment failures.

Buildings at substations house electrical equipment and serve as a base for administrative and service work. The health and condition of buildings is significantly impacted by environmental conditions, particularly rain, wind and snow storms. Because of the presence of electrical equipment, the potential for water ingress presents a particular concern for these assets. Thus, buildings must be weatherproof. Regular preventative maintenance, with occasional major refurbishment of roofs, windows and doors, helps ensure the long-term viability and integrity of buildings. Generally, for well-maintained buildings, operational issues dictate the asset's longevity.

20.2 Health Index Methodology

A Heath Index formulation was not in the project scope for buildings. A site inspection was conducted.

20.3 Expert Opinion

No expert opinion was requested for Buildings.

20.4 Field Surveys

As part of the asset condition assessment, Kinectrics conducted a visual inspection of the power system physical assets. This was to confirm the accuracy of the asset lists and the condition information provided to Kinectrics, and to provide an assessment of the condition of assets for which no data was available. Assets were visually inspected and rated A, B, C, D, N, or U where:

A = New Condition. No signs of wear or age.
B = Some minor signs of wear or age. No maintenance required.
C = Definite signs of wear or age. Some minor maintenance, such as painting, may be required.
D = At end of life or major maintenance required.
N = Not applicable.
U = Unknown

The results of the field survey are shown below:

Table 20-1 Station Buildings Survey

	MS 14	MS 10	MS1	MS 2	MS 19	MS 20	MS 22	MS 21	MS 3
Condition of structure (roof, walls)	B	C	B	C	B	B	B	B	C
Condition of doors and locks	B	B	B	C	B	B	B	B	B
Condition of Lightning	B	B	B	C	B	B	B	B	B
Overall Building Condition	B	B	B	C	B	B	B	B	C
		water leaking under wall, cracks between concrete blocks	old but seems OK			metering shed		metering shed	paint peeling badly

The site survey ratings are summarized as follows:

Table 20-2 Summary of Station Buildings Survey Ratings

	# A	#B	#C	#D
Condition of structure (roof, walls)	1	6	3	0
Condition of doors and locks	1	8	1	0
Condition of Lightning	1	8	1	0
Overall Building Condition	1	7	2	0
sum	4	29	7	0
% of known	10.0%	72.5%	17.5%	0.0%

20.5 Health Index Distribution

The Health Index distribution is not available for this asset.

20.6 Age Distribution

The age distribution is not available for this asset.

20.7 Data Availability Indicator

The Data Availability Indicator (DAI) is not available for this asset.

20.8 Optimal Capital Replacement Plan

The Optimal Capital Replacement Plan is not available for this asset.

20.9 Levelized Capital Replacement Plan

The Levelized Capital Replacement Plan is not available for this asset.

20.10 Median End of Life and Extreme End of Life

The median end of life and extreme end of life are not applicable for this asset.

20.11 Data Gap Closure

The data gap information is not applicable for this asset.

21 CONCLUSIONS AND RECOMMENDATIONS

21. CONCLUSIONS AND RECOMMENDATIONS

1. The availability of condition data collected by HOBNI is compatible with that of comparable size utilities and the existing data collection should continue. Additionally, there is a need to close existing data gaps in a prioritized manner as recommended in this report, particularly for the assets that are replaced proactively, such as:
    - Municipal Station Transformers, for example, start recording monthly peak loading and ensure that the condition data are available in electronic format.
    - SF6 circuit breakers, including the 22 new ones at Jim Yarrow TS
    - Vacuum breakers, including the new ones that will replace existing Oil breakers and Magnetic breakers
    - XLPE Primary Feeder and Distribution cables

2. For the assets replaced reactively, relevant information, such as age, test results if available, experience with certain manufacturer(s) or designs, problem locations, etc., also needs to continue to be collected in order to forecast number of future expected failures. Particular attention should be given to closing data gaps for:
    - Wood pole structures, including wood pole testing
    - Utility Chambers (information on only 8% of the total population was available)
    - Load Interrupting Switches

3. No condition information is available for the overhead conductors. It is recommended that HOBNI puts in place a conductor testing program that will allow us to determine condition of overhead conductors in the HOBNI's distribution system. The program should include:
    - Testing samples for torsional ductility (number of turns before conductor breaks)
    - Testing remaining Rated Tensile Strength (RTS) at several locations per year using in-situ methodology
    - Testing conductor connectors
    - Recording extent of corrosion of hardware during routine maintenance inspections

4. A condition data audit should be carried out annually to determine a progress being made in closing the data gaps.

5. Based on the Asset Condition Assessment results, the levelized capital replacement cost over the next 5 years varies between $9.26M and $12.2M. Of specific note is the need to:
    - significantly increase investments in replacing Primary Feeder and Distribution XLPE cable. The overall amount may be somewhat lower than recommended because at some locations primary feeders and distribution cables share the same trench and would be replaced at the same time thus reducing the cost;
    - Replace the remaining 3 oil circuit breakers over the next 3-4 years;
    - Start replacing Municipal Station Transformers at a rate of 2/year for the next 4 years and then 1/year for another 4 years.

6. HOBNI's maintenance practices are compliant with DSC requirements and should be further improved through collection of relevant asset condition information.

7. The levelized capital replacement levels should be used as a starting point in using the prioritization methodology for determining the optimal investment levels within the overall business plan.

8. This condition assessment should be used as a reference and periodic asset condition assessment should be performed at regular intervals to ensure that a) the replacement investments are sufficient to at least maintain and perhaps even improve assets condition and b) that adequate condition information is being collected.

EXHIBIT 2 TAB 7

SERVICE QUALITY AND RELIABILITY PERFORMANCE

SERVICE QUALITY INDICATORS SUMMARY

Hydro One Brampton has consistently exceeded the Board's Service Quality Indicators, as illustrated in Schedule 1.1 on the following pages.

Hydro One Brampton has targeted to maintain its performance at levels that exceed the Board's standards in 2010 and 2011.

SERVICE QUALITY INDICATORS FOR 2007, 2008 and 2009

REPORTED SERVICE QUALITY INDICATORS

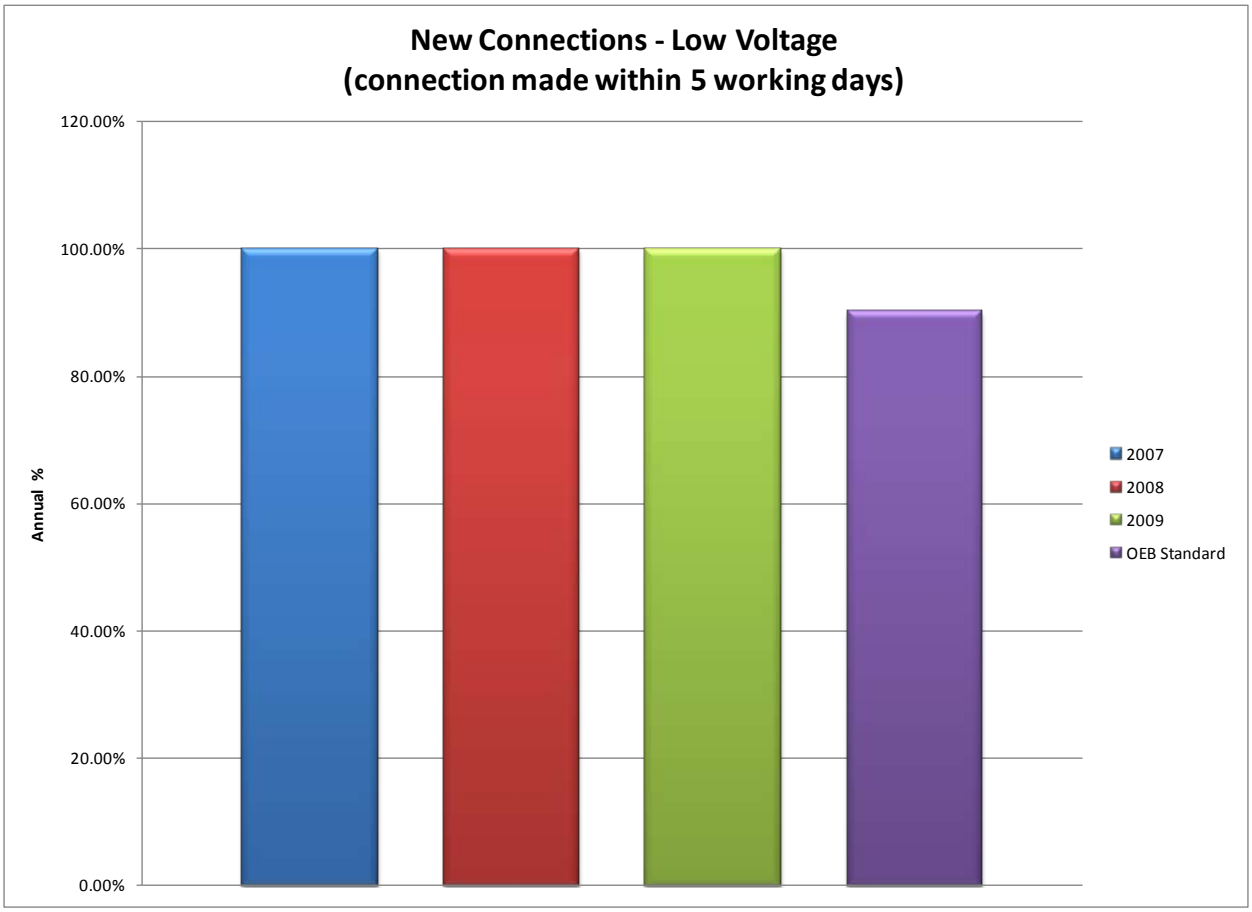


Figure 1: New Connections - Low voltage

New Connection – Low Voltage (LV)

The percentage of new low voltage (<750 Volts) connection requests where the connection is made within five working days of all applicable service conditions is being satisfied at least 90% of the time.

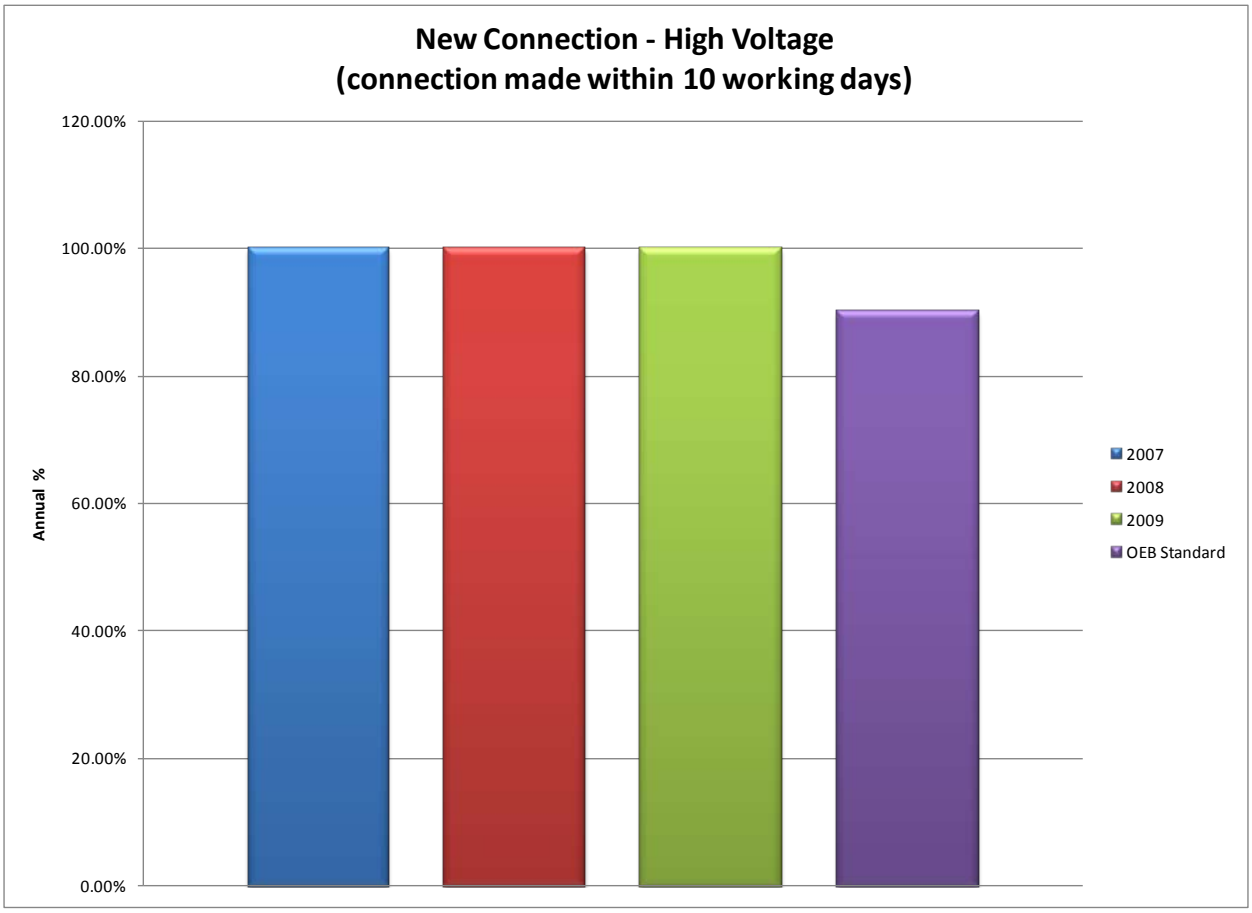


Figure 2: New Connection - High Voltage

New Connection – High Voltage (HV)

The percentage of new high voltage (>750= Volts) connection requests where the connection is made within ten working days of all applicable service conditions is being satisfied at least 90% of the time.

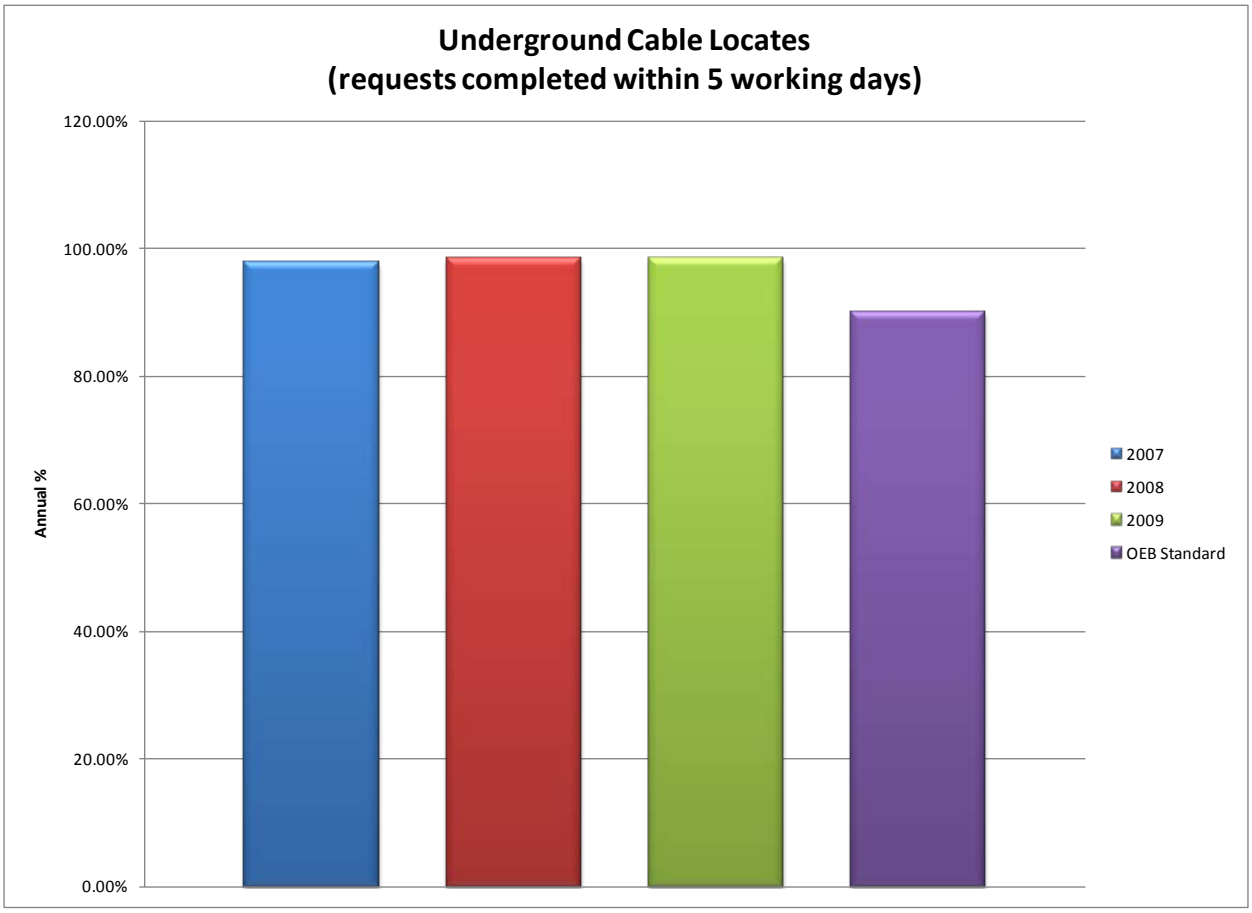


Figure 3: Underground Cable Locates

Underground Cable Locates (UCL)

The percentage of requests for cable locates that are completed within five working days (of the initial date of the request or, if the customer so designates, a specific requested date) is being satisfied at least 90% of the time.

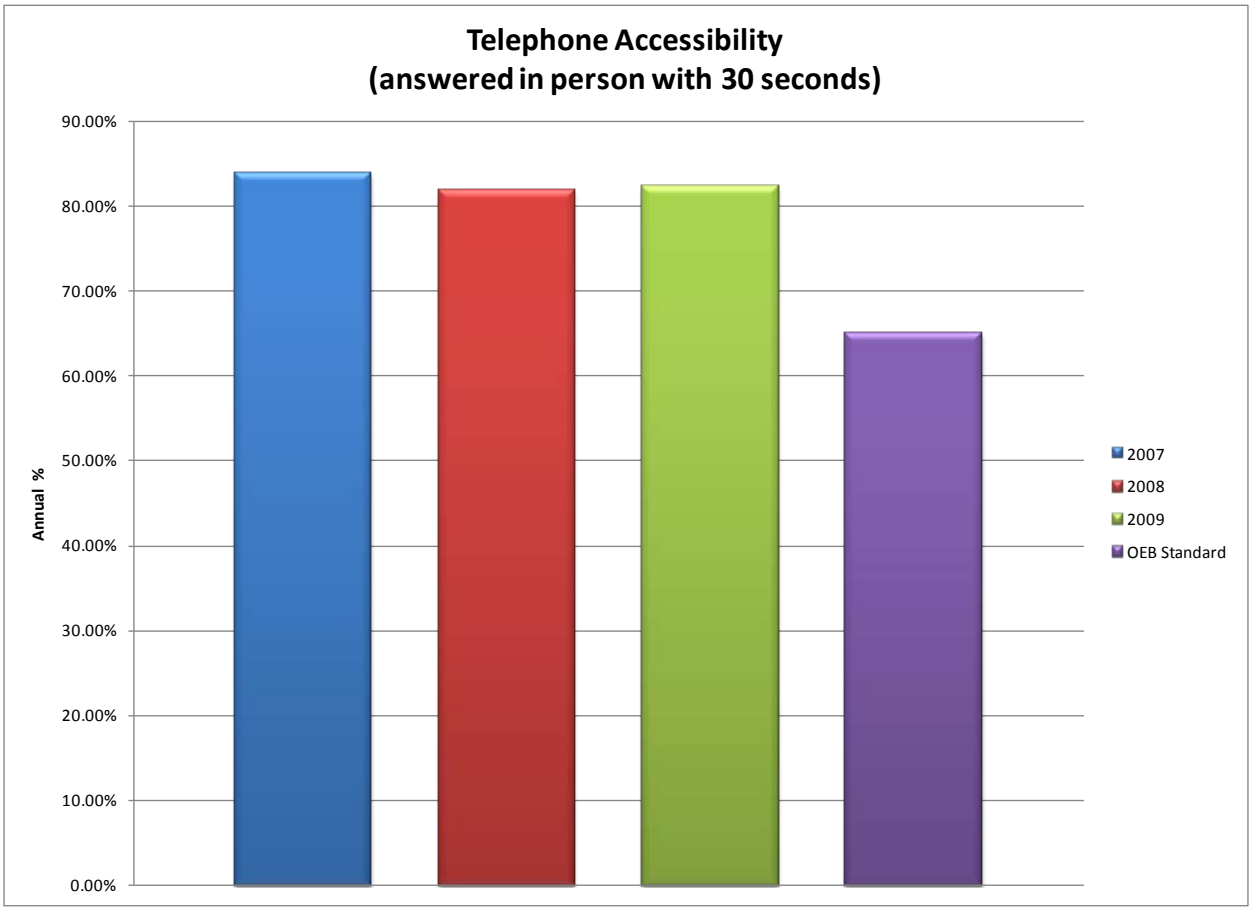


Figure 4: Telephone Accessibility

Telephone Accessibility

The percentage of calls to the Utility's general inquiry number that are answered in person within 30 seconds is being satisfied at least 65% of the time.

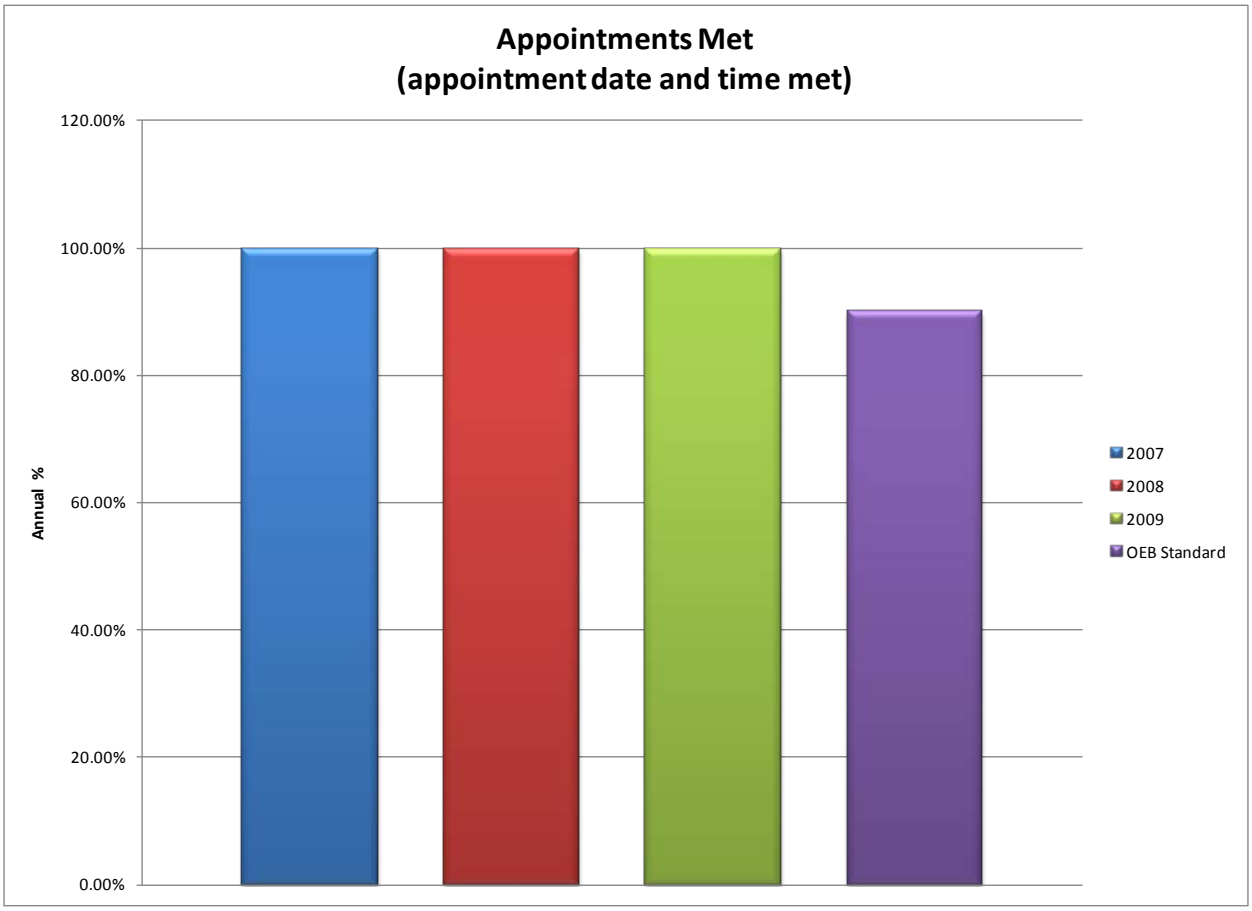


Figure 5: Appointments Met

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment is scheduled as required and the appointment date and time is satisfied at least 90% of the time.

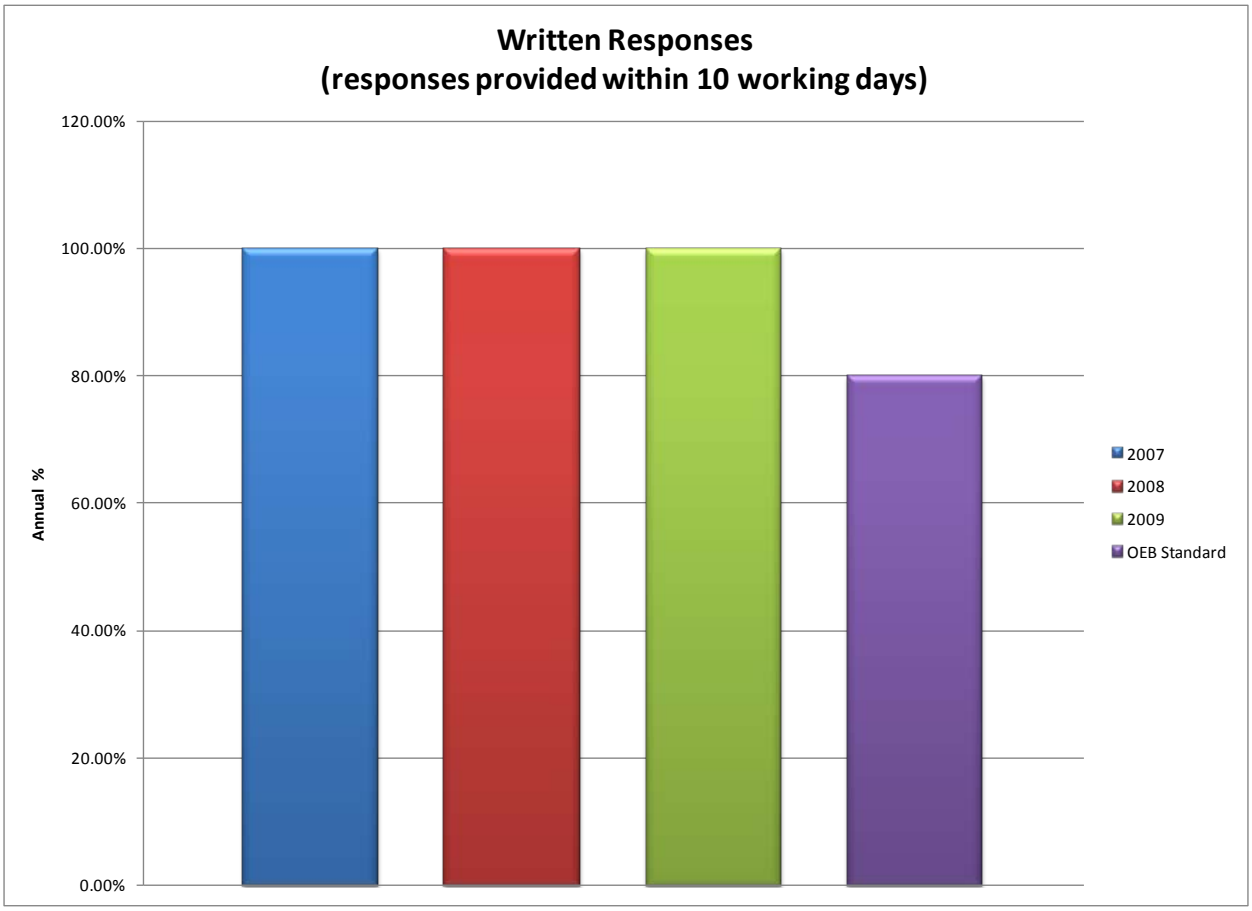


Figure 6: Written Responses

Written Responses to Enquiries

The percentage of customer enquiries requiring a written response where the response is provided within ten working days of the receipt of the enquiry at least 80% of the time.

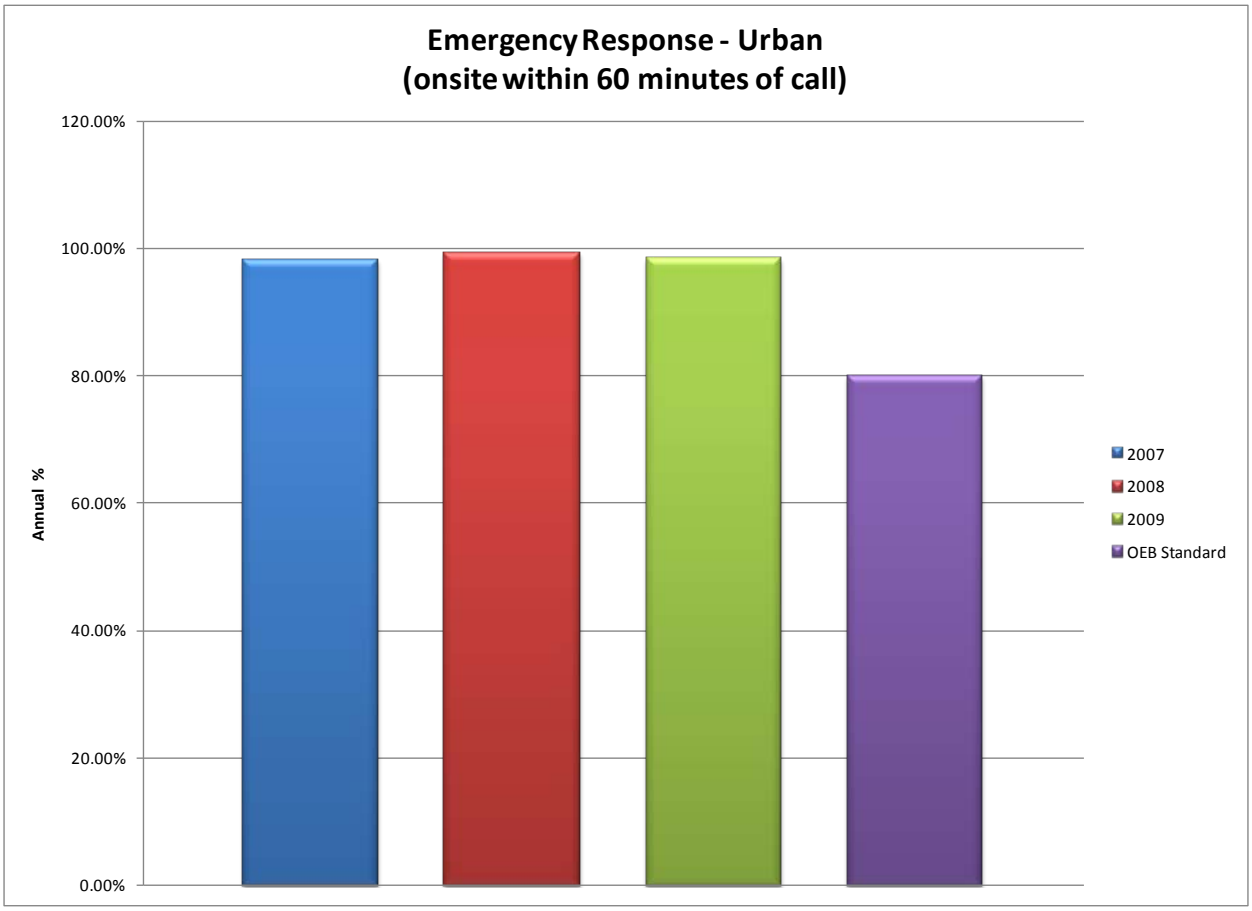


Figure 7: Emergency Response - Urban

1 ***Emergency Response – Urban***

2 The percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is
3 on site within 60 minutes of the call is being satisfied at least 80% of the time. The definition of
4 "rural" and "urban" should correspond to the municipality's definition.

SYSTEM RELIABILITY SUMMARY

Hydro One Brampton tracks service reliability statistics SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) including and excluding Hydro One related incidents.

The Service Reliability Indices for 2009 exceeded the averages for each of the previous years. Hydro One Brampton had the capability to capture the information required to file MAIFI for the 2009 year as indicated in **Table 1** on the following page.

Hydro One Brampton's system reliability is such that on average, customers are never without service for more than 54 minutes in a year. In addition, Hydro One Brampton's customers, on average, do not experience more than 1.3 interruptions in service in a year and when an interruption occurs, Hydro One Brampton's average restoration time is 42 minutes. Overall, in 2009, Hydro One Brampton's system reliability index was 0.7416, meaning that Hydro One Brampton's distribution system was available to supply customers 99.9999% of the time during that year.

The reliability indicators assist in developing the Sustainment Driven programs within the Asset Management Plan. Sustainment Driven Investment projects involve replacement of assets at end of life, i.e. transformer replacements, subdivision rebuilds and pole replacements. The purpose of maintaining the long term and short term functionality of assets is to ensure public and employee safety, comply with regulations and contractual requirements, and provide a level of reliability that is aligned with corporate objectives.

Sustainment Driven investments made over the past few years appear to be yielding positive results – reliability has improved. Significant work has taken place in specific areas where the infrastructure was visibly aging, or where trend analysis indicated deficiencies.

SYSTEM RELIABILITY PERFORMANCE FOR 2007, 2008 & 2009

Table 1: Reported Service Reliability Indices

Reported Service Reliability Indices						
SRI	**2007 Actual**		**2008 Actual**		**2009 Actual**	
	with Code 2 Outages	**Excluding Code 2 Outages**	**with Code 2 Outages**	**Excluding Code 2 Outages**	**with Code 2 Outages**	**Excluding Code 2 Outages**
SAIDI (System Average Interruption Duration Index)	1.26	1.12	0.77	0.75	0.79	0.72
SAIFI (System Average Interruption Frequency Index)	1.85	1.45	1.12	0.96	1.27	1.03
CAIDI (Customer Average Interruption Duration Index)	0.68	0.77	0.69	0.78	0.62	0.70
MAIFI (Monetary Average Interruption Frequency Index)	N/A	3.16	N/A	3.39	N/A	4.37

Service reliability indices measure system outage statistics. The monitoring and reporting of service reliability indices are intended to encourage distributors to maintain or improve the existing service reliability performance of its electrical distribution system. A graphical representation of Hydro One Brampton's service reliability indices are detailed in the following pages. Each index is detailed with and without Code 2 Outages.

Code 2 Outages, as defined by the Board, include a loss of supply where customer interruptions are caused due to problems in the bulk electricity supply system (Hydro One Transmission).

System Average Interruption Duration Index (SAIDI)

SAIDI is an indicator of system reliability that expresses the length of outage customers experience in the year on average. All planned and unplanned interruptions of one minute should be used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served, and is expressed as follows:

$$SAIDI = \frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

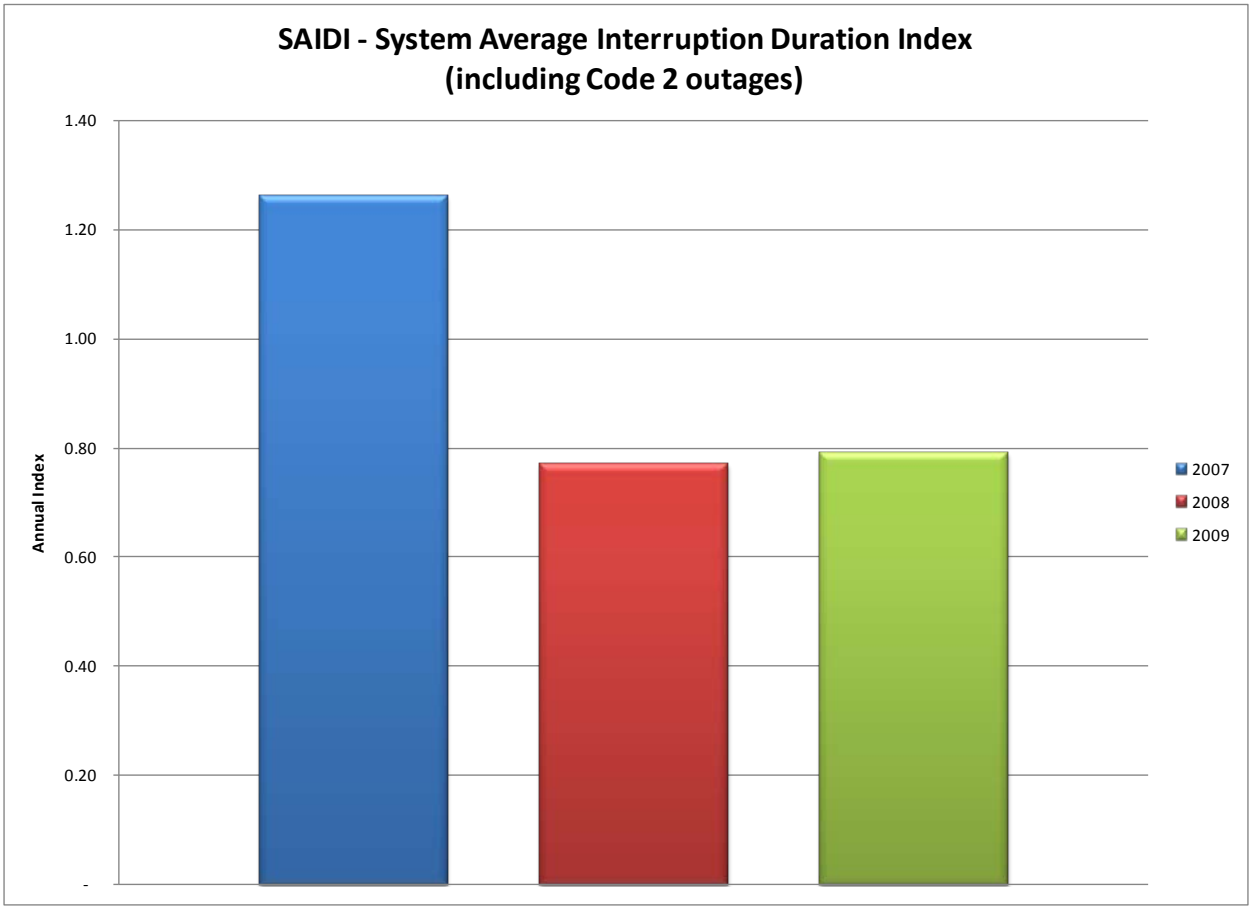


Figure 1: SAIDI Index (including Code 2 outages)

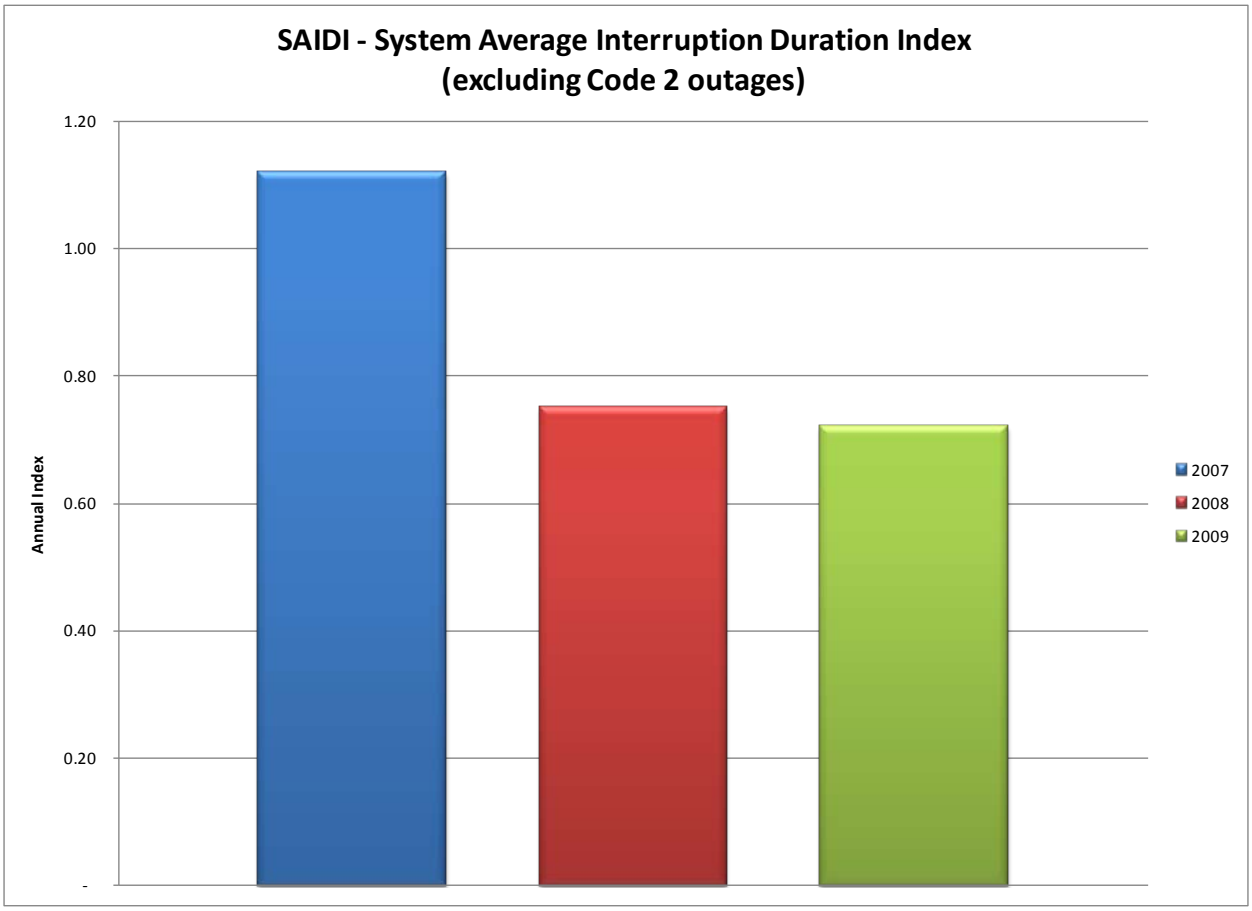


Figure 2: SAIDI (excluding Code 2 outages)

System Average Interruption Frequency Index (SAIFI)

SAIFI is an indicator of the average number of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as the number of interruptions normalized per customer served, and is expressed as follows:

$$SAIFI = \frac{\text{Total Customer Interruptions}}{\text{Total Number of Customers Served}}$$

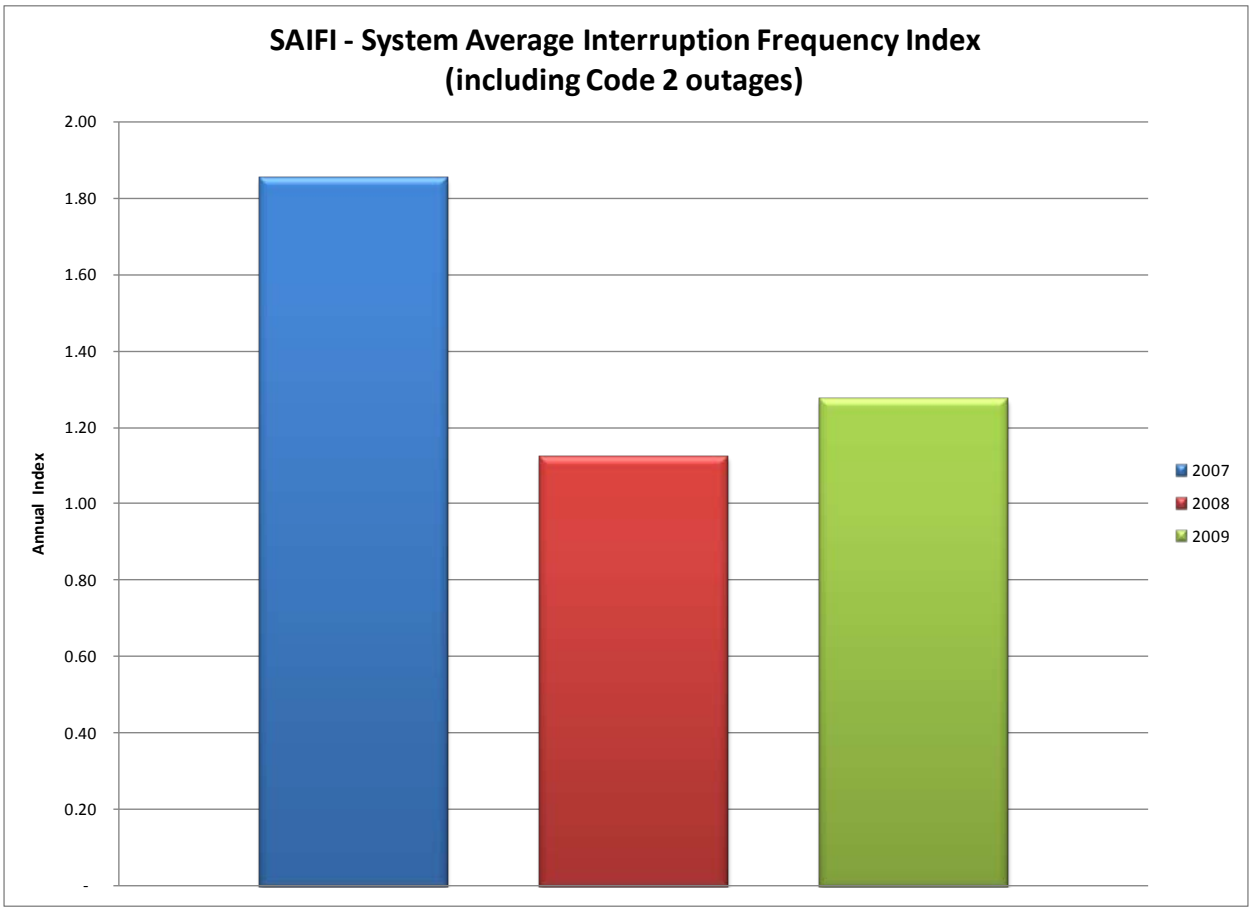


Figure 3: SAIFI (including Code 2 outages)

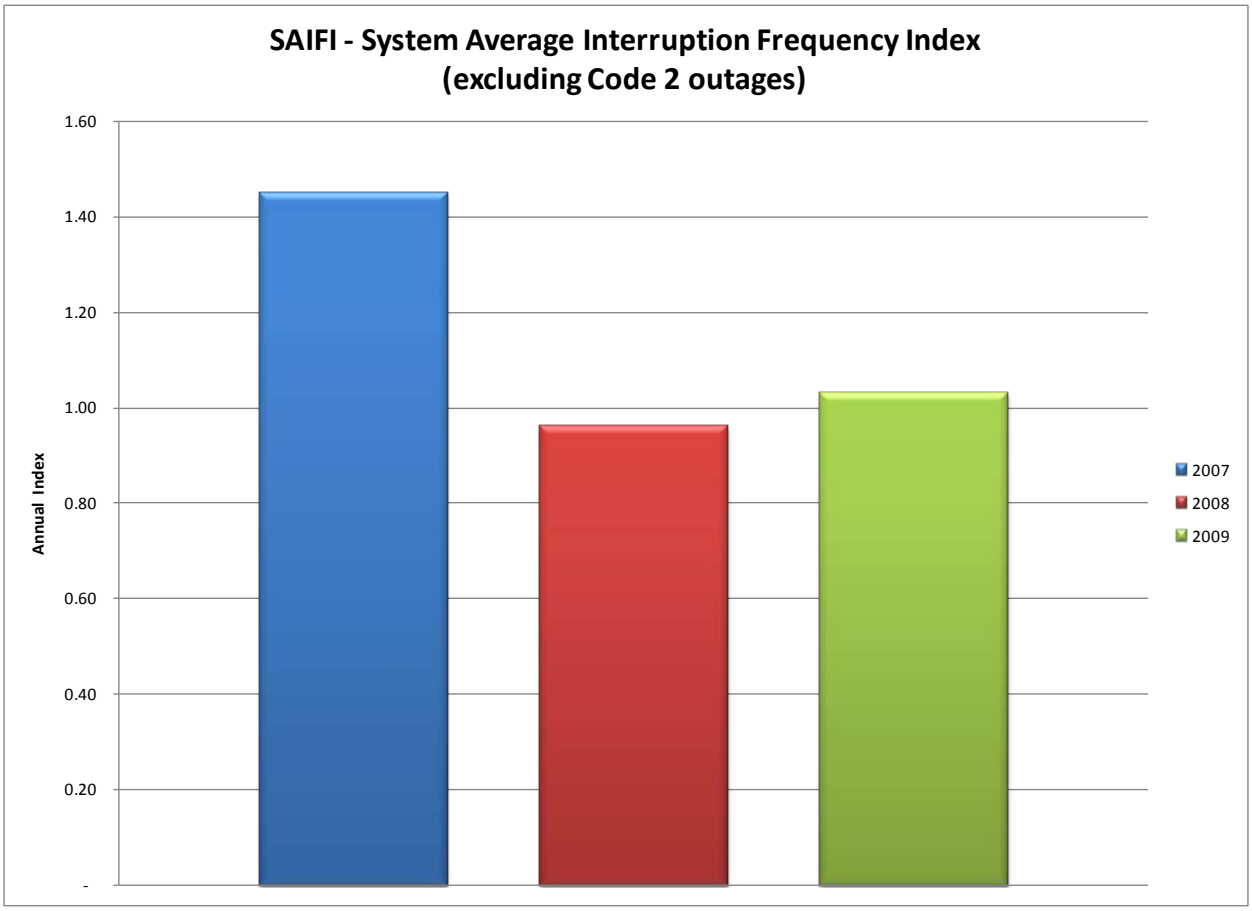


Figure 4: SAIFI (excluding Code 2 outages)

Customer Average Interruption Duration Index (CAIDI)

CAIDI is an indication of the speed at which power is restored. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as the average duration of interruptions in the year, and it is expressed as follows:

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{Total\ Customer\ Hours\ of\ Interruption}{Total\ Customer\ Interruptions}$$

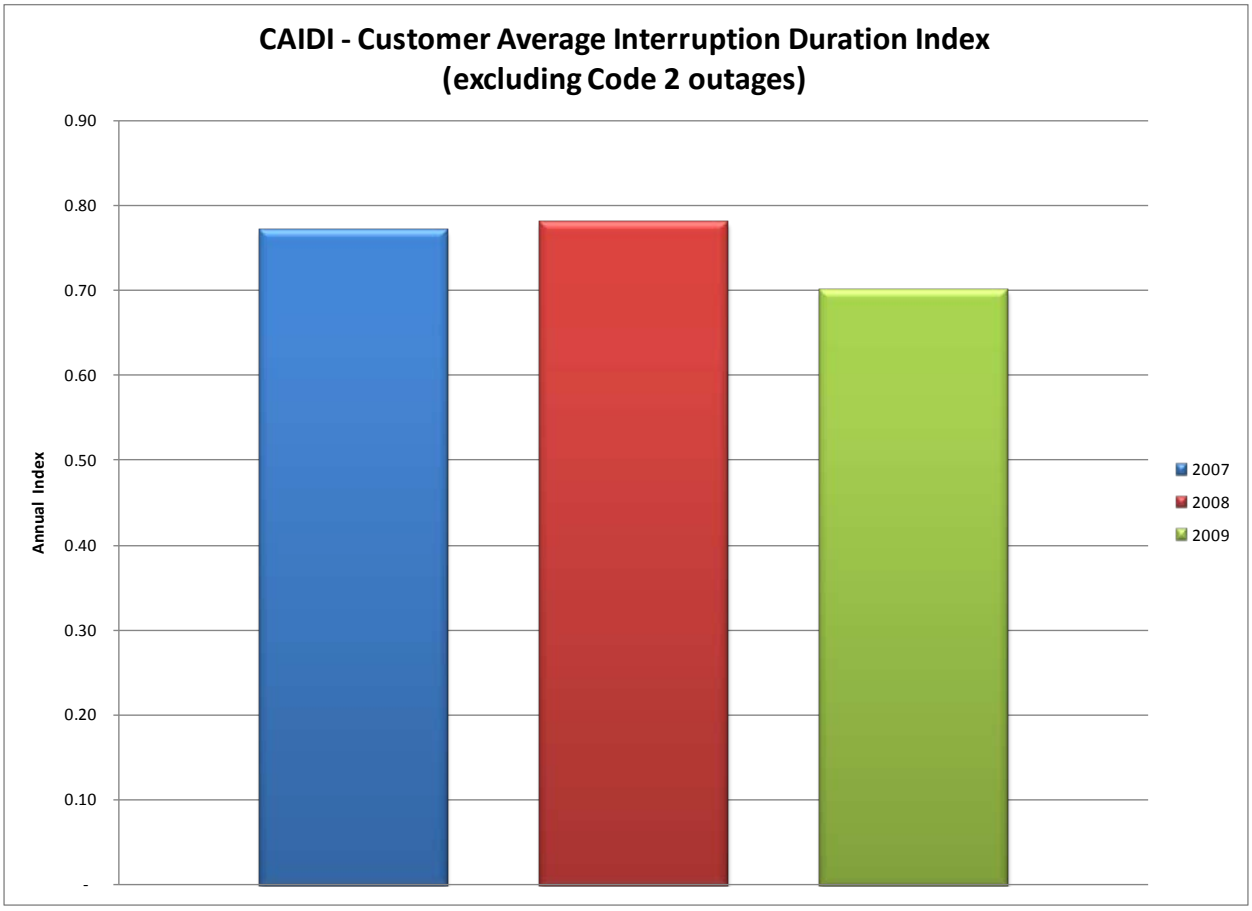


Figure 5: CAIDI (excluding Code 2 outages)

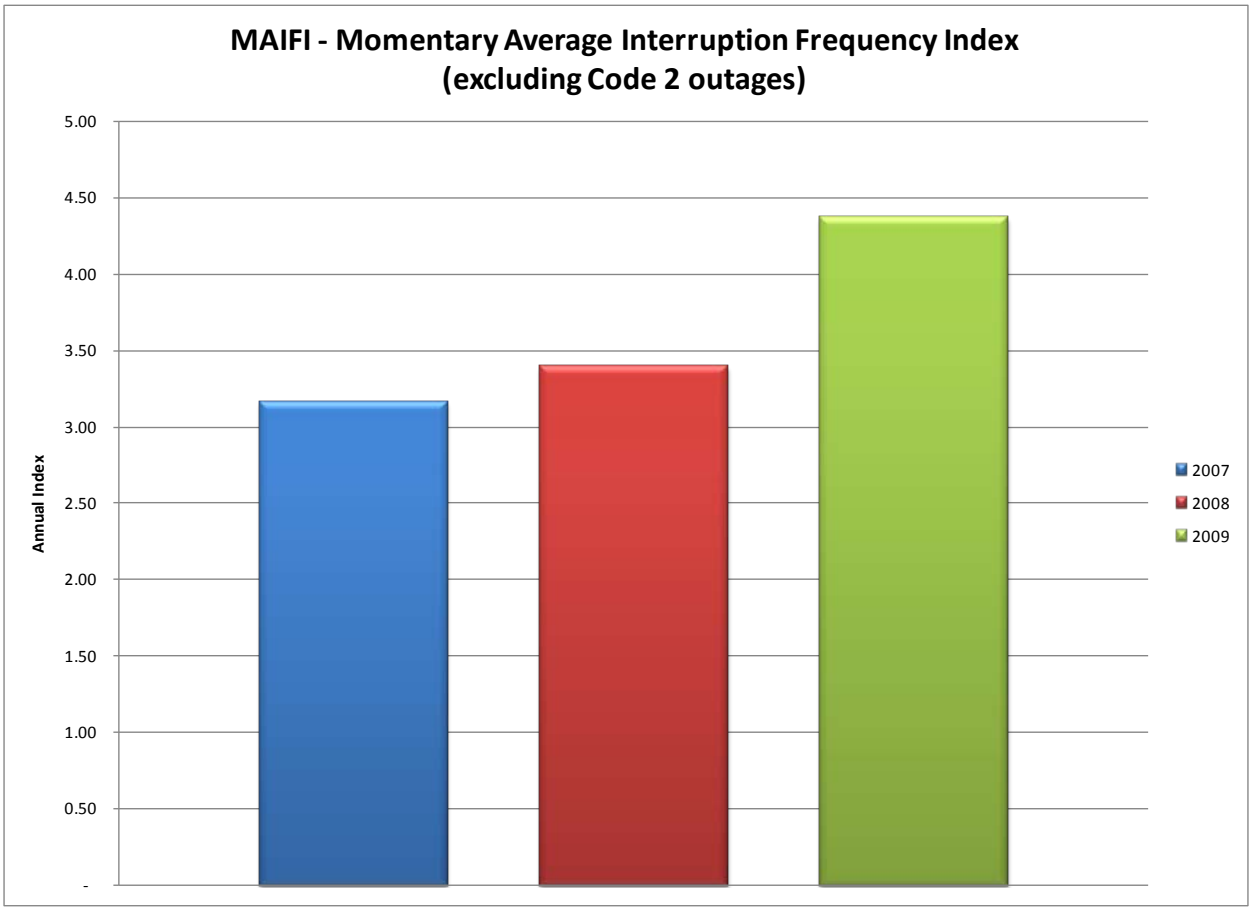


Figure 6: MAIFI (excluding Code 2 outages)

Momentary Average Interruption Frequency Index (MAIFI)

MAIFI is an indicator of the average number of momentary interruptions each customer experiences. All planned and unplanned momentary interruptions should be used to calculate this index. MAIFI is defined as the number of momentary interruptions normalized per customer served, and is expressed as follows:

$$MAIFI = \frac{\text{Number of Momentary Interruptions for all Customers}}{\text{Total Number of Customers Served}}$$

EXHIBIT 3

OPERATING REVENUE

EXHIBIT 3 TAB 1

OVERVIEW OF OPERATING REVENUE

SUMMARY OF OPERATING REVENUE

Hydro One Brampton's operating revenue for 2006 (Board Approved and Actual), 2007 to 2009 Actual, 2010 Bridge Year and 2011 Test Year is presented in this Exhibit. This Exhibit also provides weather normalized billing determinant forecasts for the 2010 Bridge Year and the 2011 Test Year, and the methodology used to establish those forecasts. The forecasted volumes are used as the denominator volumes to establish Distribution Rates based on total Revenue Requirement less the Revenue Offsets as the numerator dollar values. The rates established multiplied by the billing determinants equal the Throughput Revenues that are then compared year over year to determine the revenue variance analysis by rate class and the material variances are explained in this exhibit as well. The Other Revenues are also presented in this exhibit with year over year comparisons and variance analysis. As shown in Table 1 below, HOBNI's 2011 base distribution revenue is $66,553,916. (Note the difference to the proposed revenue requirement of $66,581,755 relates to rounding differences caused by limits of two decimal points for the monthly fixed service charges and 4 decimal points for variable distribution rates.)

COMPARABILITY OF HISTORICAL REVENUE IMPACTED BY SMART METERS

Given that Hydro One Brampton is filing for the inclusion of Smart Meter costs (incurred to December 31, 2009) in rate base and Revenue Requirement, the Company has included the following financial transaction data in its' 2006 to 2010 Regulatory Trial Balances retroactively:

- Smart Meter Capital Expenditures/ Accumulated Depreciation and Depreciation Expense;
- Smart Meter Operating Expenditures;
- Smart Meter Revenue Requirement;
- Stranded Meter Capital Costs/ Accumulated Depreciation and Depreciation Expense

The inclusion of the above enabled Hydro One Brampton to include Smart Meter costs in the determination of Revenue Requirement for 2011. By including all costs and revenues relating to smart meters installed to the end of December 31, 2009 has permitted HOBNI to establish a

comparative basis for financial information for the 2006 to 2009 Historical, and the 2010 Bridge and 2011 Test Years. For consistency purposes HOBNI has included Smart Meter Riders in the unit rates used for comparative throughput analysis

The Operating Revenue Summary below provides a comparison of total revenue from 2006 OEB approved year to the 2011 Test Year.

OPERATING REVENUE TABLE

Table 1: Operating Revenue Throughput Analysis

Description	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test Year At Existing Rates	2011 Test Year At Proposed Rates
Distribution Revenue:								
Residential	28,804,232	30,932,917	32,750,248	33,477,545	34,505,113	33,965,375	32,611,130	33,913,877
General Service < 50 kW	6,753,149	6,947,577	7,271,249	7,120,105	7,141,502	7,056,544	7,083,429	6,609,534
General Service > 50 kW	8,234,737	8,721,459	8,926,700	9,031,596	9,116,566	8,800,962	8,955,510	10,658,221
Intermediate	9,443,369	10,229,530	10,037,773	9,531,806	9,022,443	8,757,052	8,812,785	8,814,322
Large Use (> 5000 kW)	1,494,553	1,978,758	2,176,059	2,458,612	2,421,613	2,269,815	2,364,211	2,134,272
Street Lighting	132,445	158,530	171,740	179,273	183,904	187,121	195,409	1,883,527
Unmetered Scattered Load	0	114,457	109,696	108,956	108,693	104,345	102,209	127,659
Sub-Total	**54,862,485**	**59,083,229**	**61,443,465**	**61,907,893**	**62,499,835**	**61,141,214**	**60,124,683**	**64,141,412**
Low Voltage Adder to Rates	**(94,500)**	**(65,797)**	**(67,103)**	**(68,221)**	**(67,065)**	**(65,742)**	**(67,464)**	**0**
Gross Distribution Revenue From Rates Charged	**54,767,985**	**59,017,432**	**61,376,363**	**61,839,671**	**62,432,770**	**61,075,472**	**60,057,219**	**64,141,412**
Other Revenue:								
SSS Administration Revenue	247,340	280,415	311,193	314,944	309,221	312,834	316,281	316,281
Retail Services Revenue	240,751	260,051	293,177	305,716	285,754	350,000	310,000	310,000
Service Transaction Requests (STR) Revenues	1,433	12,485	20,825	13,850	4,200	25,000	5,000	5,000
Rent From Electric Property	205,775	752,415	733,319	575,118	557,520	540,030	498,000	498,000
Late Payment Charges	866,886	1,090,020	1,220,696	1,219,746	1,314,408	1,310,000	1,450,331	1,450,331
Miscellaneous Service Revenue	842,243	1,348,713	1,458,177	1,299,510	1,107,039	1,188,970	1,152,000	1,152,000
Miscellaneous Non-Operating Income	451,223	824,249	52,357	10,106	184,973	150,000	252,000	252,000
Interest Income	152,787	524,343	481,318	322,429	26,803	6,680	2,799	2,799
Sub-Total	**3,008,438**	**5,092,690**	**4,571,062**	**4,061,417**	**3,789,918**	**3,883,514**	**3,986,412**	**3,986,412**
Gross Revenues Before Transformer Credit	**57,776,423**	**64,110,122**	**65,947,425**	**65,901,089**	**66,222,688**	**64,958,986**	**64,043,630**	**68,127,824**
Payments to Hydro One For LV Charges	**94,500**	**65,797**	**67,103**	**68,221**	**67,065**	**65,742**	**67,464**	**0**
Less: Transformer Credits	**(1,468,274)**	**(1,561,629)**	**(1,581,138)**	**(1,576,798)**	**(1,497,160)**	**(1,463,795)**	**(1,504,282)**	**(1,573,908)**
Total Operating Revenue	**56,402,648**	**62,614,289**	**64,433,389**	**64,392,512**	**64,792,593**	**63,560,933**	**62,606,813**	**66,553,916**

* Historical actual normalized throughput quantities and actual customer/connection counts for year multiplied by rates in effect for respective rate year.

Note: This revenue analysis is net of transformer allowances credited to eligible customers.

EXHIBIT 3 TAB 2

WEATHER NORMALIZED VOLUME FORECASTS

LOAD FORECASTING OVERVIEW

In the following section and throughout the application references to Hydro One Brampton's two General Service demand billed customer classes have been identified using variations of the names of the customer classes. Although the customer class names as shown in the "Tariff of Rates and Charges" are the approved customer class names other variations of these customer class names some of which noted below have been used in this application but have the same meaning:

GENERAL SERVICE 50 to 699 kW - General Service > 50 kW, General Service > 50 kW - Regular, GS > 50, or GS > 50 – Regular, GS > 50 to 699 kW,

GENERAL SERVICE 700 to 4,999 kW – GS > 50 SERVICE 700 to 4,999 kW Service > 50 kW – Intermediate, GS > 700 to 4,999 kW

This evidence has been included to outline the process used by Hydro One Brampton to prepare the weather normalized load and customer/connection forecast. This forecast is used to determine the proposed distribution rates. Hydro One Brampton has reviewed the Multifactor Regression and Normalized Average use per Customer (NAC) models as described in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications. Hydro One Brampton has elected to use a Multifactor Regression model similar to the one used by Toronto Hydro Electric System Ltd in its 2008, 2009, and 2010 rate application (EB-2009-0139). A similar method was approved by the Board for the following 2010 cost of service applications:

- Burlington Hydro Inc. (EB-2009-0259)
- Oakville Hydro Electricity Distribution Inc. (EB-2009-0271)
- Veridian Connections Inc. (EB-2009-0140)

Hydro One Brampton has used the same regression analysis methodology as the distributors mentioned above to determine a prediction model. Regarding the overall process of load forecasting, Hydro One Brampton is of the view that conducting a regression analysis on historical purchases to produce an equation that will reasonably estimate future purchases is appropriate.

Hydro One Brampton maintains records on the monthly data relating to the exact kWhs purchased from the IESO for use by Hydro One Brampton customers. In a regression analysis

these purchases can be related to other monthly explanatory variables, i.e. heating degree days, cooling degree days, and number of peak hours. The result of the regression analysis determines an equation that predicts future purchases based on these explanatory variables. This prediction model is used as the basis to forecast the total level of weather normalized purchases for Hydro One Brampton for the Bridge and Test Years. The total purchases are then converted to the values predicted to be billed to each rate class. A detailed explanation of this process is provided later on in this evidence.

During the review process of the 2009 cost of service applications, Interveners expressed concerns regarding the load forecasting weather normalization process. Interveners suggested that weather normalization should be conducted on an individual rate class basis with the regression based on monthly retail kWh by rate class. In response to this suggestion, Hydro One Brampton conducted the regression for each rate class. Hydro One Brampton stores monthly kWh consumption data by rate class and used this data to run these regressions. Based on the R square values that resulted from these regressions, Hydro One Brampton has determined that using the equation resulting from the individual rate class regression analysis is not satisfactory for forecasting purposes. The R square values resulting from the individual rate class regressions are shown in the following table.

Table 1: R Square Values for Individual Class Regression Analysis

Class	R Square Values
Residential	55.60%
Unmetered Scattered Load	68.15%
GS<50	60.03%
GS>50	42.25%
Intermediate	43.63%
Large User	63.55%
Street Lighting	73.78%

Hydro One Brampton believes that conducting a regression analysis that relates the monthly retail kWh of a class to other monthly variables is problematic. The amount billed to a customer within a month is not equal to the amount consumed within that month. The retail amount is based on billing cycle meter reading schedules. These reading dates vary throughout the month and do not normally take place at month end. The amount billed may include consumption data from the month before or perhaps even further back. Using a regression analysis to relate rate

class billing data to a variable like heating degree days does not appear to be reasonable as the resulting regression would be attempting to relate rate class billing data (like heating degree days) to billed data as opposed to consumption data. Hydro One Brampton believes that variables such as heating degree days impact the amount consumed not the amount billed.

Table 1 illustrates the inaccuracy of running the regression model on a per class basis. The accuracy of these regressions is expected to improve in future years once Smart Meters are fully deployed and all metered customer classes have meters equipped to provide hourly data. Once HOBNI is able to obtain hourly consumption data for all customers, this data would be used to prepare a more representative Load Forecast by customer class.

Hydro One Brampton understands that the development of a load forecast for the cost of service applications is an evolving process. Hydro One Brampton expects to include additional improvements to the load forecasting methodology in future cost of service rate applications by taking into consideration data provided by Smart Meters and Interval Meters as well as considering the methodologies employed by other electricity distributors. Based on the Board's approval of this methodology in a number of 2009 and 2010 applications, as well as the discussion that follows, Hydro One Brampton submits the load forecasting methodology is reasonable at this time for the purposes of this application.

The following tables provide a summary of the weather normalized customer/connection forecast used in this application:

- **Table 2: Summary of Weather Normalized Load Forecast**
- **Table 3: Retail Energy and Number of Customers / Connections by Rate Class**
- **Table 4: Annual Usage per Customer / Connection by Rate Class**

Table 2: Summary of Weather Normalized Load Forecast

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Weather	2011
Actual kWh Purchases	3,438,503,351	3,606,734,355	3,848,828,345	3,854,274,114	3,958,591,768	3,915,443,564	3,727,941,968		
Predicted kWh Purchase	3,454,916,499	3,546,950,265	3,848,828,345	3,833,699,583	3,988,592,061	3,915,428,135	3,759,311,464	3,821,797,458	3,898,527,442
Billed kWh	3,329,496,978	3,483,144,427	3,723,506,554	3,718,723,113	3,839,000,000	3,791,763,566	3,611,622,564	3,698,071,300	3,772,317,241
Residential									
Customers	91,671	98,355	104,822	109,778	114,119	119,060	121,041	122,377	123,660
kWh	918,500,653	933,248,820	1,066,310,557	1,041,609,067	1,102,238,845	1,093,569,512	1,088,557,819	1,099,386,751	1,107,769,581
GS<50									
Customers	6,512	6,648	6,892	7,075	7,294	7,437	7,529	7,728	7,893
kWh	261,424,109	264,116,354	288,084,106	282,703,766	298,781,693	288,052,193	278,899,780	285,620,803	290,725,436
USL									
Connections	1,105	1,130	1,159	1,207	1,250	1,267	1,280	1,287	1,300
kWh	7,522,732	5,817,642	5,528,171	5,294,847	5,047,284	5,109,078	5,104,985	5,013,040	4,899,876
GS>50									
Customers	1,357	1,393	1,364	1,402	1,417	1,491	1,554	1,544	1,552
kWh	996,032,849	1,045,707,603	1,083,191,856	1,080,817,874	1,109,791,374	1,116,951,693	1,081,007,720	1,097,553,564	1,123,789,074
kW	2,726,683	2,792,673	2,901,457	2,962,866	3,039,974	3,064,109	3,049,119	3,008,017	3,079,920
Intermediate									
Customers	126	124	121	119	117	116	114	110	106
kWh	845,121,401	922,964,134	954,061,083	950,418,593	942,048,351	872,587,042	788,185,444	816,592,994	832,077,628
kW	1,956,285	2,104,962	2,167,872	2,137,488	2,106,615	1,976,551	1,839,970	1,844,198	1,879,169
Large Use									
Customers	4	3	3	4	5	6	6	6	6
kWh	281,784,328	290,325,102	304,422,360	334,087,722	355,306,260	388,700,963	342,523,390	365,387,029	383,275,616
kW	531,189	505,001	515,785	589,471	639,861	712,935	696,851	664,899	697,451
SLR									
Customers	2	2	2	2	2	2	2	2	2
kWh	19,110,906	20,964,771	21,908,421	23,791,245	25,786,193	26,793,084	27,343,426	28,517,120	29,780,031
kW	58,415	60,474	65,522	70,150	76,385	79,929	81,921	84,878	88,637
Total									
Customer/Connections	100,777	107,656	114,361	119,587	124,204	129,379	131,525	133,054	134,519
kWh	3,329,496,978	3,483,144,427	3,723,506,554	3,718,723,113	3,839,000,000	3,791,763,566	3,611,622,564	3,698,071,300	3,772,317,241
kW from applicable classe	5,272,572	5,463,110	5,650,636	5,759,975	5,862,835	5,833,524	5,667,861	5,601,992	5,862,912

Table 3: Retail Energy and Number of Customers / Connections by Rate Class

Year	Residential	GS < 50	USL	GS> 50	Intermediate	Large User	SL	Total
Billed Energy (GWh)								
2003 Actual	918.50	261.42	7.52	996.03	845.12	281.78	19.11	**3329.50**
2004 Actual	933.24	264.12	5.81	1045.71	922.96	290.33	20.96	**3483.14**
2005 Actual	1066.30	288.08	5.53	1083.19	954.06	304.42	21.91	**3723.51**
2006 Actual	1041.60	282.70	5.29	1080.82	950.42	334.09	23.79	**3718.72**
2007 Actual	1102.20	298.78	5.05	1109.80	942.05	355.31	25.79	**3839.00**
2008 Actual	1093.60	288.05	5.11	1116.95	872.59	388.70	26.79	**3791.76**
2009 Actual	1088.60	278.90	5.10	1081.01	788.19	342.52	27.34	**3611.62**
2010 Normalized Bridge	1099.39	285.62	5.01	1097.55	816.59	365.39	28.52	**3698.07**
2011 Normalized Test	1107.77	290.73	4.90	1123.79	832.08	383.28	29.78	**3772.32**
Number of Customers / Connections								
2003 Actual	91,671	6,512	1,105	1,357	126	4	2	**100,777**
2004 Actual	98,355	6,648	1,130	1,393	124	3	2	**107,656**
2005 Actual	104,822	6,682	1,159	1,364	121	3	2	**114,361**
2006 Actual	109,778	7,075	1,207	1,402	119	4	2	**119,587**
2007 Actual	114,119	7,294	1,250	1,417	117	5	2	**124,204**
2008 Actual	119,060	7,437	1,267	1,491	116	6	2	**129,379**
2009 Actual	121,041	7,529	1,280	1,554	114	6	2	**131,525**
2010 Forecast	122,377	7,728	1,287	1,554	110	6	2	**133,054**
2011 Forecast	123,660	7,893	1,300	1,552	106	6	2	**134,519**

Table 4: Annual Usage per Customer / Connection by Rate Class

Year	Residential	GS < 50	USL	GS> 50	Intermediate	Large User	SL
Energy Usage per Customer / Connection by Rate Class							
2003 Actual	10,020	40,147	6,808	733,771	6,711,752	70,446,082	9,555,453
2004 Actual	9,489	39,727	5,148	750,508	7,423,304	94,159,492	10,482,386
2005 Actual	10,173	41,802	4,770	794,275	7,917,519	101,474,120	10,954,211
2006 Actual	9,488	39,956	4,387	770,866	8,009,145	85,298,993	11,895,622
2007 Actual	9,659	40,961	4,038	783,290	8,063,181	72,265,680	12,893,097
2008 Actual	9,185	38,734	4,032	749,046	7,543,980	64,783,494	13,396,542
2009 Actual	8,993	37,045	3,988	695,778	6,918,965	57,087,232	13,671,713
2010 Normalized Bridge	**8,833**	**36,551**	**3,648**	**689,640**	**6,954,117**	**55,121,286**	**14,512,811**
2011 Normalized Test	**8,675**	**36,065**	**3,337**	**683,557**	**6,989,448**	**53,223,042**	**15,405,654**
Annual growth Rate in Usage per Customer / Connection							
2004 Actual	0.9470	0.9896	0.7562	1.0228	1.1060	1.3366	0.0970
2005 Actual	1.0721	1.0522	0.9265	1.0583	1.0666	1.0777	1.0450
2006 Actual	0.9327	0.9558	0.9197	0.9705	1.0116	0.8406	1.0859
2007 Actual	1.0180	1.0251	0.9205	1.0161	1.0067	0.8472	1.0839
2008 Actual0	0.9510	0.9456	0.9987	0.9563	0.9356	0.8965	0.0390
2009 Actual	0.9791	0.9564	0.9891	0.9289	0.9172	0.8812	1.0205
2010 Normalized Bridge	**0.9822**	**0.9867**	**0.9147**	**0.9912**	**1.0051**	**0.9656**	**1.0615**
2011 Normalized Test	**0.9822**	**0.9867**	**0.9147**	**0.9912**	**1.0051**	**0.9656**	**1.0615**

LOAD FORECASTING ASSUMPTIONS AND EXPLANATIONS

In order to use the multifactor regression model to determine the load forecast, a variety of assumptions must be made regarding the inputs for the Bridge and Test Years. Some inputs for these years, such as the number of days in the month and the spring/fall flag, are known and can be entered directly into the model. Other inputs, such as Ontario GDP and Heating Degree Days must be estimated for the Bridge and Test Year to complete the forecast. The following will outline the assumptions used, how these assumptions were made, and which areas they impact within the model.

CUSTOMER GROWTH

Customer counts are utilized in a variety of places within the multifactor regression model. While Hydro One Brampton has used population to determine the monthly predicted purchases, customer growth is an important component in allocating the Bridge and Test Year predicted kWh and KW across rate classes. Hydro One Brampton has estimated their customer growth for the Bridge and Test Year by exponentially smoothing the historical customer counts from 2003 to 2009 and using the smoothed growth up to 2009 to determine the customer forecast for 2010 and 2011.

Exponential smoothing works similarly to a weighted average by applying exponentially increasing weights to more recent data. Hydro One Brampton has historically seen high levels of customer growth; however, the rate of growth has shown to be decreasing in more recent years. Using exponential smoothing to forecast growth for the base and Test Years incorporates both the historically high customer growth rates and the more recent decline in growth rates.

POPULATION GROWTH

Population data is used both to run the regression model and to predict the purchased kWh values for the Bridge and Test Years. Historical and forecast data for the population of Brampton has been provided by the economics department of the City of Brampton.

AVERAGE USE PER CUSTOMER

The average use per customer is used within the Rate Class Energy Model to allocate the predicted retail kWh to each rate class. The historical average use per customer is applied to the customer forecast for the Base and Test Years to determine the Customer Class Average Consumption Forecast.

The average use per customer is determined by dividing the allocated retail kWh's by the number of customers in that rate class for the years 2003 through 2009. The geometric mean of this historical data is calculated and is applied to the Base and Test Years.

CONSUMPTION ADJUSTMENT

Once the Customer Class Average Consumption Forecast is determined the difference between this forecast and the total predicted Retail kWh's is calculated. This difference is referred to as the Consumption Adjustment and must be allocated across each rate class. Weighting factors for each rate class are used to allocate this adjustment.

The weighting factors used to allocate the consumption adjustment to each rate class are calculated based on the proportionate per rate class usage per rate class from 2007. Hydro One Brampton has elected to use 2007 usage patterns to allocate this adjustment as the total predicted purchases for the 2011 Test Year most closely reflect total purchased kWh from 2007.

First the ratio of total use for each customer class for 2007 is determined and applied to the Consumption Adjustment, and then minor adjustments were made to reflect changes in Hydro One Brampton's customer base since 2007.

After applying these adjustments, consumption for each rate class is determined and used in the Load Forecast.

ONTARIO GDP

Ontario GDP is one of the largest drivers in the regression model. The predicted retail kWhs have proven to be sensitive to the GDP forecast with small increases in the GDP causing large increased in the predicted kWhs.

Historical GDP values are taken from Statistics Canada. Quarterly values are used to reflect the impact of shifts in the GDP throughout the year. For the Bridge and Test Years the forecast GDP growth for 2010 and 2011 is used as published by the Ministry of Finance.

HEATING DEGREE DAYS AND COOLING DEGREE DAYS

Heating Degree Days and Cooling Degree Days are used to run the regression to determine the predicted kWh. In order to forecast for the Bridge and Test Years the 30 year average is calculated for both heating degree days and cooling degree days. This average is applied to the Bridge and Test Year to forecast the weather normalized kWh's purchased.

CONSERVATION AND DEMAND MANAGEMENT

Hydro One Brampton supports the Ontario Government's conservation and demand management (CDM) initiative and will work with the OPA to meet the new provincial CDM target. The CDM impact assumed for 2011 (64 GWh) was based on Hydro One Brampton's share (2.75%) of the provincial CDM impact assumed for 2011 (2,386 GWh) adjusted for transmission losses (2.5%). The annual CDM impact for 2010-2012 submitted in the IPSP by the OPA to the Ontario Energy Board in August 2007 was adjusted to account for the recent economic recession and its impact on industrial customers and the new CDM target for LDCs for the 2011-2014 period. **Table 1** summarizes the adjusted annual provincial CDM impact assumed by Hydro One Brampton for 2008-2012.

Table 1: Provincial CDM Impact (in GWh)

Provincial CDM Impact (in GWh)

	Provincial CDM Impact Assumed in 2007 IPSP		Provincial CDM Impact Assumed in this Rate Case	
	Incremental	Cumulative since 2008	Incremental	Cumulative since 2008
2008	814	814	814	814
2009	1,146	1,960	1,146	1,960
2010	4,908	6,868	3,416	5,376
2011	1,885	8,753	2,386	7,762
2012	1,909	10,662	2,900	10,662

Note 1: CDM impact is presented at generation station level, weather normal

Note 2: Cumulative CDM impact of 10,662 GWh remains the same by 2012

The CDM impact of 64 GWh assumed for Hydro One Brampton in 2011 is derived as follows:

- 2,386 GWh * (1 – 2.5%) * 2.75% where
- 2,386 GWh is the annual provincial CDM impact for 2011.
- (1 – 2.5%) brings the CDM impact from generation station to wholesale purchase level. Transmission losses are assumed to be 2.5%.
- 2.75% is Hydro One Brampton's share of the provincial energy estimated by the IESO.

LOAD FORECASTING METHODOLOGY

Hydro One Brampton's weather normalized load forecast is developed in a three step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model. This model incorporates historical load, weather, and economic data. Once this forecast is developed, the OPA forecast of CDM savings for 2011 proportioned to Hydro One Brampton are backed out. Second, the weather normalized purchases energy forecast is adjusted by a historical loss factor to produce a weather normalized retail energy forecast. Lastly, the forecast of retail energy by rate class is determined based on a forecast of customer numbers and historical customer usage patterns. The forecast of customers by rate class is determined using exponentially smoothed historical data. For classes that use kW as the distribution volumetric billing determinant, the kW demand values are forecast based on the historical average customer class specific ratios of kW to kWh.

The forecasted retail energy per class is adjusted based on a consumption adjustment factor. This process determines the difference between the retail energy forecast and the amount of that forecast that is allocated to a customer class based on historical customer usage patterns and the forecast of customer numbers. This difference is then allocated to each rate class using a factor that best relates predicted kWh growth per class to historical kWh growth per class.

PURCHASED kWh LOAD FORECAST

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables:

- weather (heating and cooling degree days),
- economy (indexed Ontario GDP growth),
- population (City of Brampton),
- calendar variables (number of days in the month, season flags), and
- situational (August 2003 blackout flag).

The regression model uses monthly kWh and monthly values of independent variables from January 2003 to December 2009 to determine the monthly regression coefficients.

Complete data for Hydro One Brampton's total system load is available as far back as January of 2003. This provides 84 monthly data points which make up a reasonable data set for use in a multifactor regression analysis.

The multifactor regression model has determined drivers of year over year changes in Hydro One Brampton's load growth are: economic growth, weather and calendar factors, and population growth. These factors are all captured within the regression model.

Economic growth includes customer trends in the Hydro One Brampton service area as well as general economic conditions. The general economic conditions of the Province are captured using an index of Ontario Real Gross Domestic Product (GDP). Customer trends are captured within the month over month kWh historical data.

The impact of weather on loads can be seen in both the winter heating season and the summer cooling season. To incorporate this impact both Heating Degree Days (i.e. a measure of coldness in the winter) and Cooling Degree Days (i.e. a measure of heat in the summer) are modeled.

Another main set of factors in determining the predicted kWh are classified as "calendar factors". For example, the number of days in a month will impact the total energy usage. The modeling of purchase energy uses the number of days in the month as well as a flag variable to capture typically lower usage in the spring and fall months.

Finally, population growth has a large impact on energy usage. The growth rates of population in the City of Brampton were historically quite high; however, the rate of growth has diminished over the past few years. The model captures the impact of the diminishing growth rates in Brampton's population on total purchased energy.

The following table outlines the prediction model used by Hydro One Brampton to predict weather normalized energy purchases for 2010 and 2011.

Table 1: CAP: Hydro One Brampton Monthly Predicted kWh Purchases

	Regression Variable		Coefficient
	Constant	×	-393,051,501.00
+	Heating Degree Days	×	49,250.10
+	Cooling Degree Days	×	417,362.92
+	Ontario Real GDP Monthly	×	351,562,161.20
+	Number of Days in Month	×	7,933,174.94
+	Spring Fall Flag	×	-12,325,306.36
+	Blackout Flag	×	-22,355,282.21
+	Population	×	20.55
+	Number of Peak Hours	×	167,629.73
=	**Monthly Predicted kWh Purchases**		

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Exhibit 3 Tab 2 Schedule 3.1.

The sources of data for the various data points are as follows:

- Environment Canada website for monthly heating degree day and cooling degree day information.
- Statistics Canada CANSIM v3839818 Ontario; Gross domestic product, chained (2002) dollars were used for historical GDP indexing.
- The Ministry of Finance Provincial Outlook published in March of 2010 was used for the future looking GDP growth rates.
- Calendar information provided information relating to the number of days in the month and the spring/fall flag.
- Number of peak hours was calculated at 16 hours per day for normal weekdays (i.e. no weekends or holidays) as indicated by the calendar and by the IESO weekly market report located here
- Historic and forecast population data for the city of Brampton was taken from the City of Brampton's planning report as published in April of 2009.
- Customer data is based on historical customer data and the customer forecast discussed later in this application.

The prediction formula yielded the following statistical results which generally indicate the formula was a good fit to the actual data set.

Table 2: Statistical Results

Statistic	Value
R Square	0.95
Adjusted R Square	0.95
F Test	243.73
T-Stats by Coefficient	
Intercept	(11.52)
Heating Degree Days	11.92
Cooling Degree Days	16.76
Ontario Real GDP Monthly %	12.39
Number of Days in Month	9.42
Spring Fall Flag	(6.61)
Blackout Flag	(3.40)
Population	0.62
Number of Peak Hours	4.12

The annual results of the above prediction formula compared to the actual annual purchases in kWh from 2003 to 2009 are illustrated in the chart below:

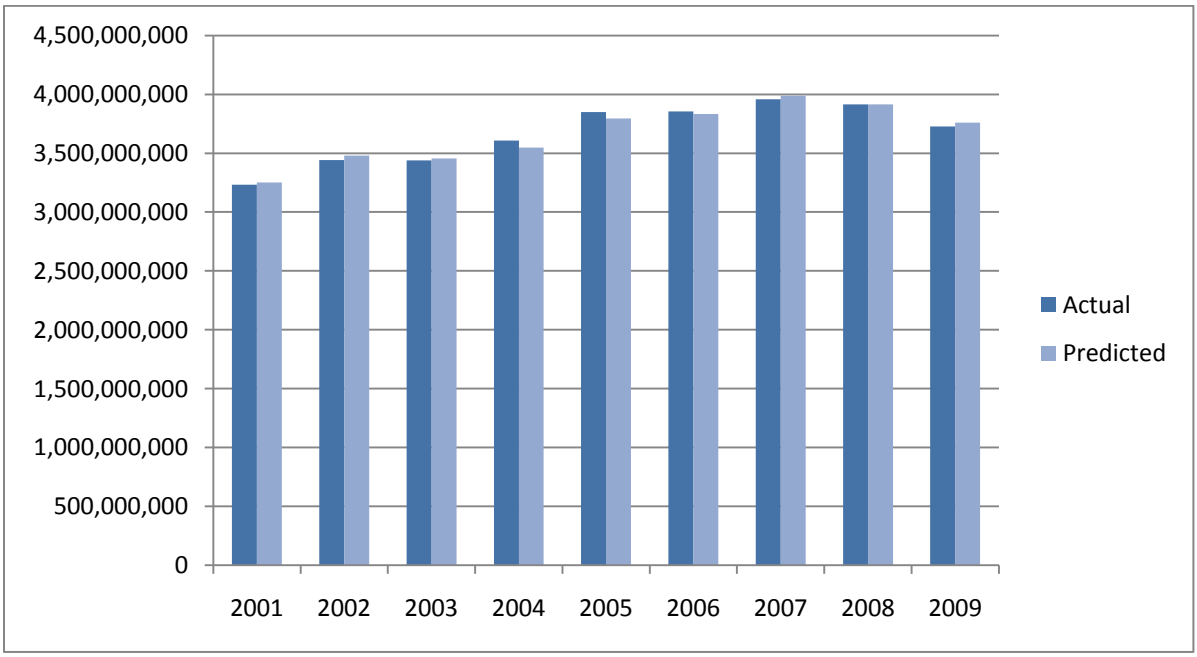


Figure 1: Prediction vs. Actual Purchases (kWh) 2003 - 2009

The following table outlines the data that supports the above chart. In addition, the predicted total systems purchases for Hydro One Brampton are provided for 2010 and 2011.

Table 3: Hydro One Brampton Monthly kWh Purchases

Year	Actual	Predicted	% Difference
2001	3,232,193,978	**3,252,396,515**	0.63%
2002	3,441,504,117	**3,478,598,925**	1.08%
2003	3,438,503,351	**3,478,598,925**	0.48%
2004	3,606,734,355	**3,546,950,265**	-1.66%
2005	3,848,828,345	**3,794,122,112**	-1.42%
2006	3,854,274,114	**3,833,699,583**	-0.53%
2007	3,958,591,768	**3,988,592,061**	0.76%
2008	3,915,443,564	**3,915,428,135**	0.00%
2009	3,727,941,968	**3,759,311,464**	0.84%
2010		**3,821,797,458**	
2011		**3,898,527,442**	

The weather normalized quantities for the Bridge and Test Years is determined by using 2010 and 2011 independent variables in the prediction formula on a monthly basis along with the average monthly heating degree days and cooling degree days which has occurred from January 2003 to December 2009.

The 2011 predicted values have been used as the purchased forecast in this application for the purpose of determining a retail kWh load forecast which is used to design rates.

RETAIL kWh FORECAST

To determine the total normalized energy retail forecast, the total system weather normalized purchase forecast is adjusted by the historical loss factor. As outlined below, the historical loss factor for Hydro One Brampton has been:

Table 4: Historical Loss Factor

Year	Actual Purchased	Actual Billed	Loss Factor
2003	3,438,503,351	**3,454,916,499**	1.0327
2004	3,606,734,355	**3,546,950,265**	1.0355
2005	3,848,828,345	**3,794,122,112**	1.0337
2006	3,854,274,114	**3,833,699,583**	1.0365
2007	3,958,591,768	**3,988,592,061**	1.0312
2008	3,915,443,564	**3,915,428,135**	1.0326
2009	3,727,941,968	**3,759,311,464**	1.0322
Average			**1.0334**

With this average loss factor the total weather normalized metered retail energy will be 3,698,071,300 kWh for 2010 and 3,772,317,241 kWh for 2011.

RETAIL kWh LOAD FORECAST AND CUSTOMER / CONNECTION FORECAST BY RATE CLASS

The total weather normalized retail energy forecast needs to be distributed by rate class for rate design purposes. This distribution of energy consumption by rate class needs to take into consideration the customer/connection forecast and the expected usage per customer by rate class.

After determining the total retail energy amount, the next step in the forecasting process is to determine the customer/connection forecast. The customer/connection forecast is based on historical customer/connection data as shown in the **Table 5** on the following page.

Table 5: Historical Customer / Connection Data

Year	Residential	USL	GS < 50	GS > 50	Intermediate	Large User	SL
2003	91,671	6,512	1,105	1,357	126	4	2
2004	98,355	6,648	1,130	1,393	124	3	2
2005	104,822	6,892	1,159	1,364	121	3	2
2006	109,778	7,075	1,207	1,402	119	4	2
2007	114,119	7,294	1,250	1,417	117	5	2
2008	119,060	7,437	1,267	1,491	116	6	2
2009	121,041	7,529	1,280	1,554	114	6	2

Next the historical customer/connection forecast is exponentially smoothed for use in forecasting the Base and Test Year customer/connection data. Exponential smoothing is a technique that can be applied to time series data for forecasting purposes. This method works similarly to a moving weighted average; however, instead of giving equal weighting to all data, each observation is assigned an exponentially decreasing weight over time. This methodology allows for the customer/connection forecast to be based on data that considers the diminishing customer growth rate witnessed across Hydro One Brampton's customer counts. The annualized exponentially smoothed customer/connection data is provided in the table below. Since Large User and Street Lighting Customer counts are expected to stay the same for the Bridge and Test Years, their customer data has not been exponentially smoothed.

Table 6: Exponentially Smoothed Customer / Connection Data

Year	Residential	USL	GS < 50	GS > 50	Intermediate
2003	91,178	6,504	1,352	1,105	125
2004	97,502	6,621	1,395	1,127	126
2005	104,150	6,868	1,365	1,156	121
2006	109,292	7,055	1,397	1,201	119
2007	113,492	7,262	1,413	1,245	117
2008	118,639	7,430	1,482	1,265	115
2009	120,998	7,530	1,549	1,278	114

In order to grow the customer/connection counts to create a forecast for 2010 and 2011 Hydro One Brampton has applied the average growth rate for the exponentially smoothed 2009 data. The growth rate of the exponentially smoothed data incorporates the impact of both historically high customer growths at the beginning of the millennium as well as the diminishing growth rates that have been witnessed over the past few years. The growth rates associated with the exponentially smoothed historic customer/connection data is illustrated on an annual basis in the table below.

Table 7: Growth Rates of Exponentially Smoothed Customer / Connection Data

Year	Residential	USL	GS < 50	GS > 50	Intermediate
2004	1.069	1.018	1.032	1.02	1.005
2005	1.068	1.037	0.978	1.025	0.962
2006	1.049	1.027	1.023	1.04	0.981
2007	1.038	1.029	1.012	1.036	0.991
2008	1.045	1.023	1.048	1.016	0.981
2009	1.02	1.013	1.046	1.011	0.99

Table 8 (below) outlines the forecast of customers by rate class for 2010 and 2011 using the growth rates of the exponentially smoothed data for 2009.

Table 8: Customer / Connection Forecast

Year	Residential	USL	GS < 50	GS > 50	Intermediate	Large User	SL
2010	122,377	1,287	7,728	1,544	110	6	2
2011	123,660	1,300	7,893	1,552	106	6	2

As seen above, the Street Lighting and Large Use classes have not been grown for the 2010 Bridge and 2011 Test Years. The number of Street Lighting customers has remained stagnant at two customers dating even further back than 2003. Hydro One Brampton has no reason to believe that any customers will be added to this class and as such has kept Street Lighting at two customers for 2010 and 2011. Hydro One Brampton has seen very little fluctuation in the Large Use class over the past six years. Hydro One Brampton has no reason to believe that they will be gaining or losing any of their Large Use customers and as such has elected to hold the customer count steady for 2010 and 2011.

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. **Table** 9 below provides the average annual usage per customer by rate class from 2003 through 2009.

Table 9: Historical Annual Usage per Customer

Year	Residential	USL	GS < 50	GS > 50	Intermediate	Large User	SL
2003	10,020	6,808	40,147	733,771	6,711,752	70,446,082	9,555,453
2004	9,489	5,148	39,727	750,508	7,423,304	94,159,492	10,482,386
2005	10,173	4,770	41,802	794,275	7,917,519	101,474,120	10,954,211
2006	9,488	4,387	39,956	770,866	8,009,145	85,298,993	11,895,622
2007	9,659	4,038	40,961	783,290	8,063,181	71,265,680	12,893,097
2008	9,185	4,032	38,734	749,046	7,543,980	64,783,494	13,396,542
2009	8,993	3,988	37,045	695,778	6,918,965	57,087,232	13,671,713

As can be seen from the above table, the average use per customer has been on the decline since 2005. Hydro One Brampton believes that this decline can be attributed to the CDM programs initiated in 2005 as well as with cooler summer weather from 2008 and 2009.

The growth rates in the average use per customer are provided in the following table. The geometric mean is also provided as it is used to determine the usage per customer/connection for the Bridge and Test Years.

Table 10: Growth Rate in Usage per Customer / Connection

Year	Residential	USL	GS < 50	GS > 50	Intermediate	Large User	SL
2004	0.9470	**0.7562**	0.0896	1.0228	1.1060	1.3366	1.0970
2005	1.0721	**0.9265**	1.0522	1.0583	1.0666	1.0777	1.0450
2006	0.9327	**0.9197**	0.9558	0.9705	1.0116	0.8406	1.0859
2007	1.0280	**0.9205**	1.0251	1.0161	1.0067	0.8472	1.0839
2008	0.9510	**0.9987**	0.9456	0.9563	0.9356	0.8965	1.0390
2009	0.9791	**0.9891**	0.9564	0.9289	0.9172	0.8812	1.0205
Geometric Mean	**0.98227**	**0.9147**	**0.9867**	**0.9912**	**1.0051**	**0.9856**	**1.0615**

Using the geometric mean to continue the growth trend of the average use per customer/connection onward Hydro One Brampton yields the following average use for 2010 and 2011.

Table 11: Forecast Annual kWh Usage per Customer / Connection

Year	Residential	USL	GS < 50	GS > 50	Intermediate	Large User	SL
2010	8,833	3,648	36,551	689,640	6,954,117	55,121,286	14,512,811
2011	8,675	3,337	36,065	683,557	6,989,448	53,223,042	15,405,654

Using the information from **Table 11,** the non-normalized retail energy forecast can be determined by multiplying the forecast number of customers/connections from **Table 8** by the forecast of annual usage per customer/connection from **Table 11**. The resulting non-weather normalized retail energy forecast is shown below in **Table 12**.

Table 12: Unadjusted Retail Energy Forecast

Residential	USL	GS < 50	GS > 50	Intermediate	Large User	SL	Total
1,080,927,480	4,695,742	282,469,635	1,064,591,727	766,979,427	330,727,715	29,025,622	3,559,417,348
1,072,768,740	4,339,638	284,658,377	1,061,025,381	740,555,007	319,338,254	30,811,309	3,513,496,706

The unadjusted retail energy forecast has been determined, however, this needs to be adjusted in order to be aligned with the total weather normalized energy forecast. As previously determined, the total weather normalized retail energy forecast is 3,698,071,300 kWh for 2010 and 3,772,317,241 kWh for 2011.

The difference between the unadjusted retail energy forecast and the total retail energy forecast is 138,653,952 kWh for 2010 and 258,820,535 kWh for 2011. Hydro One Brampton is of the view that the difference between the two forecasts relates to the inability of the average use per customer forecast to include the future impact of additional Provincial CDM initiatives. The total retail energy forecast using the multiple regression technique is much more sophisticated than the geometric mean approach used to forecast the usage per rate class for 2010 and 2011. Hydro One Brampton believes that the unadjusted retail energy forecast provides a reasonable approach to assigning retail consumption by customer class; however, further allocations are necessary so that all of the aggregate retail energy forecasted consumption is accounted for.

Hydro One Brampton has allocated the difference between the two forecasts across the rate classes using the following weighting factors to allocate this adjustment for the 2010 Base and 2011 Test Year.

Table 13: Consumption Adjustment Weighting Factors

Residential	USL	GS < 50	GS > 50	Intermediate	Large User	SL
7.266	28.750	4.747	13.174	27.523	44.589	-7.454

These sensitivity factors were determined to allocate the total kWh retail energy forecast across each rate class in a similar weighting to those seen in 2007. This methodology was chosen as the total retail kWh forecast for 2011 is almost on par with the actual retail kWh from 2007.

In addition to allocating the unadjusted retail kWh forecast to each rate class based on 2007 allocations, a few adjustments were made to determine sensitivity factors that reflected changes in Hydro One Brampton's customer base.

These adjustments, as well as the 2007 retail kWh allocation per rate class were considered when determining the sensitivity factors that allocate the consumption adjustment across each rate class.

The consumption adjustment has been allocated to each rate class weighted on the factors provided in **Table 13**. The following table outlines how each class has been affected by this adjustment.

Table 14: Alignment of Unadjusted to Total Retail Forecast

Year	Residential	USL	GS < 50	GS > 50	Intermediate	Large User	SL	Total
Unadjusted Forecast								
2010	1,080,927,480	4,695,742	282,469,635	1,064,591,727	766,979,427	330,727,715	29,025,622	**3,559,417,348**
2011	1,072,768,740	4,339,638	284,658,377	1,061,025,381	740,555,007	319,338,254	30,811,309	**3,513,496,706**
Consumption Adjustment								
2010	18,459,270	317,299	3,151,168	32,961,837	49,613,566	34,659,314	-508,502	**138,653,953**
2011	35,000,841	560,238	6,067,059	62,763,693	91,522,621	63,937,362	-1,031,278	**258,820,535**
Adjusted Forecast								
2010	1,099,386,751	5,013,040	285,620,803	1,097,553,564	816,592,994	365,387,029	28,517,120	**3,698,071,300**
2011	1,107,769,581	4,899,876	290,725,436	1,123,789,074	832,077,628	383,275,616	29,780,031	**3,772,317,241**

LOAD FORECASTING MODEL

Table 1: Load Forecasting Model

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Blackout Flag	Population	Number of Peak Hours	Predicted Purchases	Variances (kWh)	% Variance
Jan-01	280,845,210	684.9	0.0	86.22%	31	0	0	329,000	352	255,498,054	(25,347,156)	-9.03%
Feb-01	255,669,091	587.5	0.0	96.53%	28	0	0	330,000	320	257,786,383	2,117,292	0.83%
Mar-01	270,976,956	566.6	0.0	97.18%	31	1	0	331,000	352	275,909,075	4,932,119	1.82%
Apr-01	241,625,477	293.8	1.4	97.46%	30	1	0	332,000	320	250,774,759	9,149,282	3.79%
May-01	254,877,802	111.5	12.2	97.15%	31	1	0	333,000	352	258,540,036	3,662,234	1.44%
Jun-01	280,369,159	30.2	79.7	96.59%	30	0	0	334,000	336	282,441,160	2,072,001	0.74%
Jul-01	283,380,117	9.3	100.9	95.26%	31	0	0	335,000	336	293,565,688	10,185,571	3.59%
Aug-01	309,700,654	0.0	160.0	96.49%	31	0	0	336,000	352	324,775,811	15,075,157	4.87%
Sep-01	256,033,996	73.6	35.7	98.54%	30	1	0	337,000	304	255,466,872	(567,124)	-0.22%
Oct-01	262,356,881	232.5	2.0	97.55%	31	1	0	338,000	352	261,745,240	(611,640)	-0.23%
Nov-01	263,952,616	324.5	0.0	98.53%	30	1	0	339,000	352	260,959,721	(2,992,894)	-1.13%
Dec-01	272,406,020	505.0	0.0	96.49%	31	0	0	340,000	304	274,933,717	2,527,697	0.93%
Jan-02	284,761,887	572.2	0.0	97.92%	31	0	0	341,333	352	291,330,437	6,568,550	2.31%
Feb-02	261,561,491	540.2	0.0	99.08%	28	0	0	342,667	320	264,710,140	3,148,648	1.20%
Mar-02	281,058,428	545.6	0.0	99.75%	31	1	0	344,000	320	278,831,115	(2,227,313)	-0.79%
Apr-02	267,232,388	329.5	8.3	99.68%	30	1	0	345,333	352	268,834,137	1,601,749	0.60%
May-02	268,731,435	227.5	7.8	99.36%	31	1	0	346,667	352	270,455,691	1,724,256	0.64%
Jun-02	287,224,946	36.2	70.0	98.78%	30	0	0	348,000	320	284,007,195	(3,217,751)	-1.12%
Jul-02	336,393,633	0.0	192.4	98.96%	31	0	0	349,333	352	347,263,094	10,869,460	3.23%
Aug-02	323,078,534	0.2	142.7	100.23%	31	0	0	350,667	336	328,341,651	5,263,117	1.63%
Sep-02	288,951,649	21.8	87.6	102.36%	30	1	0	352,000	320	291,004,426	2,052,777	0.71%
Oct-02	274,918,581	292.2	10.0	101.10%	31	1	0	353,333	352	280,799,327	5,880,746	2.14%
Nov-02	278,120,054	445.0	0.0	102.11%	30	1	0	354,667	336	277,118,375	(1,001,679)	-0.36%
Dec-02	289,471,090	619.4	0.0	100.00%	31	0	0	356,000	320	295,903,338	6,432,248	2.22%
Jan-03	307,542,957	814.6	0.0	100.73%	31	0	0	357,333	352	313,467,104	5,924,148	1.93%
Feb-03	279,902,418	699.0	0.0	101.92%	28	0	0	358,667	320	282,846,433	2,944,015	1.05%
Mar-03	292,786,171	581.1	0.0	102.61%	31	1	0	360,000	336	293,645,341	859,170	0.29%
Apr-03	269,814,265	372.5	2.4	101.84%	30	1	0	361,333	336	273,752,434	3,938,170	1.46%
May-03	267,913,712	177.8	0.0	101.52%	31	1	0	362,667	336	269,991,245	2,077,533	0.78%
Jun-03	286,282,449	43.4	52.9	100.93%	30	0	0	364,000	336	287,783,630	1,501,180	0.52%
Jul-03	318,440,802	0.2	118.3	99.01%	31	0	0	365,333	352	316,858,340	(1,582,462)	-0.50%
Aug-03	297,771,903	2.0	128.0	100.28%	31	0	1	366,667	320	297,771,903	0	0.00%
Sep-03	267,335,938	54.9	24.0	102.42%	30	1	0	368,000	336	269,291,005	1,955,068	0.73%
Oct-03	274,153,307	275.8	0.0	101.55%	31	1	0	369,333	352	277,755,263	3,601,955	1.31%
Nov-03	281,313,885	398.5	0.0	102.57%	30	1	0	370,667	320	274,099,616	(7,214,268)	-2.56%
Dec-03	295,245,545	561.5	0.0	100.45%	31	0	0	372,000	336	297,654,185	2,408,640	0.82%
Jan-04	318,825,772	849.1	0.0	100.73%	31	0	0	373,417	336	312,837,532	(5,988,240)	-1.88%
Feb-04	292,561,276	631.7	0.0	101.93%	29	0	0	374,833	320	287,820,164	(4,741,112)	-1.62%
Mar-04	304,403,356	487.3	0.0	102.62%	31	1	0	376,250	368	294,746,634	(9,656,722)	-3.17%
Apr-04	280,729,504	331.5	0.0	103.71%	30	1	0	377,667	336	277,619,242	(3,110,262)	-1.11%
May-04	284,754,157	158.9	8.6	103.38%	31	1	0	379,083	320	276,836,516	(7,917,641)	-2.78%
Jun-04	296,130,055	44.2	31.6	102.77%	30	0	0	380,500	352	288,447,598	(7,682,456)	-2.59%
Jul-04	316,526,152	3.6	85.4	103.20%	31	0	0	381,917	336	315,687,828	(838,323)	-0.26%
Aug-04	311,532,144	12.8	59.6	104.53%	31	0	0	383,333	336	310,060,348	(1,471,796)	-0.47%
Sep-04	300,510,639	30.0	41.2	106.75%	30	1	0	384,750	336	290,829,552	(9,681,087)	-3.22%
Oct-04	288,181,524	226.3	1.5	105.36%	31	1	0	386,167	320	284,324,948	(3,856,576)	-1.34%
Nov-04	296,760,230	380.3	0.0	106.42%	30	1	0	387,583	352	292,448,651	(4,311,579)	-1.45%
Dec-04	315,819,546	643.4	0.0	104.22%	31	0	0	389,000	336	315,291,250	(528,296)	-0.17%

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	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Blackout Flag	Population	Number of Peak Hours	Predicted Purchases	Variances (kWh)	% Variance
Jan-05	329,967,591	770.0	0.0	104.73%	31	0	0	391,000	320	320,662,164	(9,305,427)	-2.82%
Feb-05	293,588,958	616.4	0.0	105.97%	28	0	0	393,000	320	293,714,787	125,829	0.04%
Mar-05	313,508,514	608.6	0.0	106.69%	31	1	0	395,000	352	312,728,253	(780,261)	-0.25%
Apr-05	285,449,756	306.8	0.0	106.72%	30	1	0	397,000	336	287,411,776	1,962,020	0.68%
May-05	287,810,113	189.4	0.8	106.39%	31	1	0	399,000	336	288,753,197	943,084	0.33%
Jun-05	354,566,496	8.9	146.3	105.76%	30	0	0	401,000	352	345,518,717	(9,047,779)	-2.55%
Jul-05	365,920,796	0.0	188.7	105.42%	31	0	0	403,000	320	364,165,884	(1,754,913)	-0.48%
Aug-05	358,835,199	0.2	140.7	106.77%	31	0	0	405,000	352	354,305,121	(4,530,078)	-1.26%
Sep-05	314,383,694	22.6	50.6	109.05%	30	1	0	407,000	336	302,903,833	(11,479,860)	-3.65%
Oct-05	304,341,532	220.2	8.0	108.14%	31	1	0	409,000	320	296,956,400	(7,385,132)	-2.43%
Nov-05	311,009,155	388.4	0.0	109.22%	30	1	0	411,000	352	303,176,398	(7,832,757)	-2.52%
Dec-05	329,446,542	665.3	0.0	106.97%	31	0	0	413,000	320	323,825,582	(5,620,961)	-1.71%
Jan-06	329,248,077	551.8	0.0	107.97%	31	0	0	414,667	336	324,489,484	(4,758,593)	-1.45%
Feb-06	304,825,405	604.2	0.0	109.26%	28	0	0	416,333	320	305,134,022	308,618	0.10%
Mar-06	325,241,932	516.6	0.0	109.99%	31	1	0	418,000	368	322,970,511	(2,271,421)	-0.70%
Apr-06	289,070,045	293.3	0.0	109.98%	30	1	0	419,667	304	293,312,647	4,242,602	1.47%
May-06	310,032,606	136.9	26.0	109.64%	31	1	0	421,333	352	311,254,198	1,221,592	0.39%
Jun-06	333,895,801	19.5	72.6	109.00%	30	0	0	423,000	352	327,094,355	(6,801,446)	-2.04%
Jul-06	371,225,703	0.0	167.3	107.81%	31	0	0	424,667	320	364,101,890	(7,123,813)	-1.92%
Aug-06	353,706,210	4.2	101.5	109.20%	31	0	0	426,333	352	347,111,061	(6,595,149)	-1.86%
Sep-06	298,103,405	80.9	12.9	111.52%	30	1	0	428,000	320	296,502,089	(1,601,315)	-0.54%
Oct-06	307,942,171	288.3	1.1	110.46%	31	1	0	429,667	336	308,697,806	755,635	0.25%
Nov-06	312,999,806	382.0	0.0	111.56%	30	1	0	431,333	352	311,521,183	(1,478,623)	-0.47%
Dec-06	317,982,954	500.5	0.0	109.26%	31	0	0	433,000	304	321,510,337	3,527,383	1.11%
Jan-07	332,533,628	649.6	0.0	110.25%	31	0	0	434,417	352	340,408,965	7,875,337	2.37%
Feb-07	318,174,492	740.1	0.0	111.56%	28	0	0	435,833	320	320,338,325	2,163,832	0.68%
Mar-07	330,329,411	546.7	0.0	112.32%	31	1	0	437,250	352	330,330,625	1,214	0.00%
Apr-07	301,193,988	356.4	0.0	112.73%	30	1	0	438,667	320	309,156,585	7,962,597	2.64%
May-07	313,881,665	136.4	22.4	112.38%	31	1	0	440,083	352	319,745,221	5,863,556	1.87%
Jun-07	352,305,947	16.5	99.2	111.72%	30	0	0	441,500	336	345,322,770	(6,983,177)	-1.98%
Jul-07	350,987,926	3.2	106.1	110.77%	31	0	0	442,917	336	352,165,805	1,177,878	0.34%
Aug-07	363,680,291	5.2	141.0	112.19%	31	0	0	444,333	352	374,540,237	10,859,946	2.99%
Sep-07	320,412,436	36.7	47.5	114.58%	30	1	0	445,750	304	317,197,911	(3,214,524)	-1.00%
Oct-07	318,245,128	137.6	19.8	112.66%	31	1	0	447,167	352	319,841,430	1,596,302	0.50%
Nov-07	323,515,779	462.5	0.0	113.78%	30	1	0	448,583	352	323,636,751	120,972	0.04%
Dec-07	333,331,077	630.7	0.0	111.43%	31	0	0	450,000	304	335,907,435	2,576,359	0.77%
Jan-08	344,575,662	626.0	0.0	110.91%	31	0	0	451,250	352	341,918,110	(2,657,553)	-0.77%
Feb-08	326,113,372	674.7	0.0	112.23%	29	0	0	452,500	320	327,746,511	1,633,140	0.50%
Mar-08	331,077,485	610.2	0.0	112.99%	31	1	0	453,750	304	328,120,502	(2,956,983)	-0.89%
Apr-08	303,230,329	253.9	0.0	112.66%	30	1	0	455,000	352	309,541,353	6,311,023	2.08%
May-08	301,056,523	193.5	2.5	112.30%	31	1	0	456,250	336	311,635,865	10,579,342	3.51%
Jun-08	334,428,490	22.7	71.5	111.65%	30	0	0	457,500	336	334,132,010	(296,481)	-0.09%
Jul-08	363,118,367	1.0	111.0	110.46%	31	0	0	458,750	352	366,033,366	(7,085,001)	-1.95%
Aug-08	341,326,026	12.7	64.0	111.88%	31	0	0	460,000	320	336,640,610	(4,685,417)	-1.37%
Sep-08	317,499,538	59.5	26.7	114.26%	30	1	0	461,250	336	314,208,950	(3,290,588)	-1.04%
Oct-08	310,230,042	278.6	0.0	110.62%	31	1	0	462,500	352	311,665,815	1,435,773	0.46%
Nov-08	313,840,850	451.6	0.0	111.72%	30	1	0	463,750	304	308,122,104	(5,718,745)	-1.82%
Dec-08	328,946,880	654.6	0.0	109.42%	31	0	0	465,000	336	335,662,939	6,716,060	2.04%

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	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Blackout Flag	Population	Number of Peak Hours	Predicted Purchases	Variances (kWh)	% Variance
Jan-09	340,125,286	830.2	0.0	108.49%	31	0	0	466,250	336	341,089,256	963,969	0.28%
Feb-09	298,423,228	606.4	0.0	109.78%	28	0	0	467,500	304	305,462,339	7,039,110	2.36%
Mar-09	317,878,968	515.6	0.0	110.52%	31	1	0	468,750	352	323,144,430	5,265,461	1.66%
Apr-09	288,048,157	295.9	1.2	109.12%	30	1	0	470,000	320	294,617,124	6,568,967	2.28%
May-09	279,549,261	158.8	6.9	108.77%	31	1	0	471,250	320	296,991,504	17,442,244	6.24%
Jun-09	301,280,403	49.3	34.2	108.14%	30	0	0	472,500	352	310,538,871	9,258,468	3.07%
Jul-09	312,634,481	6.2	43.7	107.09%	31	0	0	473,750	352	316,665,023	4,030,541	1.29%
Aug-09	342,969,587	9.8	91.0	108.47%	31	0	0	475,000	320	336,078,429	(6,891,158)	-2.01%
Sep-09	305,441,230	55.2	20.9	110.78%	30	1	0	476,250	336	299,633,119	(5,808,112)	-1.90%
Oct-09	307,520,270	287.8	0.0	108.83%	31	1	0	477,500	336	303,470,393	(4,049,877)	-1.32%
Nov-09	303,012,736	361.2	0.0	109.92%	30	1	0	478,750	320	300,322,276	(2,690,460)	-0.89%
Dec-09	331,058,361	631.3	0.0	107.65%	31	0	0	480,000	352	331,298,701	240,340	0.07%
Jan-10		726.4	0.0	107.89%	31	0	0	481,333	320	331,487,141	331,487,141	
Feb-10		639.6	0.0	108.13%	28	0	0	482,667	304	301,601,735	301,601,735	
Mar-10		559.5	0.0	108.37%	31	1	0	484,000	368	320,732,957	320,732,957	
Apr-10		331.8	1.3	108.61%	30	1	0	485,333	320	294,963,923	294,963,923	
May-10		165.2	12.0	108.85%	31	1	0	486,667	320	300,007,471	300,007,471	
Jun-10		41.7	55.5	109.09%	30	0	0	488,000	352	322,726,399	322,726,399	
Jul-10		5.5	109.4	109.34%	31	0	0	489,333	336	349,560,548	349,560,548	
Aug-10		11.9	89.9	109.58%	31	0	0	490,667	336	342,615,900	342,615,900	
Sep-10		81.2	28.2	109.82%	30	1	0	492,000	336	300,939,551	300,939,551	
Oct-10		265.0	2.1	110.07%	31	1	0	493,333	320	305,227,909	305,227,909	
Nov-10		426.3	0.0	110.31%	30	1	0	494,667	336	307,918,596	307,918,596	
Dec-10		620.9	0.0	110.56%	31	0	0	496,000	368	344,015,330	344,015,330	
Jan-11		726.4	0.0	110.85%	31	0	0	497,250	320	342,213,076	342,213,076	
Feb-11		639.6	0.0	111.14%	28	0	0	498,500	304	312,507,175	312,507,175	
Mar-11		559.5	0.0	111.43%	31	1	0	499,750	368	331,818,719	331,818,719	
Apr-11		331.8	1.3	111.72%	30	1	0	501,000	304	303,548,753	303,548,753	
May-11		165.2	12.0	112.02%	31	1	0	502,250	336	314,138,420	314,138,420	
Jun-11		41.7	55.5	112.31%	30	0	0	503,500	352	334,358,068	334,358,068	
Jul-11		5.5	109.4	112.61%	31	0	0	504,750	320	368,893,766	368,893,766	
Aug-11		11.9	89.9	112.90%	31	0	0	506,000	352	357,297,728	357,297,728	
Sep-11		81.2	28.2	113.20%	30	1	0	507,250	336	313,124,597	313,124,597	
Oct-11		265.0	2.1	113.50%	31	1	0	508,500	336	320,281,163	320,281,163	
Nov-11		426.3	0.0	113.80%	30	1	0	509,750	352	323,158,825	323,158,825	
Dec-11		620.9	0.0	114.09%	31	0	0	511,000	336	351,397,152	351,397,152	
		Weather Normalized										

	Actual	Predicted	Variance (kWh)	Variace %
2001	3,232,193,978	3,252,396,515	20,202,538	0.63%
2002	3,441,504,117	3,478,598,925	37,094,808	1.08%
2003	3,438,503,351	3,454,916,499	16,413,148	0.48%
2004	3,606,734,355	3,546,950,265	(59,784,089)	-1.66%
2005	3,848,828,345	3,794,122,112	(54,706,233)	-1.42%
2006	3,854,274,114	3,833,699,583	(20,574,530)	-0.53%
2007	3,958,591,768	3,988,592,061	30,000,293	0.76%
2008	3,915,443,564	3,915,428,135	(15,429)	0.00%
2009	3,727,941,968	3,759,311,464	31,369,495	0.84%
2010		**3,821,797,458**		
2011		**3,962,537,442**		

Total to 2009	33,024,015,560	33,024,015,560	0

Table 1 (page 4 of 4)

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.975540779
R Square	0.951679811
Adjusted R Square	0.947775149
Standard Error	6338765.087
Observations	108

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	8	7.83442E+16	9.79302E+15	243.7291315	1.43965E-61
Residual	99	3.97781E+15	4.01799E+13		
Total	107	8.2322E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-393051501	34097260.88	-11.52736293	5.29883E-20	-460707862.3	-325395139.7	-460707862.3	-325395139.7
Heating Degree Days	49250.10341	4133.362861	11.91526248	7.78792E-21	41048.61497	57451.59186	41048.61497	57451.59186
Cooling Degree Days	417362.9212	24902.15062	16.76011553	1.14106E-30	367951.6531	466774.1893	367951.6531	466774.1893
Ontario Real GDP Monthly %	351562161.2	28383405.24	12.38618687	7.71673E-22	295243328.9	407880993.6	295243328.9	407880993.6
Number of Days in Month	7933174.941	842061.7877	9.421131629	2.00401E-15	6262341.711	9604008.171	6262341.711	9604008.171
Spring Fall Flag	-12325307.36	1863586.4	-6.61375687	1.92427E-09	-16023066.99	-8627547.728	-16023066.99	-8627547.728
Blackout Flag	-22355282.21	6574206.887	-3.400453103	0.00097125	-35399934.62	-9310629.799	-35399934.62	-9310629.799
Population	20.55400628	33.2730722	0.617736954	0.538167151	-45.4669859	86.57499846	-45.4669859	86.57499846
Number of Peak Hours	167629.7331	40683.60417	4.120326517	7.86231E-05	86904.63811	248354.828	86904.63811	248354.828

VOLUME VARIANCE ANALYSIS

In accordance with the Chapter 2 Filing Requirements for Transmission and Distribution Applications, Hydro One Brampton has provided the following variance analysis based on the load forecast. Hydro One Brampton is of the view that variances for the Bridge and Test Years, represented in **Tables 5 and 6**, are reasonable and representative of historical year variances represented in **Tables 2, 3, and 4.**

Table 1: Historical Board Approved vs. Historical Actual 2006

		2006 Board Approved	2006 Actual	Variance	Variance %
kWh	Residential	989,558,788	1,041,609,067	(52,050,279)	-5.26%
	GS<50	276,748,729	282,703,766	(5,955,037)	-2.15%
	USL	-	5,294,847	(5,294,847)	-
kW	GS>50	2,771,782	2,962,866	(191,084)	-6.89%
	Intermediate	1,918,198	2,137,488	(219,290)	-11.43%
	Large Use	443,840	589,471	(145,631)	-32.81%
	Street Lighting	58,210	70,150	(11,940)	-20.51%

Table 2: Historical Actual 2007 vs. Historical Actual 2006

		2006 Actual	2007 Actual	Variance	Variance %
kWh	Residential	1,041,609,067	1,102,238,845	60,629,778	5.82%
	GS<50	282,703,766	298,781,693	16,077,927	5.69%
	USL	5,294,847	5,047,284	(247,563)	-4.68%
kW	GS>50	2,962,866	3,039,974	77,108	2.60%
	Intermediate	2,137,488	2,106,615	(30,873)	-1.44%
	Large Use	589,471	639,861	50,390	8.55%
	Street Lighting	70,150	76,385	6,235	8.89%

Table 3: Historical Actual 2008 vs. Historical Actual 2007

		2007 Actual	2008 Actual	Variance	Variance %
kWh	Residential	1,102,238,845	1,093,569,512	(8,669,333)	-0.79%
	GS<50	298,781,693	288,052,193	(10,729,500)	-3.59%
	USL	5,047,284	5,109,078	61,794	1.22%
kW	GS>50	3,039,974	3,064,109	24,135	0.79%
	Intermediate	2,106,615	1,976,551	(130,064)	-6.17%
	Large Use	639,861	712,935	73,074	11.42%
	Street Lighting	76,385	79,929	3,544	4.64%

Table 4: Historical Actual 2009 vs. Historical Actual 2008

		2008 Actual	2009 Actual	Variance	Variance %
kWh	Residential	1,093,569,512	1,088,557,819	(5,011,693)	-0.46%
	GS<50	288,052,193	278,899,780	(9,152,413)	-3.18%
	USL	5,109,078	5,104,985	(4,093)	-0.08%
kW	GS>50	3,064,109	3,049,119	(14,990)	-0.49%
	Intermediate	1,976,551	1,839,970	(136,581)	-6.91%
	Large Use	712,935	696,851	(16,084)	-2.26%
	Street Lighting	79,929	81,921	1,992	2.49%

Table 5: 2010 Bridge vs. Historical Actual 2009

		2009 Actual	2010 Bridge	Variance	Variance %
kWh	Residential	1,088,557,819	1,099,386,751	10,828,932	0.99%
	GS<50	278,899,780	285,620,803	6,721,023	2.41%
	USL	5,104,985	5,013,040	(91,945)	-1.80%
kW	GS>50	3,049,119	3,008,017	(41,102)	-1.35%
	Intermediate	1,839,970	1,844,198	4,228	0.23%
	Large Use	696,851	664,899	(31,952)	-4.59%
	Street Lighting	81,921	84,878	2,957	3.61%

Table 6: 2011 Test vs. 2010 Bridge

		2010 Bridge	2011 Test	Variance	Variance %
kWh	**Residential**	1,099,386,751	1,107,769,581	8,382,830	0.76%
	GS<50	285,620,803	290,725,436	5,104,633	1.79%
	USL	5,013,040	4,899,876	(113,164)	-2.26%
kW	**GS>50**	3,008,017	3,079,920	71,903	2.39%
	Intermediate	1,844,198	1,879,169	34,971	1.90%
	Large Use	664,899	697,451	32,552	4.90%
	Street Lighting	84,878	88,637	3,759	4.43%

HISTORICAL CONSUMPTION BY CUSTOMER CLASS

2003 kWh by Rate Class

	RES		GS<50	GS>50	Intermediate	Large Use	ST	TOTAL
January	95,835,825	626,894	27,500,623	103,812,165	69,160,178	24,321,611	2,167,609	323,424,905
February	80,671,677	626,894	24,649,021	89,968,164	64,846,317	23,902,704	1,773,999	286,438,776
March	76,572,741	626,894	22,593,439	79,323,772	71,031,338	27,167,404	1,628,909	278,944,497
April	67,295,647	626,894	20,913,735	80,475,757	67,817,496	25,659,378	1,480,278	264,269,185
May	63,501,813	626,894	19,396,111	86,801,807	71,284,663	25,865,193	1,335,937	268,812,418
June	61,838,475	626,894	19,680,025	71,035,189	71,972,313	26,315,987	1,084,101	252,552,984
July	91,204,614	626,894	22,400,150	89,670,036	75,348,788	24,717,308	1,149,708	305,117,498
August	92,505,717	626,894	22,935,141	83,412,431	67,701,528	24,908,899	1,382,361	293,472,971
September	78,427,414	626,894	20,985,776	82,575,759	72,293,429	16,357,992	1,426,706	272,693,970
October	65,785,373	626,894	18,551,752	80,094,441	73,731,928	18,989,015	1,739,816	259,519,219
November	67,288,556	626,894	19,615,385	77,560,779	72,072,312	22,055,175	1,918,897	261,137,998
December	77,572,801	626,894	22,202,955	71,302,549	67,861,111	21,523,662	2,022,585	263,112,557
	918,500,653	**7,522,732**	**261,424,109**	**996,032,849**	**845,121,401**	**281,784,328**	**19,110,906**	**3,329,496,978**

2004 kWh by Rate Class

	RES		GS<50	GS>50	Intermediate	LU	ST	TOTAL
January	96,703,333	484,803	25,198,404	104,155,437	73,019,151	24,579,195	2,339,254	326,479,579
February	84,636,166	484,803	24,601,914	83,965,294	74,306,616	21,771,547	1,849,319	291,615,660
March	69,377,651	484,803	20,291,117	89,048,340	80,324,216	24,118,324	2,000,257	285,644,709
April	79,244,091	484,803	23,310,697	79,946,850	75,392,433	23,755,274	1,508,105	283,642,254
May	67,852,563	484,803	20,851,513	82,215,365	76,804,104	25,169,695	1,332,471	274,710,514
June	64,151,147	484,803	19,775,019	84,705,901	78,795,472	24,604,867	1,171,956	273,689,166
July	82,824,898	484,803	23,407,892	103,637,673	78,785,577	24,024,195	1,225,790	314,390,830
August	87,422,441	484,803	21,702,502	72,323,870	81,182,471	26,255,685	1,522,854	290,894,625
September	81,041,314	484,803	22,094,454	86,541,954	78,802,148	24,812,636	1,653,445	295,430,754
October	70,172,958	484,803	20,496,344	81,302,933	77,944,388	24,236,905	1,990,409	276,628,740
November	66,697,051	484,803	19,326,591	87,516,368	77,098,968	24,232,445	2,098,851	277,455,078
December	83,125,206	484,803	23,059,907	90,347,619	70,508,590	22,764,334	2,272,059	292,562,518
	933,248,820	**5,817,642**	**264,116,354**	**1,045,707,603**	**922,964,134**	**290,325,102**	**20,964,771**	**3,483,144,427**

2005 kWh by Rate Class

	RES		GS<50	GS>50	Intermediate	LU	ST	TOTAL
January	101,234,974	460,681	26,413,664	90,654,817	74,924,606	25,094,959	2,257,824	321,041,525
February	86,270,169	460,681	24,209,751	92,165,629	72,579,489	22,740,386	1,879,556	300,305,661
March	79,078,475	460,681	23,356,969	90,387,744	77,590,145	24,524,462	1,857,430	297,255,906
April	79,227,360	460,681	23,467,108	82,584,190	76,171,266	24,015,019	1,585,420	287,511,044
May	68,385,013	460,681	21,653,135	84,462,278	78,587,389	25,166,564	1,429,477	280,144,537
June	82,879,065	460,681	23,105,684	91,804,571	84,433,776	27,545,365	1,274,605	311,503,747
July	128,480,389	460,681	27,817,309	93,000,462	82,486,731	24,358,531	1,383,628	357,987,731
August	112,838,134	460,681	25,240,068	95,085,316	87,931,959	28,296,971	1,585,446	351,438,575
September	96,349,384	460,681	25,129,040	92,220,235	80,458,193	26,483,669	1,735,399	322,836,601
October	75,430,792	460,681	22,187,363	85,901,855	84,066,210	26,468,231	2,147,735	296,662,867
November	72,376,973	460,681	21,544,106	94,121,175	82,152,106	25,672,569	2,296,094	298,623,704
December	83,759,829	460,681	23,959,908	90,803,584	72,679,213	24,055,634	2,475,807	298,194,656
	1,066,310,557	**5,528,171**	**288,084,106**	**1,083,191,856**	**954,061,083**	**304,422,360**	**21,908,421**	**3,723,506,554**

2006 kWh by Rate Class

	RES		GS<50	GS>50	Intermediate	LU	ST	TOTAL
January	98,458,355	441,237	26,342,127	91,006,867	79,832,837	25,883,694	2,449,965	324,415,081
February	83,349,754	441,237	24,334,630	89,730,272	74,288,762	26,895,910	2,026,621	301,067,188
March	80,562,836	441,237	22,842,106	91,160,102	79,825,722	29,311,710	2,009,462	306,153,176
April	83,837,908	441,237	24,484,168	81,677,835	71,937,804	27,935,602	1,711,887	292,026,441
May	63,141,914	441,237	20,077,050	85,898,181	82,894,338	29,701,827	1,558,834	283,713,381
June	83,998,828	441,237	23,159,975	94,949,357	84,053,496	30,003,381	1,382,389	317,988,664
July	111,186,033	441,237	25,589,655	95,157,357	83,247,742	26,457,504	1,495,087	343,574,615
August	117,709,184	441,237	24,941,826	96,099,149	86,520,259	30,727,075	1,704,572	358,143,302
September	86,607,920	441,237	23,753,486	84,139,055	79,514,748	28,545,776	1,959,235	304,961,457
October	67,558,810	441,237	20,343,436	92,550,026	79,385,482	27,003,715	2,320,051	289,602,757
November	77,795,336	441,237	22,286,617	89,930,687	77,636,545	26,317,950	2,491,478	296,899,850
December	87,402,189	441,237	24,548,690	88,518,985	71,280,858	25,303,578	2,681,665	300,177,203
	1,041,609,067	**5,294,847**	**282,703,766**	**1,080,817,874**	**950,418,593**	**334,087,722**	**23,791,245**	**3,718,723,113**

2007 kWh by Rate Class

	RES		GS<50	GS>50	Intermediate	LU	ST	TOTAL
January	93,319,105	420,607	24,217,862	95,905,359	77,848,769	23,769,132	2,596,873	318,077,707
February	102,055,857	420,607	27,955,450	94,967,064	73,114,414	25,338,044	2,209,984	326,061,421
March	86,845,356	420,607	24,862,108	93,112,013	79,724,488	30,151,983	2,254,407	317,370,961
April	82,760,074	420,607	24,158,560	87,588,401	75,290,160	27,510,198	1,961,246	299,689,247
May	70,077,887	420,607	22,556,027	89,096,126	82,233,255	31,774,021	1,741,549	297,899,473
June	91,697,027	420,607	25,108,174	92,943,751	83,601,152	32,819,475	1,574,224	328,164,410
July	105,258,833	420,607	25,225,027	93,132,732	79,006,485	31,987,996	1,641,016	336,672,696
August	114,216,996	420,607	25,638,509	95,744,190	88,403,082	27,313,857	1,793,222	353,530,462
September	103,891,690	420,607	26,519,148	88,944,043	79,588,558	31,047,408	2,004,251	332,415,705
October	73,007,108	420,607	21,442,804	91,831,259	81,578,086	31,276,234	2,476,296	302,032,395
November	80,052,239	420,607	23,927,702	92,467,921	77,468,830	30,161,601	2,655,570	307,154,471
December	99,056,672	420,607	27,170,321	94,058,516	64,191,071	32,156,310	2,877,555	319,931,053
	1,102,238,845	**5,047,284**	**298,781,693**	**1,109,791,374**	**942,048,351**	**355,306,260**	**25,786,193**	**3,839,000,000**

2008 kWh by Rate Class

	RES	Unmetered	GS<50	GS>50	Intermediate	LU	ST	TOTAL
January	98,653,851	425,757	25,297,276	99,785,778	72,886,783	32,686,172	2,837,550	332,573,168
February	100,180,658	425,757	26,787,609	95,821,284	68,211,314	32,565,026	2,414,791	326,406,438
March	94,619,366	425,757	25,978,438	97,233,384	71,242,085	31,924,884	2,349,819	323,773,733
April	75,036,348	425,757	21,711,709	90,369,347	75,551,403	31,010,582	1,947,145	296,052,291
May	76,482,957	425,757	22,827,002	83,820,542	73,945,733	31,781,176	1,727,582	291,010,748
June	83,870,856	425,757	23,084,622	97,910,575	75,663,049	34,728,380	1,531,842	317,215,081
July	107,087,354	425,757	25,056,366	93,105,375	77,902,130	33,375,552	1,650,786	338,603,319
August	112,579,437	425,757	25,682,934	93,074,996	77,402,658	35,669,308	1,904,602	346,739,691
September	92,228,481	425,757	22,978,221	93,319,171	75,559,205	34,156,534	2,161,515	320,828,883
October	76,305,160	425,757	21,975,784	88,838,844	73,286,480	32,419,478	2,569,368	295,820,871
November	87,253,832	425,757	23,186,829	89,213,855	69,094,325	30,549,526	2,742,070	302,466,194
December	89,271,212	425,757	23,485,403	94,458,541	61,841,877	27,834,347	2,956,012	300,273,148
	1,093,569,512	**5,109,078**	**288,052,193**	**1,116,951,693**	**872,587,042**	**388,700,963**	**26,793,084**	**3,791,763,566**

2009 kWh by Rate Class

	RES	Unmetered	GS<50	GS>50	Intermediate	LU	ST	TOTAL
January	114,929,995	425,415	27,400,043	98,470,898	62,466,253	30,269,110	2,869,091	336,830,805
February	100,314,756	425,415	26,081,128	89,223,138	59,894,713	27,575,448	2,376,729	305,891,327
March	84,993,353	425,415	22,596,221	93,267,497	66,945,485	30,119,516	2,368,403	300,715,890
April	89,892,055	425,415	23,554,666	85,881,705	62,607,105	27,295,581	1,986,143	291,642,670
May	77,171,913	425,415	21,218,838	82,709,262	64,769,595	21,729,889	1,767,971	269,792,883
June	71,910,668	425,415	20,134,165	88,276,045	66,245,644	25,383,350	1,562,749	273,938,036
July	96,389,222	425,415	23,117,924	90,697,163	69,334,333	28,839,597	1,693,925	310,497,579
August	106,837,454	425,415	31,105,213	92,877,653	71,088,497	31,566,349	1,948,305	335,848,886
September	92,707,816	425,415	15,244,145	89,536,165	69,913,251	30,593,880	2,214,309	300,634,981
October	80,822,498	425,415	22,169,993	87,178,137	68,128,434	30,638,512	2,651,495	292,014,484
November	84,768,126	425,415	22,777,478	88,350,312	66,028,714	27,681,172	2,835,538	292,866,755
December	87,819,963	425,415	23,499,971	94,539,745	60,763,420	30,830,986	3,068,768	300,948,268
	1,088,557,819	**5,104,985**	**278,899,780**	**1,081,007,720**	**788,185,444**	**342,523,390**	**27,343,426**	**3,611,622,564**

2003 KW by Rate Class

	GS>50	Intermediate	Large Use	ST	TOTAL
January	228,091	152,121	49,432	4,859	434,503
February	226,105	154,691	47,419	4,862	433,077
March	228,013	158,199	49,311	4,861	440,384
April	224,493	159,309	45,823	4,863	434,488
May	220,504	160,905	45,962	4,874	432,245
June	232,409	171,401	48,836	4,864	457,510
July	235,676	173,042	48,000	4,866	461,584
August	234,447	170,943	48,897	4,866	459,153
September	232,512	170,186	28,930	4,903	436,531
October	227,037	167,429	32,807	4,907	432,180
November	221,080	164,394	39,383	4,927	429,784
December	216,316	153,665	46,389	4,763	421,133
	2,726,683	**1,956,285**	**531,189**	**58,415**	**5,272,572**

2004 KW by Rate Class

	GS>50	Intermediate	Large Use	ST	TOTAL
January	231,787	166,256	42,040	4,940	445,023
February	227,922	171,354	37,730	4,954	441,960
March	225,728	173,500	40,399	4,960	444,587
April	200,145	174,346	40,107	4,967	419,565
May	238,313	174,522	42,150	4,970	459,955
June	243,761	178,672	48,129	4,998	475,560
July	240,028	183,630	39,508	5,017	468,183
August	240,178	180,263	45,961	5,054	471,456
September	241,622	180,232	44,541	5,117	471,512
October	234,200	178,269	41,126	5,128	458,723
November	230,873	172,315	40,622	5,158	448,968
December	238,116	171,603	42,688	5,211	457,618
	2,792,673	**2,104,962**	**505,001**	**60,474**	**5,463,110**

2005 KW by Rate Class

	GS>50	Intermediate	LU	ST	TOTAL
January	237,681	172,709	42,204	5,258	457,852
February	235,242	173,674	41,354	5,288	455,558
March	233,430	172,916	40,802	5,344	452,492
April	233,029	178,026	41,194	5,376	457,625
May	235,317	177,927	41,340	5,391	459,975
June	252,086	189,816	44,299	5,457	491,658
July	252,717	191,155	46,731	5,484	496,087
August	247,239	192,460	43,786	5,513	488,998
September	250,488	179,188	46,058	5,561	481,295
October	246,228	191,465	42,865	5,574	486,132
November	236,318	179,864	42,079	5,596	463,857
December	241,682	168,672	43,073	5,680	459,107
	2,901,457	**2,167,872**	**515,785**	**65,522**	**5,650,636**

2006 KW by Rate Class

	GS>50	Intermediate	LU	ST	TOTAL
January	236,221	174,648	42,359	5,730	458,958
February	240,459	175,085	49,949	5,744	471,237
March	237,612	171,688	49,261	5,765	464,326
April	235,064	166,087	49,703	5,768	456,622
May	245,850	188,905	50,635	5,789	491,179
June	261,826	183,101	49,691	5,787	500,405
July	266,072	187,617	51,473	5,828	510,990
August	260,654	189,939	51,199	5,859	507,651
September	242,459	181,115	51,764	5,940	481,278
October	254,597	175,253	48,350	5,958	484,158
November	239,883	171,163	47,473	5,967	464,486
December	242,169	172,887	47,614	6,015	468,685
	2,962,866	**2,137,488**	**589,471**	**70,150**	**5,759,975**

2007 KW by Rate Class

	GS>50	Intermediate	LU	ST	TOTAL
January	246,149	170,000	46,728	6,098	468,975
February	250,951	169,006	45,680	6,227	471,864
March	248,434	170,084	55,205	6,255	479,978
April	242,906	170,437	51,344	6,277	470,964
May	251,017	179,957	54,957	6,311	492,242
June	263,857	188,327	56,675	6,312	515,171
July	256,387	178,650	55,846	6,341	497,224
August	260,868	191,279	55,455	6,376	513,978
September	263,139	183,128	56,113	6,508	508,888
October	256,586	178,829	53,541	6,536	495,492
November	248,423	169,703	52,298	6,571	476,995
December	251,257	157,215	56,019	6,573	471,064
	3,039,974	**2,106,615**	**639,861**	**76,385**	**5,862,835**

2008 KW by Rate Class

	GS>50	Intermediate	LU	ST	TOTAL
January	255,704	162,567	57,398	6,603	482,272
February	254,190	156,802	56,212	6,612	473,816
March	253,203	156,406	57,242	6,619	473,470
April	252,368	167,983	58,743	6,625	485,719
May	248,343	165,407	59,034	6,627	479,411
June	265,813	177,293	63,496	6,627	513,229
July	258,298	174,090	64,260	6,649	503,297
August	260,311	173,203	61,551	6,689	501,754
September	264,444	172,361	61,243	6,697	504,745
October	246,511	162,041	59,199	6,716	474,467
November	253,311	157,513	56,454	6,728	474,006
December	251,613	150,885	58,103	6,737	467,338
	3,064,109	**1,976,551**	**712,935**	**79,929**	**5,833,524**

2009 KW by Rate Class

	GS>50	Intermediate	LU	ST	TOTAL
January	255,081	144,247	55,525	6,745	461,598
February	251,215	151,679	58,244	6,768	467,906
March	252,831	152,796	57,967	6,765	470,359
April	254,322	150,148	58,655	6,777	469,902
May	249,379	155,033	58,459	6,778	469,649
June	261,374	156,083	61,604	6,786	485,847
July	257,697	158,142	63,208	6,805	485,852
August	265,732	160,979	64,048	6,811	497,570
September	260,809	158,645	57,409	6,850	483,713
October	244,783	152,529	53,997	6,935	458,244
November	245,003	150,935	53,661	6,945	456,544
December	250,893	148,754	54,074	6,956	460,677
	3,049,119	**1,839,970**	**696,851**	**81,921**	**5,667,861**

CHANGE IN AVERAGE CONSUMPTION BY CUSTOMER CLASS

The average use per customer across the customer base of Hydro One Brampton has been steadily declining from approximately 2006 through to 2009. Hydro One Brampton is of the view that this decline can be predominantly attributed to CDM related initiatives that have encouraged customers from all rate classes to lower their consumption levels as well as to the impact of cooler summer temperatures experienced in 2008, and 2009.

The Street Lighting rate class is the only one of Hydro One Brampton's customer classes where the average use per customer has been continually increasing year over year. This increase is to be expected due to the structure of the Street Lighting class. The number of customers within this class remains at 2 while the number of street lights and connections continue to increase each year. While more electricity is consumed by the class each year, the number of customers remains stagnant.

The average consumption per customer on a per class basis is provided in the table below.

Table 1: Average kWh Consumption by Customer Class

	Residential	GS<50	USL	GS>50	Intermediate	LU	SL		Total
2003	10,020	40,147	6,808	733,771	6,711,752	70,446,082	9,555,453		33,038
2004	9,489	39,727	5,148	750,508	7,423,304	94,159,492	10,482,386		32,355
2005	10,173	41,802	4,770	794,275	7,917,519	101,474,120	10,954,211		32,559
2006	9,488	39,956	4,387	770,866	8,009,145	85,298,993	11,895,622		31,096
2007	9,659	40,961	4,038	783,290	8,063,181	72,265,680	12,893,097		30,909
2008	9,185	38,734	4,032	749,046	7,543,980	64,783,494	13,396,542		29,308
2009	8,993	37,045	3,988	695,778	6,918,965	57,087,232	13,671,713		27,460

DEVELOPMENT OF KILOWATT BILLING DETERMINANT

Hydro One Brampton has four rate classes that are charged for volumetric distribution on a per kW basis. These classes are as follows: General Service > 50 kW, General Service 700 to 4,999 kW (Intermediate), Large Use, and Streetlights. Since these classes are billed based on kW, their forecast must be converted to kW for rate setting purposes. The kW forecast for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh data to produce the required kW.

The following table outlines the annual demand units by applicable rate class.

Table 1: Historical Annual kW per Applicable Rate Class

Year	GS > 50	Intermediate	Large User	SL
2003	2,726,683	1,956,285	531,189	58,415
2004	2,792,673	2,104,962	505,001	60,474
2005	2,901,457	2,167,872	515,785	65,522
2006	2,962,866	2,137,488	589,471	70,150
2007	3,039,974	2,106,615	639,861	76,385
2008	3,064,109	1,976,551	712,935	79,929
2009	3.049,119	1,839,970	696,851	81,921

The following is the exponentially smoothed historical ratio of kW/kWh.

Exhibit 3 Tab 2 - Table 1: Smoothed Historical kW/kWh Ratio per Applicable Rate Class

Year	GS > 50	Intermediate	Large User	SL
2004	0.27%	0.23%	0.19%	0.31%
2005	0.27%	0.23%	0.18%	0.29%
2006	0.27%	0.23%	0.17%	0.30%
2007	0.27%	0.23%	0.18%	0.30%
2008	0.27%	0.22%	0.18%	0.30%
2009	0.27%	0.23%	0.18%	0.30%

The smoothed ratio for 2009 was applied to the weather normalized retail energy forecast in Table 3-19 in schedule 3 to provide the forecast of kW by rate class as shown below. The following outlines the forecast of kW for the applicable rate classes.

Table 2: kW Forecast by Applicable Rate Class

Year	GS > 50	Intermediate	Large User	SL	Total
2010	3,008,017	1,844,198	664,899	84,878	5,601,992
2011	3,079,920	1,879,169	697,451	88,637	5,745,176

EXHIBIT 3 TAB 3

THROUGHPUT REVENUES

REVENUE FORECASTING ANALYSIS

Table 1 in Exhibit 3 Tab 3 Schedule 2.0 below, summarizes HOBNI's total base distribution revenue requirement calculated on Hydro One Brampton's Normalized Historical Actual data for 2006 to 2009. The 2010 Bridge Year distribution revenue is the product of HOBNI's 2010 OEB approved rates and Hydro One Brampton's forecast billing determinants. The proposed distribution revenue for 2011 is the product of the 2011 proposed distribution rates and 2011 forecast billing determinants per Exhibit 3 Tab 2 above.

Hydro One Brampton also, is an embedded distributor and pays Hydro One Networks Inc. (HONI) for the use of their low voltage distribution system. The table below shows the Low Voltage (LV) Charges for the 2011 Test Year to be zero as Hydro One Brampton has not requested a variable rate adder for Low Voltage charges and has filed to dispose of these costs as described in Exhibit 9 Tab 1.

THROUGHPUT REVENUE

Hydro One Brampton's throughput revenues are based on weather normalized historical actual kWh and kW billing determinants. Throughput revenues have been calculated based on the appropriate OEB approved rates for the applicable rate year multiplied by the historical actual (calendar year) weather normalized billing determinants.

SMART METER RATE RIDERS IN THROUGHPUT REVENUE

For consistency with information filed in the Revenue Requirement Model, the Smart Meter Rate Riders/Adders have been included in the throughput rates for 2006 through to 2010 as Hydro One Brampton is seeking final disposition of the balances of the Smart Meter Deferral and Variance Accounts, USoA accounts 1555 and 1556 for the period ending December 31, 2009.

REVENUE THROUGHPUTS VARIANCE ANALYSIS

Hydro One Brampton's distribution revenue and variances for 2006 OEB Approved, 2006 to 2009 Actual, and 2010 Bridge Year and 2011 Test Year have been calculated using the OEB-approved distribution rates in affect for the rate year shown in Table 1 on the following page. The 2011 distribution revenue has been calculated using the rates proposed in this Application. Distribution revenue does not include commodity-related revenue. The volumetric data used to calculate the base distribution revenue has been weather normalized, for variance analysis, in accordance with the Filing Requirements.

VARIANCE ANALYSIS

Consistent with the materiality thresholds set out in the Filing Requirements with respect to rate base and operating costs, Hydro One Brampton has used a variance of 0.5% of Distribution Revenue Requirement including LV charges, to determine the threshold for variance analysis. Table 1 below provides a summary of all variances by customer class. Note the variances highlighted are ones that exceed the materiality threshold. The thresholds used by year have been used to delineate the variances that require further explanations. A variance analysis table is provided below for each customer class (except the Unmetered Scattered Load Class) and the variance is explained in two components: a volumetric variance and a price variance. The volumetric variance is calculated as the difference in usage and the difference in the customer counts year over year times the variable or fixed distribution charge, (i.e. change in volume). The price variance is calculated based on the usage and customer counts times the difference in the distribution variable and fixed rate year over year, (i.e. change in price).

Table 1: Distribution Revenue Throughput Analysis

	2006 OEB Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge	Variance	2011 Test Year	Variance
Distribution Revenue:													
Residential	28,804,232	30,932,917	2,128,685	32,750,248	1,817,331	33,477,545	727,297	34,505,113	1,027,567	33,965,375	(539,738)	33,913,877	(51,498)
General Service < 50 kW	6,753,149	6,947,577	194,428	7,271,249	323,672	7,120,105	(151,145)	7,141,502	21,398	7,056,544	(84,958)	6,609,534	(447,010)
General Service > 50 kW	8,234,737	8,721,459	486,722	8,926,700	205,242	9,031,596	104,895	9,116,566	84,970	8,800,962	(315,604)	10,658,221	1,857,260
Intermediate	9,443,369	10,229,530	786,161	10,037,773	(191,758)	9,531,806	(505,967)	9,022,443	(509,363)	8,757,052	(265,391)	8,814,322	57,270
Large Use (> 5000 kW)	1,494,553	1,978,758	484,205	2,176,059	197,300	2,458,612	282,553	2,421,613	(36,999)	2,269,815	(151,798)	2,134,272	(135,544)
Street Lighting	132,445	158,530	26,085	171,740	13,211	179,273	7,532	183,904	4,632	187,121	3,217	1,883,527	1,696,406
Unmetered Scattered Load	0	114,457	114,457	109,696	(4,762)	108,956	(739)	108,693	(263)	104,345	(4,348)	127,659	23,315
Low Voltage Adder to Rates	(94,500)	(65,797)	28,703	(67,103)	(1,306)	(68,221)	(1,119)	(67,065)	1,156	(65,742)	1,324	0	65,742
Gross Distribution Revenue	**54,767,985**	**59,017,432**	**4,249,447**	**61,376,363**	**2,358,931**	**61,839,671**	**463,309**	**62,432,770**	**593,098**	**61,075,472**	**(1,357,298)**	**64,141,412**	**3,065,940**
Less Transformer Allowances:													
General Service > 50 kW	(131,573)	(150,444)	(18,871)	(151,490)	(1,047)	(154,561)	(3,070)	(165,050)	(10,490)	(154,441)	10,609	(189,813)	(35,371)
Intermediate	(1,036,718)	(1,054,929)	(18,211)	(1,027,595)	27,334	(992,921)	34,674	(910,766)	82,155	(910,414)	352	(1,384,095)	(473,681)
Large Use (> 5000 kW)	(299,984)	(356,257)	(56,273)	(402,052)	(45,796)	(429,316)	(27,264)	(421,343)	7,973	(398,939)	22,404	0	398,939
Total Transformer Allowances	(1,468,274)	(1,561,629)	(93,355)	(1,581,138)	(19,509)	(1,576,798)	4,340	(1,497,160)	79,639	(1,463,795)	33,365	(1,573,908)	(110,113)
Net Base Distribution Revenue	53,299,711	57,455,803	4,156,092	59,795,225	2,339,422	60,262,873	467,649	60,935,610	672,737	59,611,677	(1,323,933)	62,567,504	2,955,827

Note: Highlighted cells indicate variances above materiality threshold.

Revenue Throughput Variance Analysis for the 2006 OEB Approved, the 2006 to 2009 Actual, 2010 Bridge Year and the 2011 Test year at proposed rates.

Table 2: Distribution Revenue Variance Analysis Residential Class

	2006 OEB Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge	Variance	2011 Test Year	Variance
Residential Class													
Volume Variance													
kWh Volume	989,558,788	1,038,010,880	765,968	1,073,605,053	565,947	1,098,553,263	391,687	1,107,022,662	132,970	1,099,386,751	(117,593)	1,107,769,581	134,125
Number of Customers Volume	1,224,840	1,317,338	1,019,761	1,369,426	596,408	1,428,720	673,580	1,452,490	280,248	1,468,519	185,935	1,483,920	168,023
Total Volume Variance			1,785,729		1,162,355		1,065,267		413,218		68,342		302,148
Price Variance													
Variable Price Variance	0.0158	0.0158	0	0.0159	94,689	0.0157	(214,721)	0.0157	0	0.0154	(332,107)	0.0160	659,632
Fixed Price Variance	10.74	11.02	342,955	11.45	560,287	11.36	(123,248)	11.79	614,350	11.60	(275,973)	10.91	(1,013,278)
Total Price Variance			342,955		654,976		(337,969)		614,350		(608,080)		(353,646)
Total Residential Class Variance			2,128,685		1,817,331		727,297		1,027,567		(539,738)		(51,498)

Note: Highlighted cells indicate variances above materiality threshold.

Variances for the Residential Class explained above due to volume and price variances.

Table 3: Distribution Revenue Variance Analysis General Service < 50 kW Class

	2006 OEB Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge	Variance	2011 Test Year	Variance
General Service < 50 kW													
Volume Variance													
kWh Volume	276,748,729	283,269,385	118,993	294,976,207	214,235	288,850,579	(110,874)	286,543,458	(41,759)	285,620,803	(16,423)	290,725,436	84,737
Number of Customers Volume	82,404	84,904	52,362	87,532	56,239	89,241	36,231	90,345	23,891	92,736	50,856	94,715	37,274
Total Volume Variance			171,355		270,474		(74,643)		(17,868)		34,432		122,011
Price Variance													
Variable Price Variance	0.0182	0.0182	0	0.0183	14,565	0.0181	(58,995)	0.0181	0	0.0178	(85,963)	0.0166	(342,745)
Fixed Price Variance	20.66	20.94	23,073	21.40	38,633	21.20	(17,506)	21.64	39,266	21.27	(33,428)	18.83	(226,276)
Total Price Variance			23,073		53,198		(76,502)		39,266		(119,391)		(569,021)
Total General Service < 50 kW Class Variance			194,428		323,672		(151,145)		21,398		(84,958)		(447,010)

Note: Highlighted cells indicate variances above materiality threshold.

Variances are explained in above table. For 2007 Actual vs. 2006 Actual, the majority of variance relates to kWh volume. Variances for 2011 Test Year vs. 2010 Bridge Year mainly attributable to price variances for both fixed and variable rates due to revenue/cost ratio change in class.

1

Table 4: Distribution Revenue Variance Analysis General Service > 50 kW Regular Class

	2006 OEB Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge	Variance	2011 Test Year	Variance
General Service > 50 kW													
Volume Variance													
kW Volume	2,771,782	2,962,962	449,430	3,025,944	148,594	3,073,013	109,826	3,069,157	(9,006)	3,008,017	(140,224)	3,079,920	196,072
Number of Customers Volume	16,512	16,825	32,668	17,002	18,610	17,894	92,786	18,644	78,398	18,524	(12,292)	18,627	12,406
Total Volume Variance			482,098		167,204		202,612		69,391		(152,515)		208,477
Price Variance													
Variable Price Variance	2.3508	2.3508	0	2.3593	25,106	2.3333	(78,675)	2.34	6,453	2.29	(128,598)	2.7269	1,303,675
Fixed Price Variance	104.09	104.37	4,623	105.14	12,932	104.02	(19,042)	104.53	9,126	102.68	(34,491)	121.31	345,108
Total Price Variance			4,623		38,038		(97,717)		15,579		(163,089)		1,648,782
Total General Service > 50 kW Class Variance			486,722		205,242		104,895		84,970		(315,604)		1,857,260

Note: Highlighted cells indicate variances above materiality threshold.

2 Variances are explained in above table. For 2006 Actual vs. 2006 OEB Approved majority of variance relate to kW volume. Variances for 2011 Test Year vs. 2010 Bridge Year
3 mainly attributable to price variances for both fixed and variable rates due to revenue/cost ratio change in class per the Cost Allocation Study.

Table 5: Distribution Revenue Variance Analysis General Service > 50 kW Intermediate Class

	2006 OEB Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge	Variance	2011 Test Year	Variance
General Service > 50 kW Intermediate													
Volume Variance													
kW Volume	1,918,198	2,133,992	826,238	2,082,670	(197,210)	1,983,878	(375,439)	1,855,503	(488,300)	1,844,198	(42,229)	1,879,169	132,494
Number of Customers Volume	1,452	1,424	(40,483)	1,402	(31,931)	1,388	(20,097)	1,367	(30,181)	1,323	(61,402)	1,271	(69,388)
Total Volume Variance			785,755		(229,141)		(395,536)		(518,481)		(103,632)		63,106
Price Variance													
Variable Price Variance	3.8288	3.8288	0	3.8426	29,402	3.8003	(88,097)	3.8037	6,745	3.7355	(126,545)	3.7887	98,111
Fixed Price Variance	1,445.54	1,445.82	407	1,451.43	7,982	1,435.50	(22,334)	1,437.21	2,373	1,411.45	(35,214)	1,332.91	(103,947)
Total Price Variance			407		37,384		(110,431)		9,119		(161,759)		(5,836)
Total General Service > 50 kW Intermediate Class Variance			786,161		(191,758)		(505,967)		(509,363)		(265,391)		57,270

Note: Highlighted cells indicate variances above materiality threshold.

Variances are explained in above table. For 2006 Actual vs. 2006 OEB Approved majority of variance relate to kW volume. Unfavourable Variances for 2008 Actual vs. 2007 Actual and 2009 Actual vs. 2008 Actual relate mainly to lower kW volumes.

Table 6: Distribution Revenue Variance Analysis Large User Class

	2006 OEB Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge	Variance	2011 Test Year	Variance
Large User													
Volume Variance													
kW Volume	443,840	588,710	430,951	632,888	131,889	715,527	244,000	702,238	(39,273)	664,899	(108,370)	697,451	82,113
Number of Customers Volume	36	47	53,244	59	58,299	72	62,463	72	0	72	0	72	0
Total Volume Variance			484,195		190,188		306,463		(39,273)		(108,370)		82,113
Price Variance													
Variable Price Variance	2.9747	2.9747	0	2.9854	6,273	2.9526	(20,759)	2.9553	1,932	2.90	(37,219)	2.5225	(252,529)
Fixed Price Variance	4,840.07	4,840.35	10	4,858.22	840	4,804.82	(3,151)	4,809.57	342	4,723.33	(6,209)	5,207.66	34,872
Total Price Variance			10		7,113		(23,909)		2,274		(43,428)		(217,657)
Total Large User Class Variance			484,205		197,300		282,553		(36,999)		(151,798)		(135,544)

Note: Highlighted cells indicate variances above materiality threshold.

Variances are explained in above table. For 2006 Actual vs. 2006 OEB Approved majority of variance relate to kW volume.

Table 7: Distribution Revenue Variance Analysis Streetlighting Class

Streetlighting													
Volume Variance													
kW Volume	58,210	70,150	26,980	75,730	12,654	79,929	9,418	81,921	4,472	84,878	6,518	88,637	51,134
Number of Customers Volume	339,899	411,853	0	429,150	0	447,174	0	465,951	0	485,513	0	505,899	27,317
Total Volume Variance			26,980		12,654		9,418		4,472		6,518		78,451
Price Variance													
Variable Price Variance	2.2596	2.2596	0	2.2678	572	2.2429	(1,886)	2.2449	160	2.2046	(3,301)	13.6018	967,368
Fixed Price Variance	0.00	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	1.34	650,588
Total Price Variance			0		572		(1,886)		160		(3,301)		1,617,955
Total Streetlighting Class Variance			26,980		13,227		7,532		4,632		3,217		1,696,406

Note: Highlighted cells indicate variances above materiality threshold.

Variances are explained in above table. For 2011 Test Year vs. 2010 Bridge Year the majority of the variance relates to price variances caused by price changes as the result of changes to Revenue/Cost Ratios per the Cost Allocation Study.

TRANSFORMER ALLOWANCE VARIANCES

As discussed in Exhibit 7 in this application, Hydro One Brampton is implementing cost allocation related adjustments to transformer allowances as part of this Application.

The $/kW transformer allowances charges have been revised for the following classes:

Large User Class

In the course of its review of cost allocation among its customer classes, Hydro One Brampton has determined that the Large Use transformer allowance is no longer applicable to that class, for reasons discussed in Exhibit 7 and in Hydro One Brampton's revised cost allocation study, being filed as an Appendix thereto. As there will be no Hydro One Brampton transformation costs assigned to this customer class as of the 2011 rate year, those customers will not be entitled to a credit against any such costs, since those costs are not allocated to the Large Use Class. The removal of the Large User transformer allowance reduces Hydro One Brampton's total transformer allowance payments offset by a reduction to the Large User Class variable Distribution Rate. This change is revenue neutral to the Company and to the customers in this class. The variance of $398,939 for 2011 Test Year vs. 2010 Bridge Year is attributable to the elimination of the transformer allowance.

General Service > 50 kW

Current transformer allowance changes from $0.60/kW to $0.7202/kW to better reflect Hydro One Brampton's costs to provide transformation to this class of customers.

General Service 700 to 4,999 kW

Current transformer allowance changes from $0.60/kW to $0.8952/kW to better reflect the Company's costs to provide transformation to this class of customers. The variance of $473,681 for 2011 Test Year vs. 2010 Bridge Year is attributable to the increase in transformer allowance per kW.

EXHIBIT 3 TAB 4

OTHER REVENUE

SUMMARY OF OTHER DISTRIBUTION REVENUE

This Exhibit provides the details on Hydro One Brampton's other distribution revenue. Other Revenues include OEB approved specific service charges, rent from electric property, late payment charges, Standard Supply Service (SSS) administration charges, retail service revenues, interest and other miscellaneous revenues. The table below provides a summary by year of information that is detailed in **Exhibit 3-Tab 4-Schedule 1.1-Table 1** on the following page.

Table 1: Summary of Distribution

Description	2006 Board Approved	Actual - 2006	Actual - 2007	Actual - 2008	Actual - 2009	Bridge Year 2010	Test Year 2011
Other Distribution Revenue							
SSS Administration Charge	247,340	280,415	311,193	314,944	309,221	312,834	316,281
Specific Service Charges	1,185,932	1,348,713	1,458,177	1,299,510	1,107,039	1,188,970	1,152,000
Late Payment Charges	866,886	1,090,020	1,220,696	1,219,746	1,314,408	1,310,000	1,450,331
Other Distribution Revenue	447,959	1,604,151	977,757	907,336	865,471	915,030	813,000
Other Income and Expenses	260,321	769,392	603,239	319,883	193,780	156,680	254,799
Total	**3,008,438**	**5,092,690**	**4,571,062**	**4,061,417**	**3,789,918**	**3,883,514**	**3,986,412**

Variance analysis information is provided in Tab 4 Schedule 2.0 of this Exhibit.

OTHER OPERATING REVENUE

1 **Table 2,** below, provides the breakdown of other distribution revenue, by account.

Table 1: Summary of Other Distribution Revenue

Uniform System of Account #	OEB #	OEB Description	2006 Board Approved	Actual - 2006	Actuals - 2007	Actuals - 2008	Actuals - 2009	Bridge Year - 2010	Test Year - 2011
4235	4235	Specific Service Charges	1,185,932	1,348,713	1,458,177	1,299,510	1,107,039	1,188,970	1,152,000
4225	4225	Late Payment Charges	866,886	1,090,020	1,220,696	1,219,746	1,314,408	1,310,000	1,450,331
4080	4080	SSS Administration Charges	247,340	280,415	311,193	314,944	309,221	312,834	316,281
4082	4082	Retail Services Revenues	240,751	260,051	293,177	305,716	285,754	350,000	310,000
4084	4084	Service Transaction Requests (STR) Revenues	1,433	12,485	20,825	13,850	4,200	25,000	5,000
4090	4090	Electric Services Incidental to Energy Sales	-	579,200	(69,564)	12,652	17,997	-	-
4205	4205	Interdepartmental Rents	-	-	-	-	-	-	-
4210	4210	Rent from Electric Property	205,775	752,415	733,319	575,118	557,520	540,030	498,000
4215	4215	Other Utility Operating Income	-	-	-	-	-	-	-
4220	4220	Other Electric Revenues	-	-	-	-	-	-	-
4240	4240	Provision for Rate Refunds	-	-	-	-	-	-	-
4245	4245	Government Assistance Directly Credited to Income	-	-	-	-	-	-	-
		Subtotal Other Distribution Revenues	**695,299**	**1,884,566**	**1,288,950**	**1,222,280**	**1,174,692**	**1,227,864**	**1,129,281**
4305	4305	Regulatory Debits	-	-	-	-	-	-	-
4310	4310	Regulatory Credits	-	-	-	-	-	-	-
4315	4315	Revenues form Electric Plant Leased to Others	-	-	-	-	-	-	-
4320	4320	Expenses of Electric Plant Leased to Others	-	-	-	-	-	-	-
4325	4325	Revenues from Merchandise. Jobbing, Etc.	14,131	-	-	-	-	-	-
4330	4330	Costs and Expenses of Merchandising, Jobbing, Etc.	-	-	-	-	-	-	-
4335	4335	Profits and Losses from Financial Instrument Hedges	-	-	-	-	-	-	-
4340	4340	Profits and Losses from Financial Instrument Investments	-	-	-	-	-	-	-
4345	4345	Gains from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-
4350	4350	Losses from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-
4355	4355	Gain on Disposition of Utility and Other Property	27,077	143,739	3,117	14,384	6,365	-	-
4360	4360	Loss on Disposition of Utility and Other Property	-	(23,353)	(21,060)	(113,741)	(2,506)	-	-
4365	#N/A	Gains from Disposition of Allowances for Emission	-	-	-	-	-	-	-
4370	#N/A	Losses from Disposition of Allowances for Emission	-	-	-	-	-	-	-
4375	4375	Revenues from Non-Utility Operations	-	-	-	-	-	-	-
4380	4380	Expenses of Non-Utility Operations	-	-	(64,764)	(105,495)	(5,157)	-	-
4385	4385	Non-Utility Rental Income	-	-	-	-	-	-	-
4390	4390	Miscellaneous Non-Operating Income	66,326	124,065	209,370	222,693	152,191	150,000	252,000
4395	4395	Rate-Payer Benefit Including Interest	-	-	-	-	-	-	-
4398	4398	Foreign Exchange Gains and Losses, Including Amortization	-	597	(4,742)	(20,387)	16,083	-	-
4405	4405	Interest and Dividend Income	152,787	524,343	481,318	322,429	26,803	6,680	2,799
4415	#N/A	Equity in Earnings of Subsidiary Companies	-	-	-	-	-	-	-
		Subtotal Other Income and Expenses	**260,321**	**769,392**	**603,239**	**319,883**	**193,780**	**156,680**	**254,799**
		TOTAL OTHER OPERATING REVENUE	**3,008,438**	**5,092,690**	**4,571,062**	**4,061,417**	**3,789,918**	**3,883,514**	**3,986,412**

Table 2, below, below provides a further breakdown of specific service charges.

Table 2: Summary of Specific Service Charges

Description	2006	2007	2008	2009	2010 Bridge Year	2011 Test Year
Arrears certificate	60					
Statement of account						
Pulling post dated cheques	15	15	-	-		
Duplicate invoices for previous billing	480	495	435	330	444	500
Request for other billing information	90	15	30	-	31	
Easement letter	15	-	-	-		
Income tax letter	195	345	375	405	383	500
Notification charge	-	-	-	-		
Account history	285	330	495	240	505	500
Credit reference/credit check (plus credit agency costs)	7,380	9,720	9,735	9,075	9,930	10,129
Returned cheque charge (plus bank charges)	38,520	39,280	33,760	32,220	34,518	35,124
Charge to certify cheque	-	-	-	-		
Legal letter charge	4,096	2,398	2,092	980	2,135	1,530
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	469,424	705,107	666,853	500,820	520,000	530,400
Special meter reads	-	30	-	60		
Collection of account charge - no disconnection	330,656	543,560	515,025	547,290	550,000	561,000
Collection of account charge - no disconnection - after regular hours						
Disconnect/Reconnect at meter - during regular hours						
Install/Remove load control device - during regular hours						
Disconnect/Reconnect at meter - after regular hours	5,550	-	-	-	-	
Install/Remove load control device - after regular hours	-	3,420	155	-		
Disconnect/Reconnect at pole - during regular hours						
Disconnect/Reconnect at pole - after regular hours	370	740	925	925	-	
Meter dispute charge plus Measurement Canada fees (if meter found correct)						
Service call - customer-owned equipment						
Service call - after regular hours						
Temporary service install & remove - overhead - no transformer						
Temporary service install & remove - underground - no transformer						
Temporary service install & remove - overhead - with transformer						
Specific Charge for Access to the Power Poles $/pole/year						
SSS Administration						
Retail Service Revenues						
STR Revenues						
Late Payment Charges						
Electric Services Incidental to Energy Charges						
Rental from Electric Property						
Rental Income Other						
Scrap Sales						
Theft of Power Recovery						
Interest Income						
Cash discounts	27,444	13,138		3,581		
Admin Charge	6,835	4,650	5,174	6,146	5,277	5,653
Miscellaneous Income		24,190	1,400		1,429	
Misc Energy Charges						
Special Charges	5,674	225	180	90	184	
Miscellaneous Energy Charges (Was Bell Co)	445,666	103,453	55,907	-	57,025	
Special Charges (Was City - Coll. Of Bills)		1,937	1,834	1,477	1,871	1,908
Pool Approvals (Was Cafeteria Revenue)	4,158	4,200	2,725	2,125	2,780	2,836
Tenders (Was Daycare Revenue)	1,200	450	850	675	867	900
Owner Requested Disconnect/Reconnect	600	480	1,560	600	1,591	1,020
Total Other Revenues	1,348,713	1,458,177	1,299,510	1,107,039	1,188,970	1,152,000

OTHER DISTRIBUTION REVENUE VARIANCE ANALYSIS

The following table provides Hydro One Brampton's other distribution revenue for 2006 - 2009 Actual, 2010 bridge Year, 2011 test year, and the following variances:

- 2007 Actual against 2006 Actual;
- 2008 Actual against 2007 Actual;
- 2009 Actual against 2008 Actual;
- 2010 Bridge Year against 2009 Actual; and
- 2011 Test Year against 2010 Bridge Year

Table 1: Summary of Other Revenue and Variance

Description	2006 Board Approved	Actual - 2006	Actual - 2007	Variance from 2006 Actual	Actual - 2008	Variance from 2007 Actual	Actual - 2009	Variance from 2008 Actual	Bridge Year 2010	Variance from 2009 Actual	Test Year - 2011	Variance from 2010 Bridge
SSS Administration Charges	247,340	280,415	311,193	30,778	314,944	3,751	309,221	(5,723)	312,834	3,613	316,281	3,447
Specific Service Charges	1,185,932	1,348,713	1,458,177	109,464	1,299,510	(158,667)	1,107,039	(192,470)	1,188,970	81,931	1,152,000	(36,970)
Late Payment Charges	866,886	1,090,020	1,220,696	130,677	1,219,746	(951)	1,314,408	94,662	1,310,000	(4,408)	1,450,331	140,331
Other Distribution Revenue	447,959	1,604,151	977,757	(626,394)	907,336	(70,422)	865,471	(41,865)	915,030	49,559	813,000	(102,030)
Other Income and Expenses	260,321	769,392	603,239	(166,153)	319,883	(283,356)	193,780	(126,103)	156,680	(37,100)	254,799	98,119
Total	3,008,438	5,092,690	4,571,062	(521,628)	4,061,417	(509,645)	3,789,918	(271,499)	3,883,514	93,596	3,986,412	102,898

The Materiality threshold used to analyze Other Distribution Revenue is $ 300,000 consistent with the threshold used throughout this application.

OTHER DISTRIBUTION REVENUE – 2007 ACTUAL AGAINST 2006 ACTUAL

This category had a decrease in revenue of $626,394. In 2006, revenue included cost recoveries for the Jim Yarrow Transformer Station (OEB account 4090) totalling $579,200.

Table 2: Other Revenue Variances on the following page provides details of variances by account:

Table 2: Other Revenue Variances

Uniform System of Account #	OEB Description	2006 Board Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge Actual	Variance	2011 Test Year	Variance
4235	Specific Service Charges	1,185,932	1,348,713	162,781	1,458,177	109,464	1,299,510	(158,667)	1,107,039	(192,470)	1,188,970	81,931	1,152,000	(36,970)
4225	Late Payment Charges	866,886	1,090,020	223,134	1,220,696	130,677	1,219,746	(951)	1,314,408	94,662	1,310,000	(4,408)	1,450,331	140,331
4080	SSS Administration Charges	247,340	280,415	33,075	311,193	30,778	314,944	3,751	309,221	(5,723)	312,834	3,613	316,281	3,447
4082	Retail Services Revenues	240,751	260,051	19,300	293,177	33,126	305,716	12,539	285,754	(19,962)	350,000	64,246	310,000	(40,000)
4084	Service Transaction Requests (STR) Revenues	1,433	12,485	11,052	20,825	8,340	13,850	(6,975)	4,200	(9,650)	25,000	20,800	5,000	(20,000)
4090	Electric Services Incidental to Energy Sales	-	579,200	579,200	(69,564)	(648,764)	12,652	82,215	17,997	5,345	-	(17,997)	-	-
4205	Interdepartmental Rents	-	-	-	-	-	-	-	-	-	-	-	-	-
4210	Rent from Electric Property	205,775	752,415	546,640	733,319	(19,096)	575,118	(158,200)	557,520	(17,598)	540,030	(17,490)	498,000	(42,030)
4215	Other Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-	-	-
4220	Other Electric Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
4240	Provision for Rate Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-
4245	Government Assistance Directly Credited to Income	-	-	-	-	-	-	-	-	-	-	-	-	-
4305	Regulatory Debits	-	-	-	-	-	-	-	-	-	-	-	-	-
4310	Regulatory Credits	-	-	-	-	-	-	-	-	-	-	-	-	-
4315	Revenues form Electric Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-	-	-
4320	Expenses of Electric Plant Leased to Others	-	-	-	-	-	-	-	-	-	-	-	-	-
4325	Revenues from Merchandise. Jobbing, Etc.	14,131	-	(14,131)	-	-	-	-	-	-	-	-	-	-
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	-	-	-	-		-	-	-	-	-	-	-	-
4335	Profits and Losses from Financial Instrument Hedges	-	-	-	-	-	-	-	-	-	-	-	-	-
4340	Profits and Losses from Financial Instrument Investments	-	-	-	-	-	-	-	-	-	-	-	-	-
4345	Gains from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
4350	Losses from Disposition of Future Use Utility Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
4355	Gain on Disposition of Utility and Other Property	27,077	143,739	116,662	3,117	(140,623)	14,384	11,267	6,365	(8,019)	-	(6,365)	-	-
4360	Loss on Disposition of Utility and Other Property	-	(23,353)	(23,353)	(21,060)	2,293	(113,741)	(92,681)	(2,506)	111,235	-	2,506	-	-
4365	Gains from Disposition of Allowances for Emission	-	-	-	-		-	-	-	-	-	-	-	-
4370	Losses from Disposition of Allowances for Emission	-	-	-	-		-	-	-	-	-	-	-	-
4375	Revenues from Non-Utility Operations	-	-	-	-	-	-	-	-	-	-	-	-	-
4380	Expenses of Non-Utility Operations	-	-	-	(64,764)	(64,764)	(105,495)	(40,731)	(5,157)	100,338	-	5,157	-	-
4385	Non-Utility Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-
4390	Miscellaneous Non-Operating Income	66,326	124,065	57,740	209,370	85,304	222,693	13,323	152,191	(70,502)	150,000	(2,191)	252,000	102,000
4395	Rate-Payer Benefit Including Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	-	597	597	(4,742)	(5,339)	(20,387)	(15,645)	16,083	36,470	-	(16,083)	-	-
4405	Interest and Dividend Income	152,787	524,343	371,556	481,318	(43,024)	322,429	(158,890)	26,803	(295,625)	6,680	(20,123)	2,799	(3,881)
4415	Equity in Earnings of Subsidiary Companies	-	-	-	-		-	-	-	-	-	-	-	-
	TOTAL OTHER REVENUE	3,008,438	5,092,690	2,084,252	4,571,062	(521,628)	4,061,417	(509,645)	3,789,918	(271,499)	3,883,514	93,596	3,986,412	102,898

RATE OF RETURN ON NON-CORE ACTIVITIES

Hydro One Brampton has not had any Non-Core Activities during this period and as such there will be no rate of return.

NEW PROPOSED SPECIFIC SERVICE CHARGES

Hydro One Brampton is not requesting any new Specific Service Charges.

EXHIBIT 4

OPERATING COSTS

EXHIBIT 4 TAB 1

MANAGER'S SUMMARY

OM&A TEST YEAR LEVELS

Hydro One Brampton is currently one of the most efficient lowest-cost utilities in the Province while maintaining a high level of reliability and workforce stability. A result accomplished by leveraging the synergy's and efficiencies of being a subsidiary of a large organization, contracting out when there is an economic benefit to be derived and by working in partnership with unions to provide reliable and quality service to our customers. OM&A reflects the transition to IFRS and will be higher than GAAP OM&A. This results primarily from the reclassification of disallowable costs otherwise included in capital which are charged to OM&A under IFRS, as well as processing costs for meter reads associated with Smart Metering, changes in work force demands and regulatory compliance requirements. Other drivers for the increase in 2011 include the inflationary impacts of cost inputs, the addition of six staff, additional preventative maintenance costs and requirements which may arise from the *Green Energy and Green Economy Act* (GEGEA).

IFRS OM&A per customer will increase due to the changes to IFRS OM&A and continued customer growth. As noted above the changes are driven mainly by increases in labour costs and anticipated economic adjustments to materials and supplies. Based on the latest information, Hydro One Brampton has one of the industry's lowest OM&A costs per customer, and Hydro One Brampton has the lowest costs in its peer grouping. Hydro One Brampton's OM&A cost was 24% lower than that of the average LDC in its respective peer group.

The most significant driver of the OM&A increase of $7.5 million from 2009 to the 2011 test year is the $3.1 million reclassification of disallowable costs resulting from the transition to IFRS. Under IFRS these expenses are not considered directly attributable to capital work and include costs such as engineering supervision and administration, training, vehicle maintenance and health safety and environment supervision and administration.In addition there are expected incremental costs in 2011 of $0.8 million associated with the MDMR processing of meter read data. There are planned staff additions over the two years including a new Asset Management department, costs related to GEGEA, and CDM costs, these combined with inflationary impacts of cost inputs account for $3.6 million.

OM&A costs in this Exhibit represent Hydro One Brampton's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to

comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to Hydro One Brampton's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

Hydro One Brampton is proposing recovery of 2011 Test Year OM&A costs, including amortization but excluding PILs and Interest totalling $25,306,728. A summary of Hydro One Brampton's operating costs for the 2006 Board Approved, 2006 to 2009 Actual, 2010 Bridge Year and the 2011 Test Year is provided below.

Table 1: Summary of Operating Costs

	2006 Board Approved	2006 Actuals	2007 Actuals	2008 Actuals	2009 Actuals	Bridge Year 2010	Test Year 2011
Operation	2,720,134	3,350,836	3,079,156	3,544,751	3,815,041	7,471,849	6,854,992
Maintenance	2,700,089	3,023,980	3,091,210	3,374,105	3,159,226	3,744,440	4,035,503
Billing and Collecting	3,512,796	3,775,564	3,820,263	4,324,468	4,897,921	4,632,782	5,656,663
Community Relations	256,376	1,018,450	797,999	371,587	363,138	570,000	640,000
Administrative and General	4,463,821	4,986,820	5,137,182	5,558,770	5,601,103	7,621,698	8,119,570
Total OM&A Expenses	13,653,216	16,155,651	15,925,811	17,173,680	17,836,429	24,040,769	25,306,728

Detailed information with respect to OM&A costs and variances, arranged by USoA account, is provided at Exhibit 4, Tab 3.

Hydro One Brampton, similar to many other LDCs, has found a need to increase headcount, specifically in the skilled trade areas, in order to address the aging workforce and the limited pool of skilled workers. To that effect, Hydro One Brampton has an increase from a level of 183 staff in 2006 Board Approved to 231 staff in 2011. This is a significant driver in the increase in OM&A costs. More detailed information is provided at Tab 2 of this Exhibit.

In addition to staffing changes, Hydro One Brampton has experienced increases in the costs of some contracted services (e.g. tree trimming), regulatory expenses and required programs.

Hydro One Brampton began development of the budget to support this forecast in late winter of 2009, with a presentation to the Board of Directors in the spring of 2010. The OM&A budgeting process is described in more detail at Exhibit 1, Tab 2, Schedule 2.0.

COST DRIVERS / SIGNIFICANT CHANGES

Cost driver analysis can be found in Exhibit 4, Tab 2, Schedule 1.3.

OVERALL COST TREND

Overall cost trend, financial and costing assumptions can be found in Budget Process Overview at Exhibit 1, Tab 2, Schedule 2.0.

INFLATION RATES USED

OVERVIEW

The electricity industry in Ontario is facing a period of significant change as a result of initiatives such as smart meters/time of use-billing, smart grid, distributed generation and the Green Energy Act. At the same time Hydro One Brampton has an aging asset base that requires maintenance and/or replacement of assets in order to maintain system reliability.

The need to replace aging assets, time of use billing, Green Energy Act initiatives, the new HST tax and higher cost of power for green energy sources (e.g. - wind and solar) are all placing upward pressure on customer rates. Although some of these cost drivers are outside our control, Hydro One Brampton must balance the need to maintain reliable power with customer's expectations of reasonable rates, where possible.

It is recognized that there are situations where costs will increase. Increased costs will result from incremental work that supports innovation, drives productivity, or results from new requirements/regulations, such as:

- Green Energy Act
- PCB legislation
- OEB Policy
- Government Policy

Since the results of our business planning process form the basis of future OEB rate applications, it is important that all costs are necessary and supportable.

ECONOMICS

Table 1: CPI Ontario

	2010	2011	2012	2013	2014	2015
CPI – Ontario (%)	1.9	2.1	2.0	2.1	2.0	2.1
Dx cost escalation for Construction (%)	0.0	1.5	2.1	2.6	2.7	2.5
Dx cost escalation for Operations & Maintenance (%)	1.3	2.3	2.4	2.3	2.1	2.2
Exchange Rate (CDN$/US$)	1.044	1.054	1.055	1.073	1.086	1.123

CPI-Ontario was based on the IHS Global Insight April 2010 forecast and US cost escalators forecasts were based on the Global Insight February 2010 forecast.

The exchange rate forecasts for 2010, 2011, 2012 are based on the March 2010 Consensus Forecast while the 2013, 2014, 2015 exchange rate forecasts are based on February 2010 Global Insight.

STAFFING

Despite the Company's efforts to date to maintain an adequate supply of labour, HOBNI continues to face staffing challenges. 41% of employees are currently 50 years of age or older; at the end of the test year, 12% of Hydro One Brampton's current staff will be eligible for an undiscounted retirement. By 2011, Hydro One Brampton's staffing count will be forecasted at 231 which represent a 26% increase since the OEB approved rebasing year (2006).

Of the seven new positions added in the test year, three were added due to increased workload from projects and new initiatives. Two new positions were added for succession planning and the remaining two position additions were a result of a combination of both increased workload and succession planning. One position will be eliminated due to the completion of a program.

In an environment which will continue to endure increased customer growth, regulatory change, technological advances and budget constraints, and an industry that has aging demographics and a highly competitive labour market, Hydro One Brampton needs to be positioned as an attractive employer in order to succeed in recruiting and retaining staff with the appropriate skills. To do so, the Company must provide a competitive compensation package and challenging and rewarding job opportunities.

BUSINESS ENVIRONMENT CHANGES

Business environment changes can be found in Budget Process Overview at Exhibit 1, Tab 2, Schedule 2.0.

MATERIALITY THRESHOLDS AND OTHER ASSUMPTIONS

The variance threshold used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million. Hydro One Brampton has based the threshold calculation on the proposed revenue requirement and adopted a variance analysis threshold of $300,000 throughout this analysis.

EXHIBIT 4 TAB 2

SUMMARY AND COST DRIVER TABLES

OVERVIEW - DESCRIPTION OF OM&A EXPENSES

Below is a description of the nature of costs included in each cost category for Hydro One Brampton along with a breakdown of the departments responsible for the costs, and an explanation on how costs are determined.

OPERATIONS & MAINTENANCE

As described in the Filing Guidelines, the Distribution Expenses – Operations and Distribution Expenses – Maintenance cost category includes the following accounts:

Distribution Expenses – Operation

- 5005 Operation Supervision and Engineering
- 5010 Load Dispatching
- 5012 Station Buildings and Fixtures Expense
- 5014 Transformer Station Equipment – Operation Labour
- 5015 Transformer Station Equipment – Operation Supplies and Expenses
- 5016 Distribution Station Equipment – Operation Labour
- 5017 Distribution Station Equipment – Operation Supplies and Expenses
- 5020 Overhead Distribution Lines and Feeders – Operation Labour
- 5025 Overhead Distribution Lines and Feeders – Operation Supplies and Expenses
- 5030 Overhead Sub-transmission Feeders – Operation
- 5035 Overhead Distribution Transformers – Operation
- 5040 Underground Distribution Lines and Feeders – Operation Labour
- 5045 Underground Distribution Lines and Feeders – Operation Supplies and Expenses
- 5050 Underground Sub-transmission Feeders – Operation
- 5055 Underground Distribution Transformers – Operation
- 5060 Street Lighting and Signal System Expense
- 5065 Meter Expense
- 5070 Customer Premises – Operation Labour

- 5075 Customer Premises – Materials and Expenses
- 5085 Miscellaneous Distribution Expense
- 5090 Underground Distribution Lines and Feeders – Rental Paid
- 5095 Overhead Distribution Lines and Feeders – Rental Paid
- 5096 Other Rent

Distribution Expenses – Maintenance

- 5105 Maintenance Supervision and Engineering
- 5110 Maintenance of Buildings and Fixtures – Distribution Stations
- 5112 Maintenance of Transformer Station Equipment
- 5114 Maintenance of Distribution Station Equipment
- 5120 Maintenance of Poles, Towers, and Fixtures
- 5125 Maintenance of Overhead Conductors and Devices
- 5130 Maintenance of Overhead Services
- 5135 Overhead Distribution Lines and Feeders – Right of Way
- 5145 Maintenance of Underground Conduit
- 5150 Maintenance of Underground Conductors and Devices
- 5155 Maintenance of Underground Services
- 5160 Maintenance of Line Transformers
- 5165 Maintenance of Street Lighting and Signal Systems
- 5170 Sentinel Lights – Labour
- 5172 Sentinel Lights – Materials and Expenses
- 5175 Maintenance of Meters
- 5178 Customer Installations Expenses – Leased Property
- 5195 Maintenance of Other Installations on Customer Premises

Within Hydro One Brampton, expenses related to these two cost categories include all costs relating to the operation and maintenance of Hydro One Brampton's electrical distribution system. This includes both direct labour costs and non-capital material spending to support both

scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering and Operations Supervision and Administration, Material Handling, Vehicle Burdens, and Building Maintenance & Administration.

Hydro One Brampton's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program (including predictive and preventative actions).

Hydro One Brampton's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with Hydro One Brampton's capital project work, so that where maintenance programs have identified problems, the correction of which require capital investments, the Company may adjust its capital spending priorities to address those matters. This process is described in more detail in conjunction with Hydro One Brampton's Asset Management Plan.

Below is a description of each of the departments involved directly in Operations & Maintenance of Hydro One Brampton's system, as well as a description of the indirect costs that are allocated.

Direct costs:	Control Room
	Meter Shop
	Stations
	Construction
Indirect costs:	Labour Burden
	Engineering Supervision and Administration
	Operations Supervision and Administration
	Material Handling
	Vehicle Burden
	Facility Maintenance
	Office Services

Control Room

Network operating costs are related to the 24-hour monitoring and operation of the distribution system through Hydro One Brampton's control room. The control room is staffed 24 hours a day, 7 days a week and is linked to the distribution system by a data communication network and information is processed by a Supervisory Control and Data Acquisition ("SCADA") system.

Real-time breaker status, and voltage and current readings from the Hydro One transformer stations and Hydro One Brampton substations, are sent to the control room and displayed on the SCADA system. The control room operators utilize an Outage Management System (OMS) to continuously monitor the system and assist with dispatching repair crews to manage equipment failures and provide work protection for the crews doing work on the system.

Metering

This department is responsible for the installation, testing, and commissioning of new and existing simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation and verifies meter multipliers for billing purposes. In addition, this department is also responsible for the installation testing, and commissioning of Smart Meters.

The Metering department is also involved in troubleshooting and resolving issues associated with trouble reports that involve failed meters along with various customer dispute investigations. Meter disconnections and reconnections are also performed by this department.

Substation Services

Substation services activities address the maintenance of all equipment at Hydro One Brampton owned and operated 230 kV transmission station (Jim Yarrow) and 15 municipal substations. This includes both labour costs and non-capital material spending to support both scheduled and emergency maintenance events. As with the maintenance activities, Hydro One Brampton's substation maintenance strategy focuses on minimizing, to the extent possible, emergency-type work by improving the effectiveness of Hydro One Brampton's planned maintenance program (including predictive and preventative actions) for its substations.

Construction

The Hydro One Brampton construction group is responsible for the field assets at the 4 kV / 13.8 kV / 27.6 kV / 44 kV levels, required for maintaining power to its 131,000 residential and business customers in the City of Brampton. This is accomplished through predictive and pro-active maintenance programs, equipment repair and expansion of its system to meet customer demand. The field assets include approximately 13,500 poles, 2,231 km of 3 phase, 2 phase and 1 phase overhead and 2,926 km of underground lines, as well as 15,610 transformers. Duties also include emergency and trouble call response 24 hours/day, 365 days/year.

Engineering

The Engineering department includes the Planning & Standards, Capital Engineering, Development Engineering, Technical Services and Asset Management departments. Planning and Standards is responsible for setting planning criteria and plant performance standards to meet system needs, and for preparing development plans to cater for future load growth and new connections. The need for System Expansion and Reinforcement is identified through system planning studies and load flow analysis. This may include the construction of new feeder or sections of feeders, equipment or conductor upgrade on existing feeders, and increase in capacity at a station upstream of the new feeders and upgrades.

Planning & Standards also has the responsibility for HOBNI's compliance with ESA Regulation #22/04, which includes approved; standard framing designs, materials, and construction designs, which are required for the construction and energization of projects as per Hydro One Brampton's Construction Verification Program. Capital Engineering is responsible for providing services in the area of design, cost estimating and project management for new asset installations and planned asset replacement projects arising from approved capital project recommendations to replace assets according to asset renewal programs. Development Engineering produces design standards and guidelines for subdivision and townhouse developments. Development Engineering also has the responsibility to produces designs and estimates for the relocation of Hydro One Brampton plant as required through requests from the road authorities. The Technical Services department handles service inquiries from customers and developers for industrial/commercial, high density residential and generator type connections.

Asset Management is responsible for the management of processes and documentation relevant to asset management. The group maintains an asset management database for recording assets and asset management activities. The recorded information contains details of location and plant fitted to that location, asset standard type nominations, standard maintenance levels, required maintenance and testing activities, frequencies (trigger dates), standard job templates and their cost, maintenance history and repair activities, outstanding maintenance work with its cost and planned future schedules. The asset management group provides detailed analysis and review of asset performance, the required time frame for action, and recommendations on required action. To help justify projects, the asset management group prepares a detailed technical and financial business case for each particular asset project.

Engineering costs are applied as a percentage of direct labour dollars for Operations, Maintenance, Capital, and Third Party receivable accounts.

Operations

The Operations department includes Drafting & Records, GIS/Operations, Survey, Locates & Inspections, Substations and Protection & Control departments. The GIS department is responsible for keeping up-to-date asset related data on HOBNI's Geographic Information System (GIS). This data is the basis of numerous applications within Hydro One Brampton, including up-to-date mapping in the Control Room used for all system switching, trouble shooting, load shifting, and emergency response. The Drafting & Records department delivers drafting services to the design technicians for capital and development projects and provides distribution system asset information to many departments within Hydro One Brampton. The Survey, Locates & Inspections department is responsible for layout services, locating services, obtaining permits for all construction projects carried out by HOBNI and its contractors. They are also responsible for easement and land rights negotiations and issuing joint use attachment permits including field inspection and approvals. The Operations department is in charge of the administration and development of the GIS, OMS and SCADA systems used in the Engineering & Operations and Lines departments. The Substation and Protection & Control and the Control Room departments were previously discussed.

Materials Handling

A percentage rate is calculated based on a periodic study using a three year average cost of operating the Purchasing & Stores Department, the last study was done in 2009. This percentage is then applied to the landed cost of the material that is issued from Stores and charged to a project. Projects may be capital, operating, maintenance, or third party billable projects.

This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. A standard overhead percentage is set at the beginning of the year.

Hydro One Brampton maintains a Purchasing and Stores Department. Purchasing & Stores staff are accountable for managing the procurement, control, and movement of materials within Hydro One Brampton's service centre. The cost of maintaining this department is collated and allocated as a fixed standard material surcharge rate of 15%, which is applied on top of the cost of materials requested from the Company's stores and those directly shipped to the job.

At a high level, the cost elements embedded in the material surcharge rate include:

- The labour and support expenses to sustain the internal procurement department.
- Warehouse costs, specifically the cost of labour and expenses for the store-keepers that manage the warehouse, as well as overheads of the physical warehouse location.
- The labour costs for employees that perform required inspections/testing of materials during and after their purchase.
- Depreciation of equipment used in the warehouse

Vehicle Burden

Hydro One Brampton owns and operates in excess of 100 vehicles and other fleet equipment to support its capital work programs. The Fleet department provides centralized and turnkey services that include maintenance, administration, vehicle replacement and disposal. An hourly rate per vehicle class is calculated periodically through a study using five year average costs based on the cost of maintaining the fleet. The last study was conducted in 2008. This rate is then charged to all projects based on the number of hours the vehicle is used on that project.

Like labour rates, vehicle and equipment rates are “fully loaded” to ensure that all costs required to deploy equipment are accurately and cost effectively distributed to the benefiting capital (and OM&A) project.

At a high level, the costs elements embedded in the standard vehicle rates include:

- *Operations and Repair Costs* **-** This cost category primarily consists of repair costs (labour and parts) related to the maintenance of fleet equipment. Operations cost includes wages, materials and contractor costs.
- *Depreciation* **-** The depreciation expense for each vehicle is calculated based on the current Hydro One Brampton depreciation rates.
- *Fuel Cost* **-** Fuel costs are charged directly to the particular piece of equipment consuming the fuel. These then form part of the costs of the fleet department, which are allocated to the individuals capital (and OM&A) projects and programs via the method described above.

Indirect Labour and Payroll Burden Costs:

Trade labour hours are distributed directly to benefiting programs and projects by the use of timesheets, consistent with common industry practice. Labour rates are "fully loaded" to ensure that all associated support costs required to deploy resources are accurately and cost effectively distributed to the benefiting work.

At a high level, the cost elements embedded in the overhead rates include:

- *Payroll Obligations* – base pay, contractually negotiated payroll allowances, government obligations paid by Hydro One Brampton (e.g. CPP and EI benefits) and Company benefits.
- *Contractual Time Away from Work* – employee vacation, statutory holidays, banked time and time taken due to sickness.
- *Time not Directly Benefiting a Specific Program or Project* – time for attendance at safety meetings, time used to complete the required health and safety training, and housekeeping and downtime, the latter most often created due to inclement weather.
- *Field Supervision and Technical Support* – costs associated with field trades supervision and other management and technical staff providing support to manage and monitor the status of the assigned programs and projects.
- *Support Activities* – administrative expenses, costs for centralized support activities and work management systems and costs to design, develop and deliver work method training and health and environmental practices.

Hydro One Brampton uses three different overhead labour rates depending on the nature of the project

Facility Maintenance

The costs of maintaining the administration office, grounds and other structures at 175 Sandalwood Parkway are allocated to operations based on a percentage of square footage of various departments.

Office Services

The costs of office administration including postage, telephone and office services at 175 Sandalwood Parkway are allocated to operations based on a percentage of square footage of various departments.

BILLING AND COLLECTING

Within Hydro One Brampton, the costs included in the Billing and Collecting cost category, accounts listed below, are related to two departments within the organization, the Billing and Meter Reading department and the Customer Service department. Descriptions of these departments and their activities are included below the account listing.

Billing and Collecting Account Listing

- 5305 Supervision
- 5310 Meter Reading Expense
- 5315 Customer Billing
- 5320 Collecting
- 5325 Collecting – Cash Over and Short
- 5330 Collection Charges
- 5335 Bad Debt Expense
- 5340 Miscellaneous Customer Accounts Expenses

Customer Accounts Department Functions:

The Customer Service group is responsible for the customer call centre, meter reading and billing activities for the approximately 131,000 customers in Hydro One Brampton's service area. Hydro One Brampton aspires to achieve customer service excellence in its processes and customer programs.

Customer Call Centre:

The Customer Call Centre is responsible for such activities as payment processing; move in and out requests; and call centre activities for Hydro One Brampton's service territory. On average call volumes continue to increase annually. Hydro One Brampton's customer service department handles over 143,000 inquires per year. With time-of-use billing and smart meter installations, Hydro One Brampton anticipates an increase in call volume activity.

Metering Reading:

Meter reading services are primarily contracted out to a non-affiliated third party under a service contract agreement. On average the contractor reads 20,000 electric service meters per month. The meter contract was negotiated after the completion of a competitive bid process. This contract was in place until June 30, 2009 after which it was extended for a year. The contracted

meter reading will cease to exist once all meters have been converted to Smart Meters, which is anticipated to be completed by December 31, 2011.

Hydro One Brampton is actively installing smart meters to residents and small businesses in the City of Brampton. As part of this installation, the ability to remotely read meters is underway. Hydro One Brampton is currently working with the IESO on the transition to the MDMR for storage of meter reading data, and reviewing our CIS system to allow for billing customers based on automated readings. Once the installation of smart meters has been completed and integrated with the provincial MDMR, it is anticipated that Hydro One Brampton will apply to the OEB for a smart meter rate rider which will include final and audited capital costs, plus OM&A costs and potential savings reflecting actual smart meter communication costs.

Billing

Hydro One Brampton issues approximately 1,560,000 invoices annually to customers. An additional 15,000 final bills are prepared for customers moving within or outside of Hydro One Brampton's service territory. An annual billing schedule is created based on the meter reading schedule to ensure timely billing of services. The billing functions include the VEE processes; EBT and retailer settlement functions for approximately 26,500 retailer accounts; account adjustments; processing meter changes; and other various account related field service orders and mailing services. Hydro One Brampton offers customers a number of billing and payment options including an equal payment plan, direct deposit, electronic billing and a preauthorized payment plan.

Collections Department

Collections involve a combination of activities, including the collection of overdue active accounts, security deposits and final bills for service termination. Credit risk is a concern for Hydro One Brampton with a bad debt expense forecast of $400,000 in 2010, based on bad debt experienced in 2009. In an effort to minimize credit losses, Hydro One Brampton enforces a prudent credit policy in accordance with the Distribution System Code. Active overdue accounts are collected by in-house staff through notices, letters and direct telephone contact. Final bill collections are turned over to a collection agency 30 days after the final due date.

ENERGY SERVICES / COMMUNITY RELATIONS

Hydro One Brampton is committed to providing consumer information and responses, in a timely and proactive manner, on electricity distribution and related issues. Hydro One Brampton's Energy Services department maintains a presence in the community, and staff are available to answer customer questions in an environment outside of the main office building.

Since LDCs are the "face-to-the-customer" for the electricity industry, Hydro One Brampton's Energy Services department has an important role to play in educating the public about electricity safety and energy conservation.

Within Hydro One Brampton, the costs included in the Community Relations cost category are related to the functions of the Hydro One Brampton community safety programs and the conservation initiatives that are not funded by the OPA. Descriptions of these activities are included below the account listing. Hydro One Brampton does not have any sales related expenditures. Revenue Protection is another key activity performed by Energy Services, by proactively investigating potential diversion and theft of power.

Community Relations (including sales expenses)

- 5405 Supervision
- 5410 Community Relations – Sundry
- 5415 Energy Conservation
- 5420 Community Safety Program
- 5425 Miscellaneous Customer Service and Informational Expenses
- 5505 Supervision
- 5510 Demonstrating and Selling Expense
- 5515 Advertising Expense
- 5520 Miscellaneous Sales Expense

Education – Electricity Safety

Hydro One Brampton supports electrical safety education in the community through a number of various channels including:

- Elementary School Safety: Hydro One Brampton visits local school providing age appropriate sessions on electricity safety and conservation for students in grades four and five. This program is offered to all Brampton schools every year.
- Secondary School Safety: Hydro One Brampton participates in "Take your Child to Work" day, where staff's sons and daughters who are in grade 9 are invited to Hydro One Brampton to learn aspects of work in the LDC, including workplace and electrical safety.
- General Safety: Hydro One Brampton has worked at various civic events, distributing literature with respect to general electrical safety within the home and at the workplace.

Energy Conservation

Building a conservation culture in Brampton continues to be an important objective for Hydro One Brampton. Hydro One Brampton is very active in the community promoting conservation initiatives, attending a number of community events each year and distributing information on energy conservation. Hydro One Brampton continues to participate with the OPA in administering programs directed at energy conservation such as The Great Refrigerator Roundup, Peaksaver, ERIP, Power Savings Blitz and the Multi-Family Energy Efficiency Retrofit. In a number of programs, Hydro One Brampton has exceeded the OPA's targets for several consecutive years.

ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include expenses incurred in connection with the general administration of the utility's operations. Below is a listing of the USoA accounts included in this cost category, as well as a description of the activities and costs included in each.

Administrative and General Expenses

- 5605 Executive Salaries and Expenses
- 5610 Management Salaries and Expenses
- 5615 General Administrative Salaries and Expenses
- 5620 Office Supplies and Expenses

- 5625 Administrative Expense Transferred-Credit
- 5630 Outside Services Employed
- 5635 Property Insurance
- 5640 Injuries and Damages
- 5645 Employee Pensions and Benefits
- 5650 Franchise Requirements
- 5655 Regulatory Expenses
- 5660 General Advertising Expenses
- 5665 Miscellaneous General Expenses
- 5670 Rent
- 5675 Maintenance of General Plant
- 5680 Electrical Safety Authority Fees
- 5685 Independent Electricity System Operator Fees and Penalties
- 5695 OM&A Contra Account
- 6205 Charitable Donations

Within Hydro One Brampton, the following functional areas are considered to be part of general administration and, as such, expenses incurred within theses functional areas are accounted for as administrative and general expenses:

- Executive
- Human Resources
- Accounting
- Information Technology
- Regulatory Affairs

The functions of each of these groups are described in more detail on the following page.

Executive

The Executive group is responsible for the leadership and direction of Hydro One Brampton, in accordance with the Hydro One Brampton Mission Statement. The costs associated with this

group include the salaries, benefits, and miscellaneous costs of the President and CEO, Vice-President of Finance/Administration, and Vice-President of Engineering and Operations.

Human Resources

The Human Resources department is responsible for benefits administration, pension, health & safety, employee wellness, recruitment, labour relations, performance management and training and development of all staff. The department is made up of a Human Resources Representative and a Benefits Administrator.

Accounting

The Accounting department is responsible for the preparation of statutory, management and Board of Directors financial reporting in accordance with CGAAP; as well as for all daily accounting functions, including accounts payable, accounts receivable, and general accounting; accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance. Expenses include salaries and all related expenses associated with the Controller, Accounting Supervisor, Financial Analyst, Management Accountant, Payroll Administrator and four Accounting Clerks.

Information Services

The Information Services department is responsible for the development, operation, maintenance and security of all business system applications utilized by the utility in its operations. These include customer information, financial management and work management systems. Expenses include salaries and all related costs associated with the Customer Service & Information Technology Manager, Business Technology Supervisor, two Network Administrators and five Software Developers.

Regulatory Affairs

The Regulatory Affairs department is responsible for all regulatory reporting and compliance with applicable codes and legislation governing Hydro One Brampton. Regulatory reporting includes the development and preparation of rate filings, performance reporting, and compliance. This group is comprised of a Regulatory Affairs Manager, a Regulatory Affairs Supervisor, two Analysts, and one Communications Representative. Further details on regulatory costs are included at Exhibit 4, Tab 2, Schedule 3.0.

The Regulatory Affairs Manager is also responsible for the management and delivery of all energy conservation program initiatives through the Energy Services department. This department consists of an Energy Services Supervisor, two Energy Services Advisors and one Clerk.

SUMMARY OF OM&A EXPENSES

1 The following table provides Hydro One Brampton's summary of OM&A expenses for 2006 – 2011.

Table 1: OM&A Expenses 2006 – 2011

	2006 Board Approved	2006 Actuals	Variance 2006BA - 2006 Actuals	2007 Actuals	Variance 2007 - 2006 Actuals	2008 Actuals	Variance 2008 - 2007 Actuals	2009 Actuals	Variance 2009 - 2008 Actuals	Bridge Year (BY) 2010	Variance BY 2010 - 2009 Actuals	Test Year (TY) 2011	Variance TY - BY
Operation	2,720,134	3,350,836	630,702	3,079,156	(271,680)	3,544,751	465,594	3,815,041	270,290	7,471,849	3,656,808	6,854,992	(616,857)
Maintenance	2,700,089	3,023,980	323,891	3,091,210	67,230	3,374,105	282,895	3,159,226	(214,879)	3,744,440	585,214	4,035,503	291,063
Billing and Collecting	3,512,796	3,775,564	262,768	3,820,263	44,699	4,324,468	504,205	4,897,921	573,454	4,632,782	(265,139)	5,656,663	1,023,881
Community Relations	256,376	1,018,450	762,075	797,999	(220,451)	371,587	(426,412)	363,138	(8,449)	570,000	206,862	640,000	70,000
Administrative and General	4,558,610	4,986,820	428,210	5,137,182	150,361	5,558,770	421,588	5,601,103	42,334	7,621,698	2,020,595	8,119,570	497,872
Total OM&A Expenses	13,748,005	16,155,651		15,925,811		17,173,680		17,836,429		24,040,769		25,306,728	
Variance from previous year			2,407,646		(229,840)		1,247,870		662,748		6,204,340		1,265,959
Percent change (year over year)			17.51%		-1.42%		7.84%		3.86%		34.78%		5.27%
Percent change: Test year vs Most Current Actuals		41.88%											
Average for 2006-2009		6.95%											
Compound Annual Growth Rate (for 2006 to 2009)		1.69%											

DETAILED ACCOUNT BY ACCOUNT OM&A EXPENSES AND VARIANCE ANALYSIS 2006 TO 2011

Table 1 below (and continuing on the following page) provides Hydro One Brampton's detail account by account OM&A expenses for 2006 – 2011.

Table 1: Detail Account by Account OM&A Expenses 2006 - 2011

		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Operation							
5005	Operation Supervision and Engineering	-	-	43,046	225,693	128,675	491,268
5010	Load Dispatching	1,406,760	1,355,602	1,475,965	1,451,220	1,637,255	1,665,079
5012	Station Buildings and Fixtures Expense	174,222	194,332	194,951	194,084	207,958	213,259
5014	Transformer Station Equipment - Operation Labour	39,141	14,255	18,338	17,868	24,239	24,969
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-
5016	Distribution Station Equipment - Operation Labour	69,558	70,355	75,977	70,820	89,412	90,930
5017	Distribution Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-
5020	Overhead Distribution Lines & Feeders - Operation Labour	93,447	106,073	90,240	112,317	1,279,859	1,106,570
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	45,196	47,231	44,740	73,928	165,243	188,254
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-
5035	Overhead Distribution Transformers - Operation	80,309	65,663	85,142	122,107	141,374	114,895
5040	Underground Distribution Lines and Feeders - Operation Labour	174,395	172,837	118,042	169,948	965,574	854,602
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	-	-	-	-	-	-
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-	-
5055	Underground Distribution Transformers - Operation	65,251	80,463	65,976	95,252	145,153	118,761
5065	Meter Expense	882,302	549,088	690,273	691,342	1,702,191	1,041,299
5070	Customer Premises - Operation Labour	261,975	335,001	542,538	493,862	798,160	768,647
5075	Customer Premises - Materials and Expenses	720	174	263	(449)	-	-
5085	Miscellaneous Distribution Expense	41,608	47,231	62,939	64,689	136,756	125,609
5090	UG Dist Lines & Fdrs - Rental	270	-	-	-	-	-
5095	Overhead Distribution Lines and Feeders - Rental Paid	15,681	40,851	36,320	32,361	50,000	50,850
Sub-Total		**3,350,836**	**3,079,156**	**3,544,751**	**3,815,041**	**7,471,849**	**6,854,992**

Table 2: Detail Account by Account OM&A Expenses 2006 - 2011 (continued)

		2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
Maintenance							
5105	Maintenance Supervision and Engineering	41,805	46,331	44,740	56,158	209,705	187,613
5110	Maintenance of Building and Fixtures - Distribution Station	5,782	4,868	3,494	861	4,100	4,170
5112	Maintenance of Transformer Station Equipment	78,634	64,215	125,495	73,793	144,307	112,531
5114	Maintenance of Distribution Station Equipment	145,226	151,646	173,279	104,500	155,494	160,019
5120	Maintenance of Poles, Towers and Fixtures	252,041	268,156	273,383	169,120	301,756	456,622
5125	Maintenanceof Overhead Conductors and Devices	530,994	472,690	409,579	483,471	493,344	539,003
5130	Maintenance of Overhead Services	198,931	169,838	167,242	153,708	194,887	198,230
5135	Overhead Distribution Lines and Feeders - Right of Way	196,221	201,699	125,409	249,969	218,739	222,534
5145	Maintenance of Underground Conduit	-	-	-	-	-	-
5150	Maintenance of Underground Conductors and Devices	925,401	1,010,881	1,069,442	1,047,644	1,273,475	1,313,717
5155	Maintenance of Underground Services	609,676	652,305	933,308	764,770	683,673	793,977
5160	Maintenance of Line Transformers	22,591	29,745	30,758	32,768	42,681	23,087
5175	Maintenance of Meters	16,676	18,836	17,976	22,463	22,279	24,000
Sub-Total		**3,023,980**	**3,091,210**	**3,374,105**	**3,159,226**	**3,744,440**	**4,035,503**
Billing and Collecting							
5305	Supervision	193,674	197,360	208,759	220,033	307,991	314,151
5310	Meter Reading Expense	732,331	789,200	861,230	683,555	242,752	1,091,363
5315	Customer Billing	1,775,757	1,844,625	1,954,115	2,081,509	2,328,453	2,447,720
5320	Collecting	539,546	600,226	698,449	772,456	1,027,587	1,082,799
5325	Collecting - Cash Over and Short	-	-	-	1	-	-
5330	Collection Charges	12,654	10,210	10,257	8,305	29,999	10,710
5335	Bad Debt Expense	338,941	236,040	427,936	967,834	515,004	525,300
5340	Miscellaneous Customer Accounts Expense	182,662	142,602	163,722	164,230	180,996	184,620
Sub-Total		**3,775,564**	**3,820,263**	**4,324,468**	**4,897,921**	**4,632,782**	**5,656,663**
Community Relations							
5405	Supervision	13,508	107,468	106,257	93,878	125,000	115,000
5410	Community Relations - Sundry	199,391	123,644	207,522	211,285	275,000	255,000
5415	Energy Conservation	669,211	498,489	113	-	-	115,000
5420	Community Safety Program	-	-	-	-	25,000	25,000
5425	Misc Customer Service and Informational Expenses	136,340	68,398	57,695	57,975	145,000	130,000
Sub-Total		**1,018,450**	**797,999**	**371,587**	**363,138**	**570,000**	**640,000**
Administrative and General							
5605	Executive Salaries and Expenses	442,941	456,231	606,190	704,355	915,486	942,233
5610	Management Salaries and Expenses	1,165,817	1,156,092	1,136,222	1,165,341	2,206,651	2,062,994
5615	General Administrative Salaries and Expenses	1,006,434	1,048,214	1,137,685	1,124,107	1,392,760	1,548,279
5620	Office Supplies and Expenses	182,263	13,001	-	-	-	-
5625	Administrative Expense Transferred Credit	-	-	-	-	-	-
5630	Outside Services Employed	142,112	161,053	125,935	117,154	200,004	248,500
5635	Property Insurance	(2,533)	(232,326)	-	-	-	-
5640	Injuries and Damages	190,551	177,331	129,374	129,463	188,700	188,700
5645	Employee Pensions and Benefits	(194,909)	-	-	-	-	-
5655	Regulatory Expenses	696,401	825,573	812,294	838,051	945,000	1,045,000
5660	General Advertising Expenses	13,142	828	5,448	8,765	10,000	15,000
5665	Miscellaneous General Expenses	945,520	992,953	1,046,155	895,745	1,144,885	1,438,462
5670	Rent	-	-	-	-	-	-
5675	Maintenance of General Plant	415,617	475,028	450,855	561,626	557,012	568,152
5680	Electrical Safety Authority Fees	46,710	51,102	54,238	56,497	61,200	62,250
5685	IMO Fees & Penalties	2,278	-	-	-	-	-
5695	OM&A Contra Account	(65,527)	12,101	54,373	-	-	-
6215	Penalties	-	-	-	-	-	-
Sub-Total		**4,986,820**	**5,137,182**	**5,558,770**	**5,601,103**	**7,621,698**	**8,119,570**
Total OM&A Expenses		**16,155,651**	**15,925,811**	**17,173,680**	**17,836,429**	**24,040,769**	**25,306,728**

Hydro One Brampton has provided a detailed OM&A cost table covering the periods from 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Actual, 2010 Bridge Year and 2011 Test Year including the variances year over year in Table 3.

Table 3: OM&A Expenses by Account 2006 – 2011

		2006 Board Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge Year	Variance	2011 Test Year	Variance
Operation														
5005	Operation Supervision and Engineering	-	-	-	-	-	43,046	43,046	225,693	182,647	128,675	(97,018)	491,268	362,593
5010	Load Dispatching	1,082,800	1,406,760	323,961	1,355,602	(51,159)	1,475,965	120,363	1,451,220	(24,745)	1,637,255	186,035	1,665,079	27,824
5012	Station Buildings and Fixtures Expense	229,890	174,222	(55,668)	194,332	20,110	194,951	619	194,084	(867)	207,958	13,874	213,259	5,301
5014	Transformer Station Equipment - Operation Labour	29,120	39,141	10,021	14,255	(24,887)	18,338	4,084	17,868	(470)	24,239	6,371	24,969	730
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5016	Distribution Station Equipment - Operation Labour	87,233	69,558	(17,675)	70,355	797	75,977	5,622	70,820	(5,158)	89,412	18,592	90,930	1,518
5017	Distribution Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5020	Overhead Distribution Lines & Feeders - Operation Labour	79,617	93,447	13,830	106,073	12,626	90,240	(15,834)	112,317	22,077	1,279,859	1,167,542	1,106,570	(173,289)
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	85,236	45,196	(40,039)	47,231	2,035	44,740	(2,491)	73,928	29,188	165,243	91,315	188,254	23,011
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-	-
5035	Overhead Distribution Transformers - Operation	70,616	80,309	9,693	65,663	(14,647)	85,142	19,480	122,107	36,965	141,374	19,267	114,895	(26,479)
5040	Underground Distribution Lines and Feeders - Operation Labour	127,015	174,395	47,380	172,837	(1,558)	118,042	(54,795)	169,948	51,906	965,574	795,626	854,602	(110,972)
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	1,452	-	(1,452)	-	-	-	-	-	-	-	-	-	-
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-	-
5055	Underground Distribution Transformers - Operation	83,946	65,251	(18,695)	80,463	15,212	65,976	(14,487)	95,252	29,276	145,153	49,901	118,761	(26,392)
5065	Meter Expense	588,498	882,302	293,804	549,088	(333,214)	690,273	141,185	691,342	1,069	1,702,191	1,010,849	1,041,299	(660,892)
5070	Customer Premises - Operation Labour	185,442	261,975	76,533	335,001	73,025	542,538	207,538	493,862	(48,677)	798,160	304,298	768,647	(29,513)
5075	Customer Premises - Materials and Expenses	900	720	(180)	174	(546)	263	89	(449)	(712)	-	449	-	-
5085	Miscellaneous Distribution Expense	35,316	41,608	6,292	47,231	5,623	62,939	15,708	64,689	1,750	136,756	72,067	125,609	(11,147)
5090	UG Dist Lines & Fdrs - Rental	-	270	270	-	(270)	-	-	-	-	-	-	-	-
5095	Overhead Distribution Lines and Feeders - Rental Paid	33,055	15,681	(17,374)	40,851	25,171	36,320	(4,531)	32,361	(3,959)	50,000	17,639	50,850	850
Sub-Total		**2,720,134**	**3,350,836**	**630,702**	**3,079,156**	**(271,680)**	**3,544,751**	**465,594**	**3,815,041**	**270,290**	**7,471,849**	**3,656,808**	**6,854,992**	**(616,857)**
Maintenance														
5105	Maintenance Supervision and Engineering	35,000	41,805	6,805	46,331	4,526	44,740	(1,591)	56,158	11,418	209,705	153,547	187,613	(22,092)
5110	Maintenance of Building and Fixtures - Distribution Station	3,796	5,782	1,986	4,868	(914)	3,494	(1,374)	861	(2,633)	4,100	3,239	4,170	70
5112	Maintenance of Transformer Station Equipment	102,191	78,634	(23,558)	64,215	(14,419)	125,495	61,280	73,793	(51,701)	144,307	70,514	112,531	(31,776)
5114	Maintenance of Distribution Station Equipment	91,418	145,226	53,808	151,646	6,420	173,279	21,633	104,500	(68,780)	155,494	50,994	160,019	4,525
5120	Maintenance of Poles, Towers and Fixtures	202,388	252,041	49,652	268,156	16,115	273,383	5,227	169,120	(104,263)	301,756	132,636	456,622	154,866
5125	Maintenanceof Overhead Conductors and Devices	499,035	530,994	31,960	472,690	(58,304)	409,579	(63,112)	483,471	73,893	493,344	9,873	539,003	45,659
5130	Maintenance of Overhead Services	145,464	198,931	53,468	169,838	(29,093)	167,242	(2,596)	153,708	(13,534)	194,887	41,179	198,230	3,343
5135	Overhead Distribution Lines and Feeders - Right of Way	171,733	196,221	24,488	201,699	5,477	125,409	(76,290)	249,969	124,560	218,739	(31,230)	222,534	3,795
5145	Maintenance of Underground Conduit	-	-	-	-	-	-	-	-	-	-	-	-	-
5150	Maintenance of Underground Conductors and Devices	763,797	925,401	161,604	1,010,881	85,480	1,069,442	58,561	1,047,644	(21,798)	1,273,475	225,831	1,313,717	40,242
5155	Maintenance of Underground Services	664,557	609,676	(54,881)	652,305	42,629	933,308	281,003	764,770	(168,538)	683,673	(81,097)	793,977	110,304
5160	Maintenance of Line Transformers	13,210	22,591	9,381	29,745	7,154	30,758	1,013	32,768	2,010	42,681	9,913	23,087	(19,594)
5175	Maintenance of Meters	7,500	16,676	9,176	18,836	2,160	17,976	(860)	22,463	4,487	22,279	(184)	24,000	1,721
Sub-Total		**2,700,089**	**3,023,980**	**323,891**	**3,091,210**	**67,230**	**3,374,105**	**282,895**	**3,159,226**	**(214,879)**	**3,744,440**	**585,214**	**4,035,503**	**291,063**

Table 3: OM&A Expenses by Account 2006 – 2011 (continued)

		2006 Board Approved	2006 Actual	Variance	2007 Actual	Variance	2008 Actual	Variance	2009 Actual	Variance	2010 Bridge Year	Variance	2011 Test Year	Variance
Billing and Collecting														
5305	Supervision	167,428	193,674	26,246	197,360	3,685	208,759	11,399	220,033	11,274	307,991	87,958	314,151	6,160
5310	Meter Reading Expense	630,755	732,331	101,575	789,200	56,870	861,230	72,030	683,555	(177,675)	242,752	(440,803)	1,091,363	848,611
5315	Customer Billing	1,690,076	1,775,757	85,681	1,844,625	68,868	1,954,115	109,490	2,081,509	127,394	2,328,453	246,944	2,447,720	119,267
5320	Collecting	388,216	539,546	151,330	600,226	60,680	698,449	98,224	772,456	74,006	1,027,587	255,131	1,082,799	55,212
5325	Collecting - Cash Over and Short	-	-	-	-	-	-	-	1	1	-	(1)	-	-
5330	Collection Charges	12,858	12,654	(204)	10,210	(2,444)	10,257	47	8,305	(1,953)	29,999	21,694	10,710	(19,289)
5335	Bad Debt Expense	489,550	338,941	(150,609)	236,040	(102,901)	427,936	191,895	967,834	539,898	515,004	(452,830)	525,300	10,296
5340	Miscellaneous Customer Accounts Expense	133,913	182,662	48,748	142,602	(40,060)	163,722	21,120	164,230	508	180,996	16,766	184,620	3,624
Sub-Total		**3,512,796**	**3,775,564**	**262,768**	**3,820,263**	**44,699**	**4,324,468**	**504,205**	**4,897,921**	**573,454**	**4,632,782**	**(265,139)**	**5,656,663**	**1,023,881**
Community Relations														
5405	Supervision	57,088	13,508	(43,580)	107,468	93,960	106,257	(1,211)	93,878	(12,380)	125,000	31,122	115,000	(10,000)
5410	Community Relations - Sundry	96,222	199,391	103,169	123,644	(75,747)	207,522	83,878	211,285	3,763	275,000	63,715	255,000	(20,000)
5415	Energy Conservation	3,393	669,211	665,817	498,489	(170,721)	113	(498,377)	-	(113)	-	-	115,000	115,000
5420	Community Safety Program	-	-	-	-	-	-	-	-	-	25,000	25,000	25,000	-
5425	Misc Customer Service and Informational Expenses	99,673	136,340	36,668	68,398	(67,943)	57,695	(10,703)	57,975	280	145,000	87,025	130,000	(15,000)
Sub-Total		**256,376**	**1,018,450**	**762,075**	**797,999**	**(220,451)**	**371,587**	**(426,412)**	**363,138**	**(8,449)**	**570,000**	**206,862**	**640,000**	**70,000**
Administrative and General														
5605	Executive Salaries and Expenses	415,836	442,941	27,105	456,231	13,290	606,190	149,958	704,355	98,165	915,486	211,131	942,233	26,747
5610	Management Salaries and Expenses	550,749	1,165,817	615,069	1,156,092	(9,725)	1,136,222	(19,870)	1,165,341	29,119	2,206,651	1,041,310	2,062,994	(143,657)
5615	General Administrative Salaries and Expenses	1,339,746	1,006,434	(333,312)	1,048,214	41,779	1,137,685	89,472	1,124,107	(13,578)	1,392,760	268,653	1,548,279	155,519
5620	Office Supplies and Expenses	162,461	182,263	19,803	13,001	(169,262)	-	(13,001)	-	-	-	-	-	-
5625	Administrative Expense Transferred Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
5630	Outside Services Employed	(24,913)	142,112	167,025	161,053	18,941	125,935	(35,118)	117,154	(8,781)	200,004	82,850	248,500	48,496
5635	Property Insurance	1,332	(2,533)	(3,864)	(232,326)	(229,794)	-	232,326	-	-	-	-	-	-
5640	Injuries and Damages	482,828	190,551	(292,276)	177,331	(13,220)	129,374	(47,957)	129,463	88	188,700	59,237	188,700	-
5645	Employee Pensions and Benefits	39,637	(194,909)	(234,546)	-	194,909	-	-	-	-	-	-	-	-
5655	Regulatory Expenses	545,564	696,401	150,837	825,573	129,172	812,294	(13,279)	838,051	25,757	945,000	106,949	1,045,000	100,000
5660	General Advertising Expenses	7,843	13,142	5,299	828	(12,315)	5,448	4,621	8,765	3,317	10,000	1,235	15,000	5,000
5665	Miscellaneous General Expenses	667,207	945,520	278,313	992,953	47,433	1,046,155	53,202	895,745	(150,410)	1,144,885	249,140	1,438,462	293,577
5670	Rent	-	-	-	-	-	-	-	-	-	-	-	-	-
5675	Maintenance of General Plant	370,033	415,617	45,584	475,028	59,411	450,855	(24,173)	561,626	110,771	557,012	(4,614)	568,152	11,140
5680	Electrical Safety Authority Fees	-	46,710	46,710	51,102	4,392	54,238	3,136	56,497	2,259	61,200	4,703	62,250	1,050
5685	IMO Fees & Penalties	-	2,278	2,278	-	(2,278)	-	-	-	-	-	-	-	-
5695	OM&A Contra Account	-	(65,527)	(65,527)	12,101	77,628	54,373	42,272	-	(54,373)	-	-	-	-
6215	Penalties	289	-	(289)	-	-	-	-	-	-	-	-	-	-
Sub-Total		**4,558,610**	**4,986,820**	**428,211**	**5,137,182**	**150,361**	**5,558,770**	**421,588**	**5,601,103**	**42,334**	**7,621,698**	**2,020,595**	**8,119,570**	**497,872**
Total OM&A Expenses		**13,748,005**	**16,155,651**	**2,407,646**	**15,925,811**	**(229,840)**	**17,173,680**	**1,247,870**	**17,836,429**	**662,748**	**24,040,769**	**6,204,340**	**25,306,728**	**1,265,959**

VARIANCE ANALYSIS ON DETAIL OM&A COSTS

Hydro One Brampton has provided a detailed OM&A cost table covering the periods from 2006 Board Approved, 2006 to 2009 Actual, 2010 Bridge Year and 2011 Test Year including the variances year over year in Exhibit 4-3-1.1. A variance analysis for each account that exceeds the materiality threshold of $300,000 is provided below.

2006 ACTUAL VERSUS 2006 BOARD APPROVED

5010 – Load Dispatching

Load dispatching increased by $323,961 due to an increase in dispatcher response to major storms ($127,292) and an increase in overhead allocations.

5415 – Energy Conservation

In 2006, Hydro One Brampton spent $665,817 due to an increase in conservation and demand management initiatives, as approved under the Hydro One Brampton Conservation and Demand Management Plan (RP-2004-0203/EB-2005-0198).

5610 – Management Salaries and Expenses

Management salaries and expenses increased by $615,069 due to an increase in Hydro One Corporate charges on account of new Bill 198 requirements ($606,517).

5615 – General Administrative Salaries and Expenses

General Administrative Salaries and Expenses decreased by $333,312 due to an adjustment to 2004 Board Approved expenses in ED-2003-0038 (EB-2005-0008/RP-2005-0013).

5665 – Miscellaneous General Expenses

Miscellaneous General Expenses increased by $372,813 due mostly to the addition of an Accounting Supervisor ($107,000) and a Financial Analyst ($40,000).

2007 ACTUAL VERSUS 2006 ACTUAL

5065 - Meter Expense

Meter Expense decreased by $333,214 due to a reduced number of single phase meters that had to be reverified in 2007 as compared to 2006 ($83,000). There was also a decreased

number of failed meter bases and trouble reports associated with the three phase customers ($180,000). General maintenance of equipment was reduced by $53,000.

2008 ACTUAL VERSUS 2007 ACTUAL

5415 – Energy Conservation

Energy Conservation costs decreased by $498,377. In 2007, HOBNI was incurring costs associated with its Third Tranche conservation demand management (CDM) commitments, as approved under the Hydro One Brampton Conservation and Demand Management Plan (RP-2004-0203/EB-2005-0198). All programs and spending associated with Third Tranche were completed by the end of 2007.

2009 ACTUAL VERSUS 2008 ACTUAL

5335 – Bad Debt Expense

Bad debt expense increased by $539,898 due to the auto sector collapse, which saw three large bankruptcies in our service territory ($233,000), coupled with the write-off of amounts receivable from developers of $114,000 and an overall larger number of bankruptcies over 2008 due to the economic times.

2010 BRIDGE YEAR VERSUS 2009 ACTUAL

5020 – Overhead Distribution Lines & Feeders – Operation Labour

Overhead Distribution Lines & Feeders – Operation Labour show an increase of $1,167,542 due to $1,168,456 in non-directly attributable costs that have been moved from capital to OM&A under IFRS.

5040 – Underground Distribution Lines & Feeders – Operation Labour

Underground Distribution Lines & Feeders – Operation Labour show an increase of $795,626 due to $762,929 in non-directly attributable costs that have been moved from capital to OM&A under IFRS.

5065 - Meter Expense

Meter expense shows an increase of $1,010,849 from 2009 Actual, which is mainly associated with Hydro One Brampton's smart metering program. Throughout the implementation of this program, a decision was made to focus on installing meters on customers in the parts of the city that would present the least amount of failed meter bases and failed equipment. All questionable older areas, those areas that were expected to have a high failure rate, were saved for the last and will be completed in 2010 ($400,000). Hydro One Brampton will be expected to pay for software costs associated with the smart metering program once the program is completed ($320,000). In order to complete the commercial smart meter installations, Hydro One Brampton utilized its own metering crews to install these meters in 2009. As a result of this reallocation of metering crews to the smart metering project, the cross phase tests completed in 2009 were minimal. In 2010, it is expected that more cross phase testing will be done to meet our requirements, as compared to 2009 ($100,000).

5070 – Customer Premises – Operation Labour

Customer Premises – Operation Labour shows an increase of $304,298 due to $303,956 in non-directly attributable costs that have been moved from capital to OM&A under IFRS.

5310 Meter Reading Expense

Meter reading expense shows a decrease of $440,803, as Hydro One Brampton is expecting to utilize Smart Meter readings to replace the manual meter readings for billing purposes.

5335 – Bad Debt Expense

Bad Debt Expense shows a decrease of $452,830 from 2009 Actual. The one-time large bankruptcies from the auto sector in 2009 ($233,000) are not expected to re-occur, but the budget allowed for a 20% or $100,000 increase in bad debts from levels seen in 2008.

5610 – Management Salaries and Expenses

Management Salaries and Expenses show an increase of $1,041,310 due to $793,324 in non-directly attributable costs that have been moved from capital to OM&A under IFRS, as well as an increase of $221,000 in Hydro One Corporate charges on account of Finance charges related to IFRS implementation.

2011 TEST YEAR VERSUS 2010 BRIDGE YEAR

5005 – Operations Supervision and Engineering

Operations supervision and engineering shows an increase of $362,593 due to the implementation of an Asset Management Group in 2010. The increase is due to salaries for the additional staffing requirements of the group, including an Asset Management Supervisor, an Asset Maintenance Technician and a Financial Analyst.

5065 – Meter Expense

Meter expense shows a decrease of $660,893 due to the transfer of smart metering software cost responsibility from the metering department to the Information technology department ($300,000). Hydro One Brampton also expects a reduction of failed meter base costs, which will be offset by incremental smart metering maintenance costs ($285,000).

5310 - Meter Reading Expense

Meter Reading Expense shows an increase of $848,611 in 2011 as all smart meter reading costs previously deferred from smart metering variance account 1556 will be expensed in this account to incorporate all costs associated with the MDMR.

OM&A DRIVERS

Hydro One Brampton has reviewed the OM&A actual and forecasted information from 2006 to 2011 Test year and provides the following cost driver summary table, as well as written explanation of the drivers below. Table 4 identifies the key cost drivers from 2006 to 2011 Test year.

Table 1: Cost Drivers 2006 - 2011

G/L#	OM&A Cost Drivers	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
	Opening Balance	14,016,533	16,155,651	15,925,811	17,173,680	17,836,429	24,040,769
5645	OEB Reclassification (OMERS)	847,621	194,909	-	-	-	-
	Wages and Benefits	109,173	92,067	396,053	142,082	1,064,945	459,649
5415	Conservation and Demand Management	555,210	(170,721)	(498,377)	(113)	-	70,949
5335	Bad Debts	(251,895)	(102,901)	191,895	539,898	(452,830)	10,296
5315	Postage & Stationery	223,125	16,148	122,901	137,461	216,297	119,267
5310	Meter Reading	58,753	56,678	70,828	(179,032)	(441,975)	848,611
5135	Tree Clearing	71,428	9,151	(77,728)	123,485	(28,853)	3,795
5655	Regulatory Expenses	184,622	61,110	(10,313)	38,366	95,507	100,000
5010	Load Dispatching	163,775	(37,296)	9,445	2,982	95,536	27,824
5070	Consumer Premises	(539)	59,237	208,440	(66,655)	29,155	16,094
5610	Management Expenses	438,926	(9,725)	(19,870)	29,020	247,986	(24,625)
5615	General Administrative Salaries and Exper	(81,069)	26,428	68,125	(35,699)	246,065	155,519
5320	Collecting	65,960	42,483	89,852	58,025	244,167	55,212
5065	Meter Maintenance	160,349	(343,085)	107,384	(8,798)	853,859	(612,188)
5005/5020/5120/5150/5155	Line maintenance	(147,017)	93,117	346,480	(229,012)	200,568	683,938
5635	Property Insurance	(7,565)	(229,794)	232,326	-	-	-
	Disallowable Costs in Capital	-	-	-	-	3,647,467	(547,274)
	Other	(251,739)	12,354	10,428	110,739	186,446	(101,108)
	Closing Balance	16,155,651	15,925,811	17,173,680	17,836,429	24,040,769	25,306,728

2006 COST DRIVERS

OEB reclassification (OMERS).....$847,621

For all of 2005, the Company portion of OMERS premiums were charged to Account 1508, per instructions from the OEB. Commencing in May of 2006, the OMERS premiums were expensed in the OM&A costs. As there were no OMERS costs recorded in 2005, comparing 2005 to 2006 will result in a net increase in expenses of $847,621.

Wages and Benefits.....$109,173

In 2006, the hiring of new incremental personnel at a cost of $83,417, consisted of:

1. Smart Metering Project Coordinator (September 2006)
2. Financial Analyst (December 2006)

3. Journeyperson Operator (November 2006)
4. Information Technology Supervisor (December 2006)

The increase in wages of $122,594 was offset by a decrease in overtime costs of $60,519. Other decreases of $36,319 were for staff movements including retirements, promotions, resignations and terminations.

Conservation and Demand Management $555,210

Hydro One Brampton completed expenditures on conservation and demand management initiatives, as approved under the Hydro One Brampton Conservation and Demand Management Plan (RP-2004-0203/EB-2005-0198).

Bad Debts ..... ($251,895)

Bad debts decreased compared to 2005 due to additional effort and more timely collection calls for miscellaneous receivables from developers, which decreased developer bad debts by $193,000.

Postage and Stationery $223,125

In January of 2006, Canada Post applied an increase of $0.01 on regular mail, and $0.02 on pre-sorted mail. The $0.01 increase on regular mail affects our reminder notices, and the $0.02 on pre-sorted mail affects our customer bills.

Meter Reading $58,753

In 2006, the contractor costs associated with meter reading were higher by $60,624, reflecting a larger customer base.

Tree Clearing $71,428

Hydro One Brampton creates its work and maintenance plan based on three distinct geographical areas. In 2006, the tree clearing plan was for the largest geographical area.

Regulatory Expenses $184,622

Late in 2004, the OEB advised market participants that they were developing a new cost assessment model. In 2004 and 2005 incremental costs for OEB charges were included in variance account 1508. This amount in the deferral account was included in the 2006 EDR rate application, and were tracked in the regulatory account from May 2006 forward.

Load Dispatching $163,775

In 2006, the control room was assigned part of the allocations of facility maintenance and office services based on square footage.

Management Expenses $438,926

Corporate function and service charges from Hydro One increased from $361,244 in 2005 to $716,588 in 2006 due to Bill 198 compliance requirements.

Meter Maintenance..... $160,349

The variance was largely due to Measurement Canada's revised requirements which entailed reverification of an increased number of single phase meters. In addition in 2006 Measurement Canada also, required additional verification of three phase meters. This program, in addition to other maintenance work associated with these larger customers increased 2006 costs.

Line Maintenance ..... ($147,017)

Line maintenance expenses depend greatly on weather and the number of emergency repairs done mostly on weekends by contractors. Contractor expenses decreased by $127,000 as compared to 2005.

Other ..... ($266,849)

"Other" is the total of all other changes in costs included in Hydro One Brampton's OM&A costs, and is within the materiality threshold of $300,000.

2007 COST DRIVERS

OEB reclassification (OMERS) $194,909

Starting in May of 2006 the employer portion of OMERS premiums were expensed to OM&A. This variance is due to the OMERS premiums for the months of January to April 2007 that were recorded in expenses whereas the OMERS premiums for January to April 2006 were recorded in USoA account 1508. Comparing 2007 to 2006 will result in a net increase in expenses of $194,909.

Wages and Benefits $92,067

In 2007, the hiring of new incremental personnel at a cost of $93,941, consisted of:

1. GIS/Operations Analyst (February 2007)
2. Regulatory Affairs Administrator (June 2007)
3. Customer Accounts Representative – Billing (August 2007)
4. Meter Mechanic Apprentice (November 2007)

Wages increased by $126,380 and overtime decreased by $48,150. Other decreases of $80,104 were for staff movements including retirements, promotions, resignations and terminations.

Conservation and Demand Management ..... ($170,721)

Hydro One Brampton completed expenditures on conservation and demand management initiatives, as approved under the Hydro One Brampton Conservation and Demand Management Plan (RP-2004-0203/EB-2005-0198).

Bad Debts ..... ($102,901)

Bad debts decreased compared to 2006 due to additional effort and more timely collection calls for miscellaneous receivables from developers.

Postage & Stationery $16,148

The increase in postage costs is a typical increase resulting from customer growth.

Meter Reading $56,678

In 2007, the contractor costs associated with meter reading were higher, reflecting a larger customer base, more appointment reads and more movers.

Tree Clearing $9,151

Hydro One Brampton produces its work and maintenance plan based on three distinct geographical areas. In 2007, the tree clearing plan was for a similar-sized geographical area to the one in 2006.

Regulatory Expenses $61,110

The OEB assessment costs included in 2006 reflected only a partial year. The costs in 2007 reflect a full year of cost assessments.

Load Dispatching ..... ($37,296)

In 2007, load dispatching decreased due to variances in the allocations of facility maintenance and office services based on square footage.

Consumer Premises $59,237

As a result of the installation of smart meters, more repairs were required to damaged bases compared to 2006.

Management Expenses ..... ($9,725)

Management expenses were comparable to prior year.

Meter Maintenance ..... ($343,085)

The decrease in Meter Maintenance is due to a reduced number of single phase meters that had to be reverified in 2007 as compared to 2006 ($83,000). There was also a decreased number of failed meter bases and trouble reports associated with the three phase customers ($180,000). General maintenance of equipment decreased by $53,000.

Line Maintenance $93,117

The increase in Line Maintenance is due to increased underground primary maintenance due to weather and ageing equipment.

Property Insurance ..... ($229,794)

In 2007, the legal claims reserve was reduced by $229,794.

Other $81,265

“Other” is the total of all other changes in costs included in Hydro One Brampton’s OM&A costs, and is within the materiality threshold of $300,000.

2008 COST DRIVERS

Wages and benefits $396,053

In 2008, the hiring of new incremental personnel at a cost of $253,461, consisted of:

1. Meter Mechanic Apprentice (Jan 2008)
2. Retailer Support Representative (April 2008)
3. Vice-President of Engineering and Operations (April 2008)
4. Smart Meter Clerk (May 2008)

Wages increased by $137,540 and overtime increased by $133,725, this was offset by decreases of $128,673 for staff movements including retirements, promotions, resignations and terminations.

Conservation and Demand Management ..... ($498,377)

In 2007, Hydro One Brampton completed expenditures on third-tranche conservation and demand management initiatives, as approved under the Hydro One Brampton Conservation and Demand Management Plan (RP-2004-0203/EB-2005-0198). Therefore, 2008 costs were significantly below the previous year.

Bad Debts $191,895

During 2007, there were two bankruptcies totalling about $62,000 which contributed to this increase.

Postage & Stationery $122,901

The increase in postage costs is a typical increase resulting from customer growth.

Meter Reading $70,828

In 2008, the contractor costs associated with meter reading were higher by $59,966, reflecting a larger customer base, more appointment reads and more movers.

Tree Clearing ..... ($77,728)

Hydro One Brampton creates its work and maintenance plan based on three distinct geographical areas. In 2008, the tree clearing plan was for a smaller-sized geographical area than in prior years.

Regulatory Expenses..... ($10,313)

The OEB assessment costs were lower by $13,060 in 2008 compared to 2007.

Load Dispatching.....$9,445

In 2008, the costs were comparable to the previous year.

Consumer Premises $208,440

During 2008, there were a large number of free disconnect / reconnect services to Brampton customers due city residential service changes. As the result of the installation of smart meters, more repairs were required to damaged bases as compared to 2007.

Management Expenses ..... ($19,870)

There was a decrease in conference expenses from prior year.

Meter Maintenance.....$107,384

The increase in Meter Maintenance is due to an increase in the number of three phase meters that required re-verification as per Measurement Canada.

Line Maintenance.....$346,480

As there were a lot of freeze/thaws in the winter and spring, and the cables are getting close to 30 years old, the number of underground secondary faults doubled from 2007.

Property Insurance $232,326

In 2007, two large legal claims reserves were reversed.

Other.....$168,405

“Other” is the total of all other changes in costs included in Hydro One Brampton’s OM&A costs, and is within the materiality threshold of $300,000.

2009 COST DRIVERS

Wages and Benefits $142,082

In 2009, the hiring of new incremental personnel at a cost of $104,855, consisted of:

1. Line Apprentice (September 2009)
2. Heavy Duty Driver (March 2009)
3. Heavy Duty Driver (March 2009)
4. Regulatory Affairs Analyst (December 2009)
5. Credit & Collection Clerk (November 2009)

Wages increased by $145,948 and overtime decreased by $37,833. Other decreases of $70,887 were for staff movements including retirements, promotions, resignations and terminations.

Bad Debts $539,898

There was an increase in bad debts compared to 2008 as a result of the auto sector collapse which saw 3 large bankruptcies in our service territory, coupled with a larger number of bankruptcies for residential and smaller businesses over 2008.

Postage & Stationery $137,461

As of January 12, 2009, Canada Post increased postage rates. Regular postage increased from $0.52 to $0.54 (3.85%) and the presort postage rates increased from $0.48 to $0.51 (6.25%). In addition to the increase in rates, Hydro One Brampton also experiences an increase in number of customers from year to year.

Meter Reading ..... ($179,032)

In 2009, the contractor costs associated with meter reading were lower by $167,081, due smart meters installed to-date. In 2009, 17,994 of the readings came through Itron to MVRS while 111,996 came from SerViewCom smart meter readings.

Tree Clearing $123,485

Hydro One Brampton creates its work and maintenance plan based on three distinct geographical areas. In 2009, the tree clearing plan was for a larger-sized geographical area.

Regulatory Expenses $38,366

The OEB assessment costs were higher by $32,582 in 2009.

Load Dispatching $2,982

In 2009, the costs were comparable to the previous year.

Consumer Premises ..... ($66,655)

Less meter base repairs were required compared to 2008, as smart meter installations were performed in the newer areas of the city.

Management Expenses $29,020

Corporate function and service charges from Hydro One increased as compared to 2008.

Meter Maintenance ..... ($8,798)

Meter Maintenance expenses were comparable to prior year.

Line Maintenance ..... ($229,012)

The decrease in Line Maintenance is due to decreased underground primary maintenance as a result of more consistent winter and spring weather.

Other $110,739

“Other” is the total of all other changes in costs included in Hydro One Brampton’s OM&A costs, and is within the materiality threshold of $300,000.

2010 COST DRIVERS

Wages and Benefits $1,064,945

In 2010, the planned hiring of new incremental personnel at a cost of $227,924 will consist of:

1. Assistant Supervisor – Customer Accounts (3rd quarter)
2. Customer Accounts Representative (1st quarter)
3. Two Line Apprentice (3rd quarter)
4. Outage Planning Coordinator (2nd quarter)
5. Software Developer (2nd quarter)

Wages are planned to increase by $147,948 and overtime by $50,000. Other increases of $837,021 were for staff movements including prior year staff additions, retirements, promotions, resignations and terminations.

Bad Debts ..... ($452,830)

The one-time large bankruptcies in the auto sector in 2009 are not expected to recur in 2010.

Postage & Stationery $216,297

In January, 2010, Canada Post increased postage rates. Regular postage increased from $0.54 to $0.57 (5.56%) and the pre-sorted postage rates increased from $0.51 to $0.53 (3.92%). In addition to the increase in rates, Hydro One Brampton also experiences an increase in number of customers from year to year.

Meter Reading ..... ($441,975)

In 2010, the contractor costs associated with meter reading are planned to be lower due to more customers with smart meters being read on SerViewCom.

Tree Clearing ..... ($28,853)

Hydro One Brampton creates its work and maintenance plan based on three distinct geographical areas. In 2010, the tree clearing plan is for a smaller-sized geographical area than in 2009.

Regulatory Expenses $95,507

The regulatory expenses are expected to be higher due to the hiring of an additional full time staff required to insure regulatory compliance.

Load Dispatching $95,536

In 2010, the costs were comparable to the previous year.

Consumer Premises $29,155

A modest increase in city residential service changes and meter base repairs is expected in 2010.

Management Expenses $247,986

Management expenses are expected to increase due to the service charges from Hydro One.

General Administrative Salaries and Expenses $246,065

These expenses are expected to increase due to technology upgrades.

Collecting $244,167

Collecting expenses are expected to increase due to a higher number of disconnects as a result of the economy.

Meter Maintenance $853,859

The increase is mainly associated with Hydro One Brampton's smart metering program. Throughout the implementation of this program, it was decided to focus on installing meters on customers in the parts of the city that would present the least amount of failed meter bases and failed equipment. All questionable areas, those areas that were expected to have a high failure rate, were postponed and will be completed in 2010. As a result, an additional $400,000 was budgeted to cover off theses costs in 2010. It is also expected that Hydro One Brampton will be paying approximately $320,000 in software costs associated with the smart metering program once the installation project is completed. There were no costs for this in 2009. In order to complete the commercial smart meter installations, Hydro One Brampton utilized its own metering crews in 2009. As a result, there were only a minimal number of cross phase tests completed in 2009 due to the reallocation of metering crews to the smart metering project. In 2010, it is expected that an additional $100,000 of cross phase testing work will be completed as compared to 2009.

Line Maintenance $200,568

The increase in Line Maintenance is expected due to ageing distribution system.

Disallowable Costs in Capital $3,647,467

Under IFRS, an item of property, plant and equipment (PP&E) is recognized only if it is probable that a future economic benefit associated with the item will flow to the entity and its cost can be measured reliably. A similar principle applies under Canadian Generally Accepted Accounting Principles (CGAAP).

One of the main differences between IFRS and CGAAP relates to the determination of the carrying amount of PP&E, specifically what should be included in that "cost", especially where assets have been constructed by the entity internally.

Given that IFRS only allows the inclusion of directly attributable costs to be capitalized as part of the cost of an item of PP&E, and further, explicitly disallows administration and other general overheads, the Company performed an analysis of its method of accounting for PP&E to identify costs that are considered to be non-directly attributable and therefore do not meet the criteria for capitalization under IFRS. The amount of non-directly attributable costs that have been moved from capital to OM&A for 2010 is $3,647,467.

Other $186,446

"Other" is the total of all other changes in costs included in Hydro One Brampton's OM&A costs, and is within the materiality threshold of $300,000.

2011 COST DRIVERS

Wages and Benefits $459,649

In 2011, the planned hiring of new incremental personnel at a cost of $254,516 will consist of:

1. Credit Representative (1st quarter)
2. Customer Accounts Representative (1st quarter)
3. Line Apprentice (3rd quarter)
4. Human Resources Manager (2nd quarter)
5. Conservation and Demand Management Representative (2nd quarter)

Wages are not planned to increase in 2011. There will be increases of $205,135 for staff movements including prior year additions, retirements, promotions, resignations and terminations.

Conservation and Demand Management $70,949

This increase is associated with the hiring of an additional position to ensure compliance and with the government's latest CDM targets.

Bad Debts $10,296

It is expected that bad debts will increase slightly due to customer growth.

Postage & Stationery $119,267

It is expected that Canada Post will increase postage rates and the pre-sorted postage. Customer growth will increase the postage expense.

Meter Reading $848,611

In 2011, is expecting to incur monthly meter reading costs directly from the MDR.

Tree Clearing $3,795

No significant variance is expected from the prior year for tree clearing.

Regulatory Expenses $100,000

The regulatory expenses are expected to be higher largely due to incremental costs expected to be incurred with this rate application. Intervener costs $50,000 and Legal costs $20,000.

Load Dispatching $27,824

In 2011, the costs are expected to be comparable to the previous year.

Consumer Premises $16,094

A modest increase in city residential service changes and meter base repairs is expected in 2011.

Management Expenses ..... ($110,212)

Management expenses will decrease due to the Corporate function and service charges from Hydro One.

Meter Maintenance ..... ($612,188)

The decrease is due to the transfer of smart metering software cost responsibility from the metering department to Meter reading ($300,000). Failed meter base repair costs are expected to decrease by $285,000 which will be offset by incremental smart metering maintenance costs.

Line Maintenance $683,938

The increase in Line Maintenance is expected due to ageing distribution system.

Disallowable Costs in Capital ..... ($547,274)

Under IFRS, an item of property, plant and equipment (PP&E) is recognized only if it is probable that a future economic benefit associated with the item will flow to the entity and its cost can be measured reliably. A similar principle applies under Canadian Generally Accepted Accounting Principles (CGAAP).

One of the main differences between IFRS and CGAAP relates to the determination of the carrying amount of PP&E, specifically what should be included in that “cost”, especially where assets have been constructed by the entity internally.

Given that IFRS only allows the inclusion of directly attributable costs to be capitalized as part of the cost of an item of PP&E, and further, explicitly disallows administration and other general overheads, the Company performed an analysis of its method of accounting for PP&E to identify costs that are considered to be non-directly attributable and therefore do not meet the criteria for capitalization under IFRS. The amount of non-directly attributable costs that have been moved from capital to OM&A for 2010 is $3,647,467.

Other $195,210

"Other" is the total of all other changes in costs included in Hydro One Brampton's OM&A costs, and is within the materiality threshold of $300,000.

OM&A COST PER CUSTOMER

AND PER FULL TIME EQUIVALENT

The table below provides the average Operating, Maintenance, and Administration cost per customer and per full time equivalent employee.

Table 1: OM&A Cost per Customer and per FTEE

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test
Number of Customers	120,293	126,026	128,522	130,963	132,427	133,888
Total OM&A	16,155,651	15,925,811	17,173,680	17,836,429	24,040,769	25,306,728
OM&A Cost/Customer	**$ 134.30**	**$ 126.37**	**$ 133.62**	**$ 136.19**	**$ 181.54**	**$ 189.01**
Number of FTEEs	183	202	207	211	225	231
FTEEs/Customer	0.00152	0.00160	0.00161	0.00161	0.00170	0.00173
OMA Cost/FTEE	**$ 88,282**	**$ 78,841**	**$ 82,965**	**$ 84,533**	**$ 106,848**	**$ 109,553**

ONE TIME COST ANALYSIS

Hydro One Brampton does not have any significant one-time costs included in 2011 test year of this rate application.

REGULATORY COSTS

Hydro One Brampton's regulatory costs consist primarily of regulatory staff resources, the Board's annual dues, costs for annual rate publications, and the costs associated with preparation of the 2011 Cost of Service Rate Application. Table 6 outlines historical, Bridge Year, and Test Year costs.

The changes in regulatory costs from 2006 to 2007 of $129,073 were primarily due to an increase in OEB Annual Assessment Costs by $81,461. OEB Section 30 costs increased by $14,289 and staffing expenses increased by $22,911. Other Costs associated with load shape analysis as defined in the Board's "Staff Proposal Regarding Rate Classification and Associated Load Data Requirements for Cost Allocation," dated May 26, 2006 account for an additional $8,000 and local newspaper advertisements relating to rate change account for the remaining difference.

The reduction in regulatory costs of $13,180 between 2007 and 2008 were due to the change in Other Costs. Load shape analysis was not required in 2008 and a reduction in newspaper advertisements in this year, accounting for $10,381. A decrease in OEB Annual Assessment Costs and an increase in OEB Section 30 Costs and staffing expenses account for the remaining difference.

Regulatory costs between 2008 and 2009 increased by $25,757 mainly due to increases in OEB annual assessment costs of $32,582 and slightly offset by a decrease in OEB Section 30 costs of $8,096.

The change from 2009 to the 2010 Bridge Year of $106,951 is largely due to the addition of one full-time employee at the end of 2009. This staffing addition was required in order to maintain regulatory reporting, policies, and changing legislations. Additional increases in OEB Annual Assessment Fees, OEB Section 30 costs and changes in regulatory salaries account for the remaining increase.

The change from the 2010 Bridge Year to the 2011 Test Year of $100,000 is attributable to expected intervenor costs of $50,000, and $20,000 relating to legal fees associated with the 2011 Cost of Service Rate Application. The balance relating to expected increases of $20,000 for the OEB Annual Assessment Fees and the remaining $10,000 relating staffing expenses.

Hydro One Brampton is requesting that the total amount associated with the 2011 Cost of Service Rate Application of $70,000 be recovered in one year.

Exhibit 4 Tab 2 - Table 6: Regulatory Cost Schedule

REGULATORY COST SCHEDULE											
Regulatory Cost Category	UsofA Account 5655	UsofA Account Balance	Ongoing or One-Time Cost?	Actual 2006	Actual 2007	Actual 2008	Actual 2009	2010 Bridge Year	% Change in Bridge Year vs. 2009 Actual	2011 Test Year	% Change in Test Year vs. Bridge Year
OEB Annual Assessment	Y		Ongoing	325,411	406,872	393,812	426,394	430,004	0.85%	453,027	5.35%
OEB Hearing Assessments (applicant initiated)	Y		Ongoing	-	-	-	-	-	-	-	-
OEB Section 30 Costs (OEB initiated)	Y		Ongoing	9,234	23,523	27,977	19,881	25,000	25.75%	21,973	-12.11%
- Intervenor Costs (2011 COS Application)	Y		One-Time	-	-	-	-	-	-	50,000	100%
Expert Witness Cost (regulatory matters)	Y		Ont-Time	-	-	-	-	-	-	-	-
Legal Costs (regulatory matters)	Y		One-Time	-	-	-	-	-	-	20,000	100%
Consultants Costs (regulatory matters)	Y		One-Time	-	-	-	-	-	-	-	-
Operating Expenses (associated with staff resources allocated to regulatory matters)	Y		Ongoing	360,956	383,867	389,674	390,976	489,998	25.33%	500,000	2.04%
Operating Expenses (associated with other resources allocated to regulatory matters)	Y		Ongoing	-	-	-	-	-	-	-	-
Other Regulatory Agency Fees or Assesments	Y		Ongoing	800	800	800	800	-	-	-	-
Any Other Costs (regulatory matters) *Newpaper Ads/ Load Shape Analysis*	Y		One-Time	-	10,412	31	-	-	-	-	-
Intervenor Costs	Y		One-Time	-	-	-	-	-	-	-	-
TOTAL				**696,401**	**825,474**	**812,294**	**838,051**	**945,002**		**1,045,000**	

LOW-INCOME ENERGY ASSISTANCE PROGRAMS

On March 10, 2009, the Ontario Energy Board issued a Notice of Proposal to Amend Codes, which set out proposed amendments to the Board's *Distribution System Code*, *Retail Settlement Code* and *Standard Supply Service Code*. These proposed amendments address matters such as bill payment, security deposits and disconnection notice periods. The proposals included recommendations for amendments tailored specifically to low-income electricity customers.

Based on the Minister's request, the Board has revised the proposed code amendments. Once revised, the proposed code amendments endeavour to address the needs of low-income electricity consumers through proposed code amendments applicable to all residential customers. Although there are no rules specific to low-income customers, the Board believes that the package of proposed amendments will benefit all customers, including low-income residential electricity customers.

Hydro One Brampton will continue to work within the defined code amendments to provide the needs of low-income electricity consumers.

HOBNI does not foresee any additional OM&A costs arising from the proposed code amendments.

GREEN ENERGY ACT EXPENDITURES

The OEB requires that LDCs submit their Green Energy Plan to the OPA for review. After review, the OPA then provides a letter of comment to the LDC. HOBNI is currently in the process of submitting their Green Energy Plan to the OPA. Once the OPA provides a letter of comment, it will be made available and included in HOBNI's Green Energy Plan.

Hydro One Brampton's 2011 - 2015 Green Energy Plan is included for reference as part of this Exhibit on the following pages as **Appendix G**.

APPENDIX G



Green Energy Plan

2011 - 2015

ENGINEERING DEPARTMENT

May 13, 2010

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1. Executive Summary

The Hydro One Brampton Networks Inc. (HOBNI) Green Energy Plan (Plan) presents the Company's response to the *Green Energy and Green Economy Act, 2009* ("GEGEA") in alignment with HOBNI's corporate strategy. The Plan covers the five year period from 2011 to 2015 and includes the incorporation of renewable energy generation, development of HOBNI's Smart Grid and promotion of energy conservation. HOBNI considers this Plan to be a prudent and responsible. The Plan's development is based on the Company's experience with the implementation of renewable energy generation connections in Ontario since 2006, its Conservation and Demand Management ("CDM") programs since 2004, and a measured approach to Smart Grid investment focused on studies, demonstration projects, planning and training. The spending reflected in the Plan went through the same business planning and approval process as all other investments in our distribution system.

The total costs of investments contained in the Plan are summarized in the table below.

Green Energy Spending 2010 - 2015						
Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Generator Connections (Capital)	$300,000	$300,000	$306,000	$312,000	$318,000	$324,000
Smart Grid (Capital)	$733,000	$750,000	$765,000	$780,000	$795,000	$812,000
OM&A	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
Less Generator Funded Costs	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000
Totals	**$1,033,000**	**$1,050,000**	**$1,072,000**	**$1,092,000**	**$1,113,000**	**$1,136,000**

The available capacity on HOBNI's Distribution system to accommodate renewable generation connection is approximately 720 MW. The distribution system has 166 MW available on the 44kV system and 555 MW available on the 27.6kV system.

Approximately 80% of the HOBNI distribution system will accommodate connections to generation without the need for expansion of new lines. However, as the number of generator connections increase, the short circuit fault levels also increase on the distribution system. Currently the only known constraint on HOBNI's distribution system is the fault level on the EZ Bus at Bramalea TS. There will be no generators allowed to connect to any feeders that are supplied by the EZ Bus at Bramalea TS. HOBNI's feeders that are affected by this constraint are the Bramalea M43, M44, M47 and M48.

The evolution of HOBNI's system into a Smart Grid offers value to both HOBNI's generation and load customers. A smarter distribution system will enhance the reliability, security and power quality of the system through automation and enablement of increased amounts of cleaner, renewable distributed generation; it will allow for new conservation and demand management programs by improving load management and overall understanding of customer load profiles through innovative two way communication; and it will improve asset condition monitoring and trouble call responses with more accurate data and enhanced system controls.

HOBNI proposes projects that would involve research and pilots into such technologies as real time monitoring, control devices, remediate faults and outage management & restoration systems. Several projects in the next 5 years include:

- ***Smart Meter Integration with OMS***

  In 2011, HOBNI plans on integrating the Smart Meter system with the Outage Management System (OMS). Smart meter data will be transmitted from the Smart Meter system to the OMS system in real time, allowing the prediction engine in OMS to accurately pinpoint failed equipment on the distribution

system. It will also identify when the meter is removed and will help identify theft of power or meter tampering issues.

- ***Feeder Automation Equipment***

  HOBNI continues to investigate and install automation equipment on our distribution feeders. These remotely operable switches will replace existing air insulated manual equipment. In 2011 new solid dielectric, remotely operable, sectionalizing switches will be installed; these units will allow for dynamic system load control. Also, in 2011 solid dielectric recloser equipment will be installed to allow for automatic feeder sectionalizing during faults.

- ***Distributed Generation***

  HOBNI is required to monitor distributed generation installations with capacities that are greater than 250 kW. Exploratory work has been initiated on how best to collect all required metering and Supervisory Control and Data Acquisition (SCADA) data, with hopes that a single metering / SCADA solution can be utilized. In 2010 equipment from PML will be investigated for suitability. This equipment is to communicate to the SCADA master via Bell I/P modems in real time. This data will then be utilized by our Control Centre as well as sent to Hydro One Networks via our fibre based ICCP master to master link.

- ***Safety / Security***

  In 2009 a Municipal Substation (MS) security initiative was implemented. I/P based cameras were installed at three MSs and have proven to work well. These installations bring back real time video to the HOBNI Control Room. In 2010 this initiative is being expanded to increase the number of locations being monitored.

- ***Communications Expansion***

  As distribution automation increases on the system, HOBNI's communication network will require expansion. This work will involve expanding our fibre optic network, increasing the number of spread spectrum radio nodes (both 900 MHZ and 2.4 GHZ) as well as investigating new communication technologies. These new technologies may include secure I/P over the cellular network or Wi-Max solutions.

2. Generator Connections Current & Future Outlook

2.1. Planning Criteria for Generator Connection

The planning criteria used to evaluate Generator Connections to HOBNI's system are listed below:

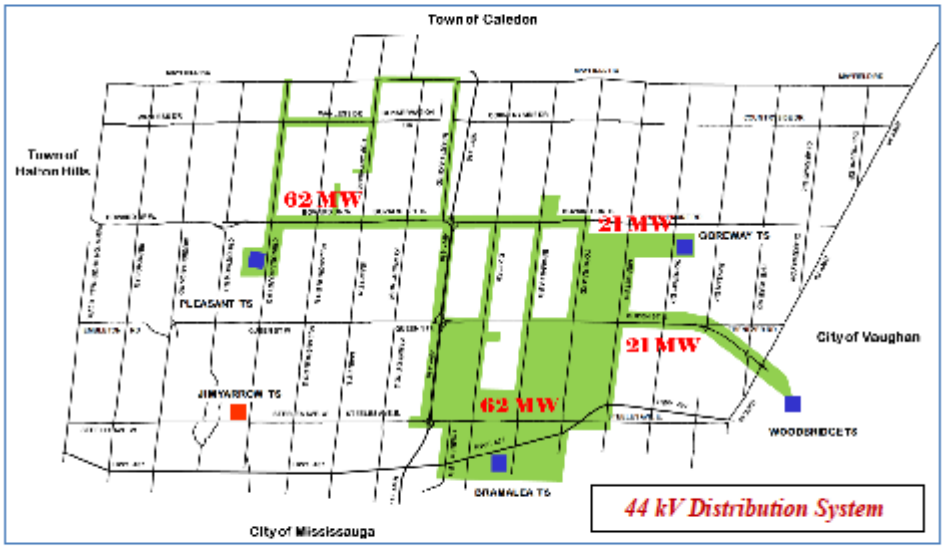
- Bus voltages should vary between 0.95 p.u and 1.05 p.u during normal and contingency situation.
- Bus voltage swing should not exceed 5.0% during switching operation.
- Line loading should not exceed 50% of thermal rating.
  - 50% Feeder rating for 44 kV is 300 A = 20.6 MW
  - 50% Feeder rating for 27.6 kV is 300 A = 12.9 MW
  - 50% Feeder rating for 13.8 kV is 155 A = 3.3 MW
  - 8.32 kV system – Not allowed to connect, will become obsolete
  - 4.16 kV system - Not allowed to connect, plan is to convert to 27.6 kV over the next 7 years.
- Reverse Power flow through HOBNI transformers should not exceed 50% of rated KVA.
- Short circuit values should be less than 20 kA at Hydro One Networks Inc. (HONI) 44 kV & 27.6 kV bus.
- Short circuit values should be less than 20 kA for the 27.6 kV bus at HOBNI's Jim Yarrow Transmission Station.
- Short circuit values should be less than 20 kA for HOBNI's Municipal Substation bus.
- Short circuit values should be less than 16 kA at HOBNI's load modules and customer breakers.

2.2. Available Feeder Capacities for Generation Connection

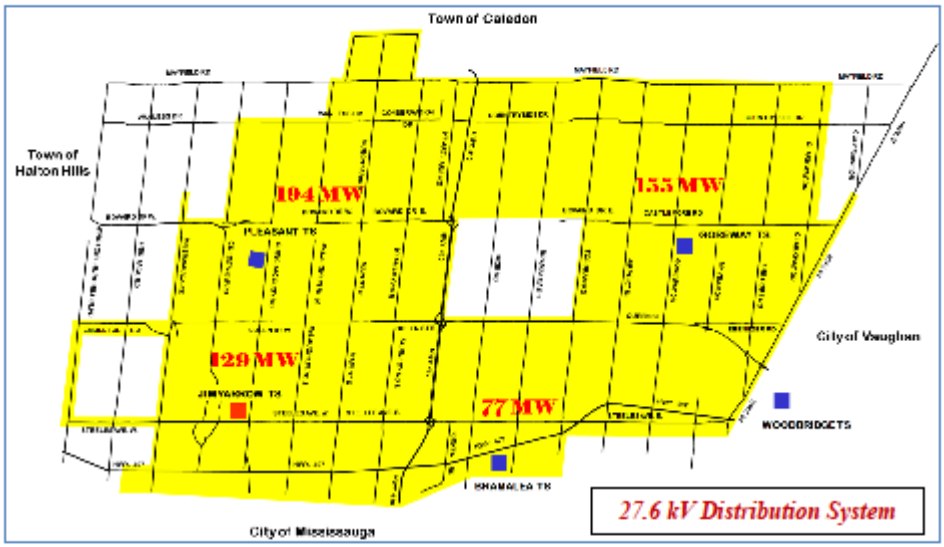
The following table breaks down the total capacity on HOBNI's distribution system for generation connection:

Table 1 – HOBNI Feeder Capacity

Station/Feeders	Available MW for Generation Connection	Notes
Woodbridge TS – 44 kV (M16)	20.6	
Bramalea TS – 44 kV (M26, M27, M28, M43, M44,M47,M48)	61.8	M43, M44, M47 and M48 are on the EZ Bus which is limited due to short circuit fault levels – therefore no connection to these feeders.
Bramalea TS – 27.6 kV (M2, M3, M4, M5, M6, M10)	77.4	
Goreway TS – 44 kV (M36)	20.6	
Goreway TS – 27.6 kV (M41, M42, M43, M44, M45, M46, M47, M48, M49, M50, M51, M52)	154.8	
Pleasant TS – 44 kV (M21, M22, M24, M26)	61.8	M21 has not been taken out of the station - therefore no connection to this feeder
Pleasant TS – 27.6 kV (M9, M10, M11, M12, M13, M14, M43, M44, M45, M46, M47, M48, M66, M67, M68)	193.5	
Jim Yarrow TS – 27.6 kV (M1, M3, M4, M5, M6, M7, M8, M10, M11, M13)	129	
Totals:	**719.5 MW**	



The available capacity on HOBNI's Distribution system to accommodate generation connection is approximately 720 MW. The distribution system has 166 MW available on the 44kV system (pictured above) and 555 MW available on the 27.6kV system (pictured below).



2.3. Connection & Fault Level Constraints

Approximately 80% of HOBNI's distribution system will accommodate connection to generation without the need for expansion of new lines. Generators wanting to connect in the 20% of un-served areas would be connected per Ontario Energy Board's (OEB's) Distribution System Code (DSC).

HOBNI does have plans to expand into the un-served areas of the City. The new 27.6 kV yards at Pleasant TS and Goreway TS will allow new feeders to service the north-west and north-east corners of the City. Current tentative plans include the following expansions:

- 2010 – two (2) 27.6 kV feeders out of Goreway TS
- 2011 to 2014 – one (1) 27.6 kV feeder per year out of Goreway TS
- 2011 to 2014 – one (1) 27.6 kV feeder per year out of Pleasant TS

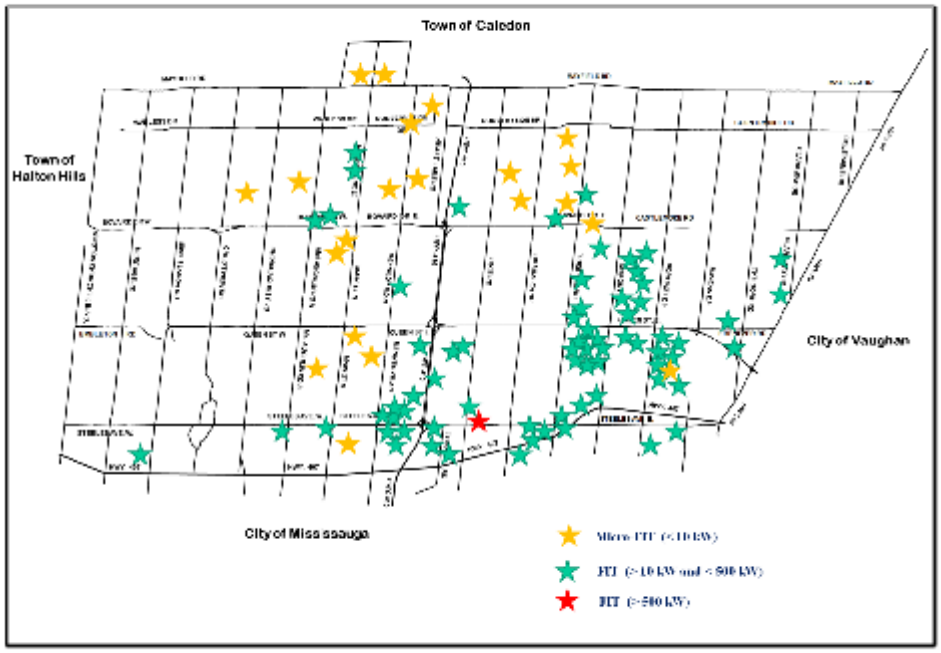
If the expansions are executed according to plan, HOBNI will have an additional 103 MW of capacity for generator connection by the year 2014.

As generator connections increase, the short circuit fault levels also increase on the distribution system. Currently the only known constraint on HOBNI's distribution system is the fault level on the EZ Bus at Bramalea TS. There will be no generators allowed to connect to any feeders that are connected to the EZ Bus at Bramalea TS. The HOBNI's feeders that are affected by this constraint are the M43, M44, M47 and M48.

2.4. Current Connections and Outlook

Since the official start of the FIT & Micro-FIT programs back on November 2009, HOBNI currently has applications for the following:

- 70 FIT applications totaling approximately 23.8 MW
  - All but one under 500 kW
  - Only one over 500 kW – 3.2 MW Biomass Unit
- 28 Micro-FIT applications totaling approximately 208.1 kW
  - 8 commercial solar
  - 20 residential solar



Renewable Generator Connection Applications

HOBNI's goal is to support the enablement of renewable generation in Ontario. However, areas remain in which the connection of renewable generation is not currently feasible due to existing system constraints. Under the Green Energy Act, distributors are obligated to respond to the potential for additional connections where these are deemed economic. Therefore, connection requests that are in excess of existing available system capacity will be assessed with respect to whether they can be enabled with economic additions to wires facilities. The Ontario Power Authority (OPA) will do this assessment for transmission; HOBNI will do the assessment of distribution enabling investments. In both cases, the assessments will be guided by OEB's direction with respect to cost allocation and the degree of risk that expected generation projects will not proceed. HOBNI is also working with the OPA to ensure the availability of distribution capacity is considered in the processes related to issuing and managing FIT contracts.

HOBNI notes that the incorporation of large amounts of renewable energy generation into its system will be an extensive and time consuming process. Under the proposed FIT application framework, HOBNI will continue to track and monitor the connection requests that have capacity allocations and make adjustments to its system expansion and enhancement plans according to changing conditions that would provide opportunity for these applicants to obtain a FIT contract.

2.5. OPA's Letter of Comment

In this section of the Plan, the distributor must include the letter of comment on the Plan provided by the OPA.

3. Renewable Generation Connection Information

3.1. HOBNI FIT Application Process

Phase	Purpose	Owner	Estimated Turnaround Time
Pre-FIT Consultation	Assist proponent to gather information necessary to apply for FIT, such as preliminary transmission and distribution testing, broad cost-estimates, etc.	HOBNI	5 days upon the receipt of a completed Form A - Pre-FIT Consultation Application.
FIT Contract Application	A process that is managed by the OPA for assessing applications and issuing contracts for FIT Allocation Exempt or Non Allocation Exempt. DAT & TAT.	OPA	60 days upon completed OPA FIT application.
Connection Impact Assessment (CIA)	After the FIT contract has been awarded, the applicant files a CIA with Hydro One Brampton for a more formal assessment of the impact of connecting the generator to the system. A System Impact Assessment (SIA) must be completed by the IESO for projects >10MW. A very high-level connect cost assessment will be provided as part of the CIA package back to the applicant.	HOBNI/IESO	60 days upon the receipt of a completed Form B - Connection Impact Assessment (CIA) Application. Longer than 60 days if projects involve other LDC(s).
Connection Cost Estimate (CCE)	If the applicant requires a detailed connection cost assessment, the applicant can complete a CCE.	HOBNI	90 days upon the receipt of a completed CCE study agreement by the generator. The CCE study agreement and cost are included as part of the CIA package.
Connection Cost Agreement (CCA)	Once agreement of the scope and cost are reached, the generator is required to sign a Connection Cost Agreement to recover the costs Hydro One Brampton will incur to connect the project to the distribution system.	HOBNI	6 months from the time the CIA is completed. The generator is required to complete a CCA study agreement along with payment in order to initiate the CCA process. The CCA study agreement and payment information will be included as part of the CIA package.
Engineering, Procurement and Construction	After submitting the CCA and payment, detailed design and construction may begin. The project in-service date will be set. Once all of the required work and approvals are completed, the Distribution Connection Agreement, signed by Hydro One Brampton and the generator, provides an outline of the connection as well as the roles and responsibilities of each party.	HOBNI	The project in-service day will be determined at the project kick-off meeting which will take place no later than 45 days after CCA execution.

3.2. Costing of Projects & Activities

HOBNI plans on connecting over 40 MW of renewable generation per year for the next five years. The numbers of connections in the forecast include 25 MicroFIT and 75 FIT projects per year.

Generator Connection Spending 2010 - 2015						
Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Expansions (capital)	-	$200,000	$204,000	$208,000	$212,000	$216,000
Enabling Improvements (Capital)	$300,000	$100,000	$102,000	$104,000	$106,000	$108,000
OM&A	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
Less Recoverable	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000	-$250,000
Totals	**$300,000**	**$300,000**	**$306,000**	**$312,000**	**$318,000**	**$324,000**

The sections below describe the activities and investments that HOBNI will undertake to facilitate the achievement of these targets in a timely and prudent manner.

OM&A – HOBNI's costs included in this Plan cover Development work related to generation connections. Investments in this area allow HOBNI to undertake further research and development to understand and address the complexities associated with generation connections and the development of new standards for generation connections. Investments in this area will also address the increasing need to interface with generator connection proponents as a result of the forecasted increases in connection volumes.

Connection Assets – HOBNI has assumed that this investment only covers the work associated with providing isolating devices or other assets required for the specific generator's connection to HOBNI's system. Consistent with the Distribution System Code, HOBNI does not include the expansion costs associated with? its main distribution system to build a new line to the ownership demarcation point serving one or more generation customers as a Connection Asset. Generators are responsible for all costs associated with Connection Assets. As such, the costs associated with work on the main distribution system to physically connect and isolate Connection Assets are covered by capital contributions from customers and result in no net capital additions to HOBNI's rate base, and no impact on distribution rates.

Expansion - HOBNI has based this Plan on its assumption that Expansion of the distribution system to connect renewable energy generation includes the following types of investments carried out to serve one or more renewable energy generation facilities:

- Expand or build out the distribution system to the ownership demarcation point of the renewable energy generation facility;
- Rebuilding a single-phase line to three-phase;
- Rebuilding an existing line with a larger size conductor;
- Rebuilding or overbuilding an existing line to provide an additional circuit;
- Converting a lower voltage line to operate at higher voltage;
- Replacing a transformer to a larger MVA size;
- Upgrading a voltage regulating transformer or station to a larger MVA size;
- Building new express feeders to connect renewable energy generation;
- Providing new Municipal Stations and/or additional capacity at existing Municipal Stations.

These capital investments modify/upgrade the distribution lines and stations to allow the connection of one or more renewable energy generation facilities to HOBNI's system while preserving reliability and power quality. The costs associated with expansion investments required to connect all anticipated renewable generation facilities in 2010 are assumed to be covered by the funding requested in this Plan. For expansion investments

beyond the work covered in this Plan HOBNI will contribute up to the maximum expansion cost cap of $90,000 per MW of connecting generator capacity established under the Distribution System Code. Any incremental expansion costs beyond the proposed cap are to be borne by the generator(s).

Renewable Enabling Improvements – these investments address modifications or additions to the main distribution system in order to accommodate increased levels of renewable energy generation. Renewable Enabling Improvement investments include the following:

- Modifications or additions to manage and control 2-way electrical flows or reverse flows (e.g. bidirectional reclosers, tap changer controls or relays, replacing breaker protection relays)
- Modifications to, or the addition of, electrical protection equipment.
- Modifications to, or the addition of, voltage regulating transformer or station controls.
- Provision of protection against islanding (transfer trip or equivalent).
- Design and installation of SCADA systems and telecommunication equipment.

Implementation of these Renewable Enabling Improvement investments will facilitate and streamline the connection of renewable energy generators by eliminating some of the technical limitations to the connection of new generation. In addition, Renewable Enabling Improvement investments will also dovetail with the development of the Smart Grid and this will ensure proper protection, automation and control measures are in place to facilitate the connection and operation of renewable energy generation.

4. Smart Grid Development

4.1. Smart Grid Strategy

HOBNI is taking a diligent and prudent approach towards its investment plans for Smart Grid. This is particularly important given the substantial cost and expert resources required to implement this relatively new concept using systems that have not been previously deployed. Additional complexities also arise due to the requirement that the Smart Grid enables the distribution system to accommodate larger volumes of distributed generation.

HOBNI has established five value drivers for the Smart Grid work:

1. Increased reliability,
2. Increased operations effectiveness,
3. Faster restoration,
4. Customer enhancement using smart meter/analytical tools to effect conservation and
5. Lower carbon footprint.

HOBNI's Smart Grid plan builds on the Ontario Government mandated foundations of an intelligent smart meter infrastructure, conservation and demand management ("CDM") implementation needs and the integration of renewable distributed generation into the distribution system.

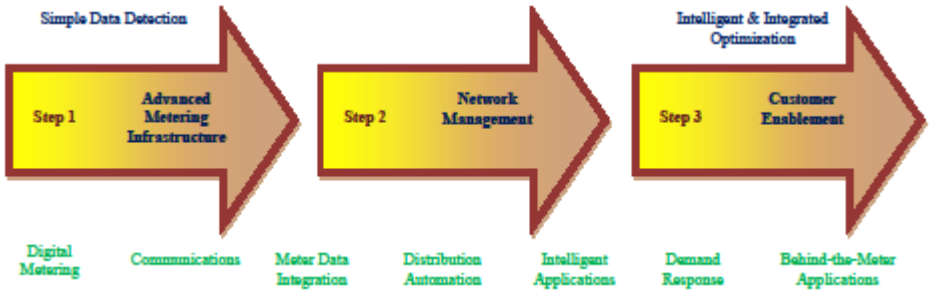
In order to understand how these smart grid value drivers can best be achieved, HOBNI will proceed with research and pilot projects to test new technologies and systems prior to recommending a corporate-wide deployment. The main objective of these initiatives is to innovate, test and prove new and emerging technologies. This will permit HOBNI to proactively define and implement measures that will eventually transform the current distribution system into a Smart Grid by making appropriate capital investments, asset solutions, standards and/or replacement strategies.

4.2. Smart Grid Planning

The evolution of HOBNI's system into a Smart Grid offers value to both HOBNI's generation and load customers. A smarter distribution system will enhance the reliability, security and power quality of the system through automation and enablement of increased amounts of cleaner, renewable distributed generation; it will allow for new conservation and demand management programs by improving load management and overall understanding of customer load profiles through innovative two way communication; and it will improve asset condition monitoring and trouble call responses with more accurate data and enhanced system controls.

HOBNI will be following a three step process to develop the Smart Grid long-term plan. The first step was to focus on system automation by leveraging the new communication infrastructure put into place for Smart Meters. The second step involves formulating plans to investigate, understand and prepare for new innovative technologies in the area of Network Management. The final step of the long-term plan will target studies in the area of green energy technologies such as automated home energy networks that will help in the enabling of the Smart Grid.

Evolution of the Smart Grid



4.3. Smart Grid Projects

4.3.1. Smart Meter Integration with OMS (2011)

In 2011, HOBNI plans on integrating the Smart Meter system with the OMS system. 'Last gasp' smart meter data will be transmitted from the Smart Meter system to the OMS system in real time, allowing the prediction engine in OMS to accurately pinpoint failed equipment on the distribution system. It will also allow the monitoring of meters and immediately advise HOBNI when tampering is occurring at the meter thereby reducing theft of power losses.

4.3.2. Feeder Automation Equipment

HOBNI continues to investigate and install automation equipment on our distribution feeders. We currently have auto transfer systems installed at the Bramalea City Centre, Shopper's World and in the downtown core.

In 2010 three new 46 KV Joslyn VBM switches will be installed at MS 19 as a pilot project. These remotely operable switches will replace existing air insulated manual equipment.

In 2011 new solid dielectric, remotely operable, sectionalizing switches will be installed at two underground vault installations in the downtown core. These units will allow for dynamic system load control as well as allow switching to be done safely above grade.

In 2011 solid dielectric recloser equipment is to be installed on a distribution feeder to allow for automatic feeder sectionalizing during faults. One unit will be tested and several more installed in the near future depending on the success of the project. This same equipment can be 'repackaged' into pad mounted form for installation at existing pad mounted switchgear installations.

4.3.3. *Distributed Generation*

New province wide green energy initiatives require HOBNI to monitor distributed generation installations with capacities greater than 250 KW. There are currently 40 installations of this type in the planning stages in Brampton.

Investigation has begun on how best to collect all required metering and SCADA data at these locations. Investigation is currently underway with hopes that a single metering / SCADA solution can be utilized.

In 2010 equipment from PML will be investigated for suitability. This equipment is to communicate to the SCADA master via Bell I/P modems in real time. This data will then be utilized by our Control Centre as well as sent to Hydro One Networks via our fibre based ICCP master to master link.

4.3.4. *Safety / Security*

In 2009 an MS security initiative was implemented. I/P based cameras were installed at three MSs and have proven to work well. These installations bring back real time video to HOBNI's Control Room. In 2010 this initiative is being expanded to increase the number of locations being monitored.

4.3.5. *Communications Expansion*

Communication to field devices is the backbone that all feeder automation relies on. As needs arise for more distribution automation our communication networks will be required to expand. This expansion will involve expanding our fibre optic network, increasing the number of spread spectrum radio nodes (both 900 MHZ and 2.4 GHZ) as well as investigating new communication technologies. These new technologies may include secure I/P over the cellular network or Wi-Max solutions.

4.4. Smart Grid Budget

Smart Grid Spending 2010 - 2015						
Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Smart Grid	$733,000	$750,000	$765,000	$780,000	$795,000	$812,000
Totals	**$733,000**	**$750,000**	**$765,000**	**$780,000**	**$795,000**	**$812,000**

Spending on the Smart Grid program is forecasted to 2015 and shown in the above table.

Appendices

DISTRIBUTION AUTOMATION PLAN 2010

Hydro One Brampton's Distribution Automation Plan is included for reference as part of this Exhibit on the following pages as **Appendix H.**

APPENDIX H



Distribution Automation Plan

2010

PROTECTION & CONTROL DEPARTMENT

May 10, 2010

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1. History

Hydro One Brampton Networks Inc. (HOBNI) began the distribution automation plan in the early 1980's starting with the installation of a Motorola PDP-11 Supervisory Control and Data Acquisition (SCADA) master system and Motorola DATRAC Remote Terminal Units (RTU) at several municipal substations (MS). This gave our Operators access to real time feeder data and allowed for control of Municipal Substation (MS) feeder breakers and reclosers. This initiative was then expanded to include the automation of several switch installations along our distribution feeders using Motorola DAS 100 RTUs connected through leased Bell communication circuits. This provided fault indicator data as well as remote control of our critical switches, allowing for faster feeder restoration and improved outage times.

This phase of the implementation continued for several years, and by 1991 there were 12 municipal substations as well as 67 remotely operable pole top switch locations on line.

2. System Expansion and Innovation

2.1. New SCADA Master Equipment

In 1992, coinciding with our relocation to 175 Sandalwood Parkway West, HOBNI installed new Quindar VMS based SCADA master station hardware and software. This new equipment replaced the legacy Motorola PDP-11 system. This allowed for communication line expansion as well as the use of multiple communication protocols. At this time new communication equipment was also installed that allowed for expansion of the number RTUs connected to the system.

2.2. New Communication Initiatives

The installation of the new SCADA master equipment allowed for the expansion of our SCADA communication network. Previously all communication was achieved through leased Bell lines. This mode of communication became expensive and unreliable.

New technologies were investigated and a Motorola licensed 900 MHZ data radio system was installed. This system allowed for easy system expansion and multiple MS and pole-top RTU locations were connected. After it became clear that the 900 MHZ licensed system was nearing capacity, we began to investigate other communication solutions. This led to the installation of several 900 MHZ spread spectrum radio installations, the installation of 2.4 GHZ spread spectrum system, as well as the introduction of our self healing fibre optic communication rings in the East and West areas of the city.

These systems became the backbone of our SCADA communication network and allowed for increased system expansion. Over the next few years we were able to connect all MSs to our SCADA system and expand our pole-top SCADA installations to over 125 fully controllable sites.

3. Current System Configuration

3.1. SCADA Master Equipment

HOBNI is currently using a Survalent Worldview based master station system on dual redundant WinServ 2003 hosts. There are two Windows XP based operator stations in the Control Room as well as multiple user client work stations located throughout the facility. These are connected via a secure connection to our corporate Local Area Network (LAN).

The master station equipment connects to field equipment through redundant master terminal servers allowing for a total of 64 independent communication lines speaking multiple protocols.

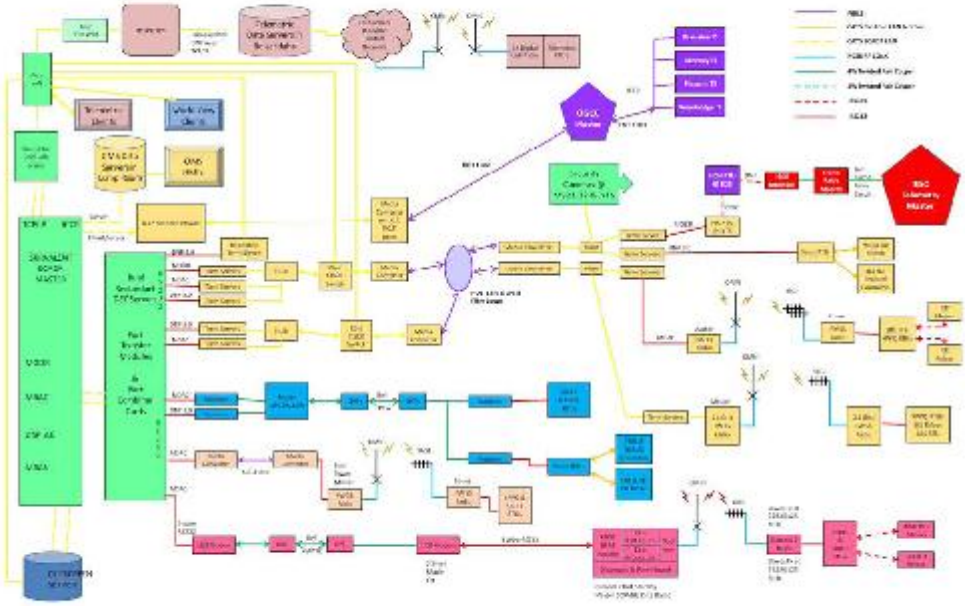
3.2. Remote RTU Communication

HOBNI currently has three bridged four-wire Bell leased communication lines connecting 17 RTUs to our Master system. There are also three individual four-wire communication lines connecting three Municipal Stations. Bell costs have decreased by two thirds since 1991 due to migration away from Bell communication.

The licensed 900MHZ master radio is located on a 20 storey building in central Brampton. It is connected to the SCADA master by a leased four-wire Bell line and communicates to 11 pole top RTUs as well as one MS. The Radio Frequency footprint of this installation covers the entire city of Brampton.

There are currently nine separate spread spectrum communication nodes located throughout the city providing communication the majority of our RTUs. Eight of the nodes are running at 900 MHZ while one is running at 2.4 GHZ. The master radios connect back to the SCADA master via our self healing fibre Wide Area Network (WAN).

Telemetric communication equipment connects to our SCADA master via a terminal server / internet link from the Telemetric data servers in Idaho. This communication equipment uses cellular data channels and can reach any location that has 1X coverage.



Block diagram outlining our various communication systems:

3.3. Remote RTU Equipment

HOBNI has RTU equipment installed at 13 MSs and one TS location, as well as three large customer substations. There are also RTUs installed at 98 overhead switches, 22 pad mounted switches and eight Gas Insulated Switchgear (GIS) auto transfer switchgear.

There are currently RTUs located at seven co-generation sites within Brampton.

Telemetric RTUs are located at more than 50 radio fault indicator locations. This equipment is also used at three overhead switch locations, five spot network vault locations and at two auto-transfer locations.

The SCADA master communicates to several IEDs including EIG NEXUS 1250 meters, PML ION meters, SEL 351R recloser controllers, various ABB and SEL protection relays, S&C intelligent motor operators as well as Schneider 44 KV current / fault sensing installations. This is accomplished by communicating directly to the IED or by using an RTU as a data concentrator.

4. Moving Forward

4.1. Smart Meter Integration with OMS (2011)

In 2011, HOBNI plans on integrating the Smart Meter system with the Outage Management System (OMS). 'Last gasp' smart meter data will be transmitted from the Smart Meter system to the OMS in real time, allowing the prediction engine in OMS to accurately pinpoint equipment on the distribution system.

4.2. Feeder Automation Equipment

HOBNI continues to investigate and install automation equipment on its distribution feeders. There are currently three auto transfer systems installed in Brampton.

In 2010 three new 46 KV Joslyn VBM switches will be installed at MS 19 as a pilot project. These remotely operable switches will replace existing air insulated manual equipment.

In 2011 new solid dielectric, remotely operable, sectionalizing switches will be installed at two underground vault installations in the downtown core. These units will allow for dynamic system load control as well as allow switching to be done safely above grade.

In 2011 solid dielectric recloser equipment is to be installed on a distribution feeder to allow for automatic feeder sectionalizing during faults. One unit will be tested and several more installed in the near future depending on the success of the project. This same equipment can be 'repackaged' into pad mounted form for installation at existing pad mounted switch gear installations.

4.3. Distributed Generation

New province wide green energy initiatives require HOBNI to monitor distributed generation installations with capacities greater than 250 KW. There are currently 40 installations of this type in the planning stages in Brampton.

Investigation has begun on how best to collect all required metering and SCADA data at these locations. Investigation is currently underway with hopes that a single metering / SCADA solution can be utilized.

In 2010 equipment from PML will be investigated for suitability. This equipment is to communicate to the SCADA master via Bell I/P modems in real time. This data will then be utilized by our Control Centre as well as sent to Hydro One Networks via our fibre based ICCP master-to-master link.

4.4. Safety / Security

In 2009 an MS security initiative was implemented. I/P based cameras were installed at three MSs and have proven to work well. These installations bring back real time video to the HOBNI Control Room. In 2010 this initiative is being expanded to increase the number of locations being monitored.



MS21 camera screen shot:

4.5. Communications Expansion

Communication to field devices is the backbone that all feeder automation relies on. As the need arises for more distribution automation, our communication networks will be required to expand. This expansion will involve expanding our fibre optic network, increasing the number of spread spectrum radio nodes (both 900 MHZ and 2.4 GHZ) as well as investigating new communication technologies. These new technologies may include secure I/P over the cellular network or Wi-Max solutions.

FACILITY ASSET MANAGEMENT STUDY

Hydro One Brampton's Facility Asset Management Study can be made available upon request.

CHARITABLE DONATIONS

Hydro One Brampton does not make any charitable donations. All charitable donations are made by Hydro One for all subsidiaries. When a request comes in for a donation, it is submitted to Hydro One for their consideration. In accordance with Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued May 27, 2009, the recovery of charitable donations is not allowed for rate setting purposes. Therefore, Hydro One Brampton has not included any charitable donations in the 2011 test year.

Hydro One Brampton does have a sponsorship budget to support local organizations and events. The annual budget for these sponsorships is set at $25,000.

Table 1, below, provides the history of Hydro One Brampton's sponsorships.

Table 1: Hydro One Brampton Sponsorships 2006 - 2011

Requestor	Details	2006 Sponsorships	2007 Sponsorships	2008 Sponsorships	2009 Sponsorships	2010 Budgetted Sponsorships	2011 Estimated Sponsorships
City of Brampton	Development Team Membership	$ 10,000	$ 10,000	$ -	$ -	$ -	
Secondary School Scholarship	Scholarship to one Brampton Secondary School student (essay contest). We advertize the contest in all schools and announce the winner in the local papers and on our bills.	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	
City of Brampton	Sponsor Mayor's Golf Tournament	$ 5,000					
Employee Volunteer Grant program	Sponsorships for teams on which employees participate as per Hydro One rules	$ 550	$ 1,500	$ 2,300	$ 2,000	$ 2,500	
Golf Tournament Sponsorships	This will be for hole sponsorships only, not for foursomes to participate.	$ 400	$ 750	$ 1,050	$ 1,000	$ 1,500	
Electricity Distributors Association	Conference Sponsor (EDIST conference)	$ 500	$ 500	$ 750	$ 788	$ 1,000	
William osler Health Centre Fooundation	Sponsor Annual Gala	$ 7,500	$ -	$ -	$ -	$ -	
City of Brampton	Sponsoring Communities in Bloom/Winterlights programme	$ -	$ 4,000	$ 4,000	$ 5,000	$ 5,000	
Brampton Safe City	Brampton Day - Sponsor for celebration of Brampton designation as a World Safe Community	$ -	$ 5,000	$ -			
Brampton Board Of Trade	President's Gala sponsorship	$ -	$ 1,000	$ 2,200	$ -	$ 1,500	
Roy Taylor Curling Bonspiel	Event Sponsor	$ -	$ 583	$ 1,035	$ 583	$ 600	
Hospital for Sick Kids Foundation	Heatwave Volleyball Tournament Team sponsorship	$ -	$ 400	$ 475	$ 400	$ 500	
CAW Local 1285	Sponsor the Canada Pavillion during Carabram	$ -	$ -	$ 500	$ 500	$ 500	
St John's Ambulance	Sponsor Board of directors luncheon	$ -	$ -	$ 1,000	$ -	$ -	
Municipal Health & Safety Association	Conference Sponsorship (Zero in on Zero)	$ -	$ -	$ 1,000	$ -	$ -	
Brampton Neighbourhood Resource Centre	Sponsored LED Christmas Lights	$ -	$ -	$ 500	$ -	$ -	
Brampton Safe City	Golf Tournament Sponsorship	$ -	$ -	$ 2,500	$ 2,500	$ 2,500	
Brampton Safe City	Award Gala - Sponsorship of an achievement award	$ -	$ -	$ 1,000	$ 1,000	$ 1,000	
Brampton Board of Trade	Sponsor Musical bandfor Santa Claus parade	$ -	$ -	$ 500	$ -	$ 500	
Association of Municipalities of Ontario	2009 Urban Symposium, Courtyard Marriott, Brampton	$ -	$ -	$ -	$ 2,500	$ -	
Brampton Library	One Book One Brampton Campaign	$ -	$ -	$ -	$ 5,000	$ -	
Wellspring Chinguacousy Foundation	Sponsor Christmas lights to decorate their Support Centre	$ -	$ -	$ -	$ 1,000	$ -	
Total		$ 24,950	$ 24,733	$ 19,810	$ 23,271	$ 18,100	$ 25,000

In addition, staff are actively involved in fundraising activities for local charities. In the past, employees have raised money every year through dress down days, raffles, draws and events resulting in the amounts shown in the **Table 2** below. It is expected that employees will continue with fund-raising activities in 2011.

Table 2: Employee Generated Fundraising 2006 - 2009

	2006	2007	2008	2009
Charity Golf Tournament	$51,000	$68,000	$93,321	$91,063
United Way Campaign	$24,641	$27,340	$26,630	$24,100
Charity Committee	N/A	N/A	$6,000	$3,700
CIBC Run for the Cure	$3,411	$1,901	$3,024	$3,000
Big Bike for Heart & Stroke	$2,200	$1,623	$3,883	$2,338
	$81,252	$98,864	$132,858	$124,201

EXHIBIT 4 TAB 3

VARIANCE ANALYSIS

QUALITATIVE VARIANCE ANALYSIS

Table 1 on Schedule 1.1 details all variances between the 2006 Actual and the 2011 Test Year, as well as between the 2009 Most Current Actual and the 2011 test year. A variance analysis for each account that exceeds the materiality threshold of $300,000, which represents the lowest 0.5% of Hydro One Brampton's revenue requirement, is provided below.

2006 ACTUAL VERSUS 2011 TEST YEAR

5005 – Operation Supervision and Engineering

Operation Supervision and Engineering show an increase of $491,268 due to the implementation of an Asset Management Group in 2010. The increase is due to salaries for the additional staffing requirements of the group, including an Asset Management Supervisor, an Asset Maintenance Technician and a Financial Analyst.

5020 – Overhead Distribution Lines & Feeders – Operation Labour

Overhead Distribution Lines & Feeders – Operation Labour shows an increase of $1,013,123 as OM&A under IFRS is higher than CGAAP OM&A due to the reclassification of disallowable costs otherwise included in capital of $993,138.

5040 – Underground Distribution Lines & Feeders – Operation Labour

Underground Distribution Lines & Feeders – Operation Labour shows an increase of $680,207 as OM&A under IFRS is higher than CGAAP OM&A due to the reclassification of disallowable costs otherwise included in capital of $648,457.

5070 – Customer Premises – Operation Labour

Customer Premises – Operation Labour shows an increase of $506,672 primarily due to City Residential Service changes which was new in 2008 and totalled $467,193 in incremental costs for 2008 and 2009.

5150 – Maintenance of Underground Conductors and Devices

Maintenance of Underground Conductors and Devices shows an increase of $388,316. In 2006, U/G primary maintenance was at $530K and has been holding around $780K for 2007-2009. The increase is primary due to our ageing distribution plant. Contractor expenses have increased by $100K due to the increase in primary faults. A new Line Apprentice position was also added in 2009.

5310 – Meter Reading Expense

Meter Reading Expense shows an increase of $359,033 primarily due to utilizing our smart meter readings to replace the manual meter reading for billing purposes and the transfer of all smart meter reading costs from smart metering to account 5310 incorporating all costs associated with the MDMR.

5315 – Customer Billing

Customer Billing shows an increase of $671,973. This is due to 3% salary increases to staff, an increase in postage and stationery costs of $36,000 in 2008 and an additional increase of 2% in the Test Year. Increases in headcount include an additional Customer Service Representative in 2007 and another in the Test Year.

5320 – Collecting

Collecting shows an increase of $543,253 due in part to the salary for a Retailer Support Representative of $61K created in 2008 and additional labour of $31K from construction, utilizing personnel on light duty for collection activities. There is also 1 additional staff or contract personnel in the Bridge Year for residential/commercial disconnections as well as 3% salary increases and budgeted increase for contractor collection activity.

5415 – Energy Conservation

Energy Conservation shows a decrease of $554,211 associated with the spending of CDM monies between 2004 and 2006 associated with third tranche commitments in 2007 and the completion of these expenditures in 2008 as well as additional staffing requirements in 2011 associated with the OPA's latest provincial mandate to reduce demand and energy within the province.

5605 – Executive Salaries and Expenses

Executive Salaries shows an increase of $499,292 primarily due to the creation of a new position for a Vice President of Engineering & Operations as well as salary increases averaging 3% per year.

5610 – Management Salaries and Expenses

Management Salaries and Expenses show an increase of $897,177 primarily due to increases in corporate function and service charges from Hydro One on account of Bill 198 requirements as well as increases in the S/T Incentive Plan. IFRS OM&A is higher than CGGAP OM&A by $189,456 due to the reclassification of disallowable costs otherwise included in capital.

5615 – General Administrative Salaries and Expenses

General Administrative Salaries and Expenses show an increase of $541,845 associated salary increases averaging 3% per year including implementation of International Financial Reporting Standards and increase AS400 Hardware & Maintenance expense as well as addition to staff in 2010 for a Software Developer. IFRS OM&A is higher than CGGAP OM&A by $484,836 due to the reclassification of disallowable costs otherwise included in capital.

5655 – Regulatory Expenses

Regulatory Expenses show an increase of $348,599 largely due to the additional labour costs associated with the regulatory department as well as salary increases averaging 3% per year. A new position for a Regulatory Affairs Supervisor was created in 2007 and a Regulatory Affairs Analyst position was created in 2009. There is also an expected increase in regulatory costs associated with the 2011 cost of service application.

5665 – Miscellaneous General Expenses

Miscellaneous General Expenses show an increase of $492,942. This is due to an Accounting Supervisor added in 2006, increases in salaries to Accounting and Personnel staff averaging 3% per year as well as one additional staff added to the Personnel Department for a Human Resources Manager in the Test Year.

2009 ACTUAL VERSUS 2011 TEST YEAR

5020 – Overhead Distribution Lines & Feeders – Operation Labour

Overhead Distribution Lines & Feeders shows an increase of $1,013,123 as IFRS OM&A is higher than CGGAP OM&A due to the reclassification of disallowable costs otherwise included in capital of $993,138.

5040 – Underground Distribution Lines & Feeders – Operation Labour

Underground Distribution Lines & Feeders shows an increase of $684,654 as IFRS OM&A is higher than CGGAP OM&A due to the reclassification of disallowable costs otherwise included in capital of $648,457.

5065 – Meter Expense

Meter Expense shows an increase of $349,957 mainly associated with Hydro One Brampton's smart metering program. Throughout the implementation of this program, it was decided to focus on installing meters on customers in the parts of the city that would present the least amount of failed meter bases and failed equipment. All questionable areas, those areas that were expected to have a high failure rate, were saved and will be completed in 2010. As a result, an additional $400,000 was budgeted to cover off theses costs in 2010. It was also expected that Hydro One Brampton would be paying approximately $320,000 in software costs associated with the smart metering program once the program was completed. There were no costs for this in 2009. In order to complete the commercial smart meter installations, Hydro One Brampton utilized its own metering crews to install these meters in 2009. As a result, there were only a minimal number of cross phase tests completed in 2009 due to the reallocation of metering crews to the smart metering project. In 2010, it is expected that an additional $100,000 of cross phase testing work will be completed as compared to 2009. The variance in the test year is largely a result the transfer of Smart Metering software cost responsibility from the metering department to the IT department. This is approximately $300,000. The remaining is largely associated with the reduction of failed meter base cost off set by incremental smart metering maintenance costs.

5310 – Meter Reading Expense

Meter Reading Expense shows an increase of $407,808 primarily due to utilizing our smart meter readings to replace the manual meter reading for billing purposes and the transfer of all smart meter reading costs from smart metering to account 5310 incorporating all costs associated with the MDMR.

5315 – Customer Billing

Customer billing shows an increase of $366,211. This is due to 3% wage increases to staff and one additional customer service representative. An increase of 2% in postage and stationery costs is also included.

5320 – Collecting

Collecting costs shows an increase of $310,343 due to 3% wage increases and 1 additional staff for residential/commercial disconnections. We have also budgeted for increased contractor collection activity.

5335 – Bad Debt Expense

Bad Debt Expense shows a decrease of $442,534 primarily due to the one-time large bankruptcies from the auto sector in 2009 ($233,000) that are not expected to re-occur, but the budget allowed for a 20% or $100,000 increase in bad debts from levels seen in 2008.

5610 – Management Salaries and Expenses

Management Salaries and Expenses show an increase of $897,653 primarily due to increases in corporate function and service charges from Hydro One as well as increases in the S/T Incentive Plan. IFRS OM&A is higher than CGGAP OM&A by $189,456 due to the reclassification of disallowable costs otherwise included in capital.

5615 – General Administrative Salaries and Expenses

General Administrative Salaries and Expenses show an increase of $424,172 due to wage increases to IS staff averaging 3% per year and the addition of a Software Developer in 2010. OM&A is higher than CGGAP OM&A by $484,836 due to the reclassification of disallowable costs otherwise included in capital.

5665 – Miscellaneous General Expense

Miscellaneous General Expense shows an increase of $542,717 due to increases in Accounting and Personnel salaries including one additional staff added to the Personnel Department in the Test Year for a Human Resources Manager.

QUANTITATIVE VARIANCE ANALYSIS

Table 1: Quantitative Variance Analysis

		2006 Actuals	2011 Test Year	Variance	Percent Change (%)	2009 Actuals	2011 Test Year	Variance	Percent Change (%)
Operation									
5005	Operation Supervision and Engineering	-	491,268	491,268		225,693	491,268	265,575	118%
5010	Load Dispatching	1,406,760	1,665,079	258,319	18%	1,451,220	1,665,079	213,859	15%
5012	Station Buildings and Fixtures Expense	174,222	213,259	39,037	22%	194,084	213,259	19,175	10%
5014	Transformer Station Equipment - Operation Labour	39,141	24,969	(14,172)	-36%	17,868	24,969	7,101	40%
5015	Transformer Station Equipment - Operation Supplies and	-	-	-		-	-	-	
5016	Distribution Station Equipment - Operation Labour	69,558	90,930	21,372	31%	70,820	90,930	20,110	28%
5017	Distribution Station Equipment - Operation Supplies and	-	-	-		-	-	-	
5020	Overhead Distribution Lines & Feeders - Operation Labour	93,447	1,106,570	1,013,123	1084%	112,317	1,106,570	994,253	885%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and	45,196	188,254	143,058	317%	73,928	188,254	114,326	155%
5030	Overhead Subtransmission Feeders - Operation	-	-	-		-	-	-	
5035	Overhead Distribution Transformers - Operation	80,309	114,895	34,586	43%	122,107	114,895	(7,212)	-6%
5040	Underground Distribution Lines and Feeders - Operation Labour	174,395	854,602	680,207	390%	169,948	854,602	684,654	403%
5045	Underground Distribution Lines and Feeders - Operation Supplies	-	-	-		-	-	-	
5050	Underground Subtransmission Feeders - Operation	-	-	-		-	-	-	
5055	Underground Distribution Transformers - Operation	65,251	118,761	53,510	82%	95,252	118,761	23,509	25%
5065	Meter Expense	882,302	1,041,299	158,997	18%	691,342	1,041,299	349,957	51%
5070	Customer Premises - Operation Labour	261,975	768,647	506,672	193%	493,862	768,647	274,785	56%
5075	Customer Premises - Materials and Expenses	720	-	(720)	-100%	(449)	-	449	-100%
5085	Miscellaneous Distribution Expense	41,608	125,609	84,001	202%	64,689	125,609	60,920	94%
5090	UG Dist Lines & Fdrs - Rental	270	-	(270)	-100%	-	-	-	
5095	Overhead Distribution Lines and Feeders - Rental Paid	15,681	50,850	35,169	224%	32,361	50,850	18,489	57%
Sub-Total		**3,350,836**	**6,854,992**	**3,504,156**		**3,815,041**	**6,854,992**	**3,039,951**	
Maintenance									
5105	Maintenance Supervision and Engineering	41,805	187,613	145,808	349%	56,158	187,613	131,455	234%
5110	Maintenance of Building and Fixtures - Distribution Station	5,782	4,170	(1,612)	-28%	861	4,170	3,309	384%
5112	Maintenance of Transformer Station Equipment	78,634	112,531	33,897	43%	73,793	112,531	38,738	52%
5114	Maintenance of Distribution Station Equipment	145,226	160,019	14,793	10%	104,500	160,019	55,519	53%
5120	Maintenance of Poles, Towers and Fixtures	252,041	456,622	204,581	81%	169,120	456,622	287,502	170%
5125	Maintenanceof Overhead Conductors and Devices	530,994	539,003	8,009	2%	483,471	539,003	55,532	11%
5130	Maintenance of Overhead Services	198,931	198,230	(701)	0%	153,708	198,230	44,522	29%
5135	Overhead Distribution Lines and Feeders - Right of Way	196,221	222,534	26,313	13%	249,969	222,534	(27,435)	-11%
5145	Maintenance of Underground Conduit	-	-	-		-	-	-	
5150	Maintenance of Underground Conductors and Devices	925,401	1,313,717	388,316	42%	1,047,644	1,313,717	266,073	25%
5155	Maintenance of Underground Services	609,676	793,977	184,301	30%	764,770	793,977	29,207	4%
5160	Maintenance of Line Transformers	22,591	23,087	496	2%	32,768	23,087	(9,681)	-30%
5175	Maintenance of Meters	16,676	24,000	7,324	44%	22,463	24,000	1,537	7%
Sub-Total		**3,023,980**	**4,035,503**	**1,011,523**	**33%**	**3,159,226**	**4,035,503**	**876,277**	
Billing and Collecting									
5305	Supervision	193,674	314,151	120,477	62%	220,033	314,151	94,118	43%
5310	Meter Reading Expense	732,331	1,091,363	359,033	49%	683,555	1,091,363	407,808	60%
5315	Customer Billing	1,775,757	2,447,720	671,963	38%	2,081,509	2,447,720	366,211	18%
5320	Collecting	539,546	1,082,799	543,253	101%	772,456	1,082,799	310,343	40%
5325	Collecting - Cash Over and Short	-	-	-		1	-	(1)	-100%
5330	Collection Charges	12,654	10,710	(1,944)	-15%	8,305	10,710	2,405	29%
5335	Bad Debt Expense	338,941	525,300	186,359	55%	967,834	525,300	(442,534)	-46%
5340	Miscellaneous Customer Accounts Expense	182,662	184,620	1,958	1%	164,230	184,620	20,390	12%
Sub-Total		**3,775,564**	**5,656,663**	**1,881,099**	**50%**	**4,897,921**	**5,656,663**	**758,742**	
Community Relations									
5405	Supervision	13,508	115,000	101,492	751%	93,878	115,000	21,122	22%
5410	Community Relations - Sundry	199,391	255,000			211,285	255,000	43,715	21%
5415	Energy Conservation	669,211	115,000	(554,211)	-83%	-	115,000	115,000	
5420	Community Safety Program	-	25,000	25,000		-	25,000	25,000	
5425	Misc Customer Service and Informational Expenses	136,340	130,000	(6,340)	-5%	57,975	130,000	72,025	124%
Sub-Total		**1,018,450**	**640,000**	**(434,059)**	**-43%**	**363,138**	**640,000**	**276,862**	
Administrative and General									
5605	Executive Salaries and Expenses	442,941	942,233	499,292	113%	704,355	942,233	237,878	34%
5610	Management Salaries and Expenses	1,165,817	2,062,994	897,177	77%	1,165,341	2,062,994	897,653	77%
5615	General Administrative Salaries and Expenses	1,006,434	1,548,279	541,845	54%	1,124,107	1,548,279	424,172	38%
5620	Office Supplies and Expenses	182,263	-	(182,263)	-100%	-	-	-	
5625	Administrative Expense Transferred Credit	-	-	-		-	-	-	
5630	Outside Services Employed	142,112	248,500	106,388	75%	117,154	248,500	131,346	112%
5635	Property Insurance	(2,533)	-	2,533	-100%	-	-	-	
5640	Injuries and Damages	190,551	188,700	(1,851)	-1%	129,463	188,700	59,237	46%
5645	Employee Pensions and Benefits	(194,909)	-	194,909	-100%	-	-	-	
5655	Regulatory Expenses	696,401	1,045,000	348,599	50%	838,051	1,045,000	206,949	25%
5660	General Advertising Expenses	13,142	15,000	1,858	14%	8,765	15,000	6,235	71%
5665	Miscellaneous General Expenses	945,520	1,438,462	492,942	52%	895,745	1,438,462	542,717	61%
5670	Rent	-	-	-		-	-	-	
5675	Maintenance of General Plant	415,617	568,152	152,535	37%	561,626	568,152	6,526	1%
5680	Electrical Safety Authority Fees	46,710	62,250	15,540	33%	56,497	62,250	5,753	10%
5685	IMO Fees & Penalties	2,278	-	(2,278)	-100%	-	-	-	
5695	OM&A Contra Account	(65,527)	-	65,527	-100%	-	-	-	
Sub-Total		**4,986,820**	**8,119,570**	**3,132,750**	**63%**	**5,601,103**	**8,119,570**	**2,518,467**	**45%**
Total OM&A Expenses		16,155,651	25,306,728	9,095,468	56%	17,836,429	25,306,728	7,470,299	42%

EXHIBIT 4 TAB 4

EMPLOYEE COMPENSATION BREAKDOWN

COMPENSATION OVERVIEW

Hydro One Brampton compensation plan is designed to attract, retain and motivate its internal talent while also ensuring external competitiveness in the marketplace. It is a combination of both cash and non-cash rewards, including base wages, incentive compensation (for Executives, Management and Non-Union staff), and benefits, including the OMERS pension.

IBEW & CAW COMPENSATION

Hydro One Brampton has collective agreements with the Canadian Auto Workers Union (CAW) and the International Brotherhood of Electrical Workers (IBEW), which can be modified only through negotiations. Compensation of IBEW- and CAW-represented employees is negotiated through the collective bargaining process. In a heavily unionized environment, the employer has limited ability to reduce compensation costs per employee, particularly when a pending shortage of skilled labour in the industry is likely to put pressure on an increase in wages. However, in light the Ontario Government's Provincial budget plan (delivered March 25, 2010) to implement two-year wage freezes for public sector wages for both unionized and non-union employees, base wage compensation will not increase in the short-term (this plan is expected to be in place until 2013).

MANAGEMENT COMPENSATION

Following a 2006 review by the Hay Group, Hydro One Brampton's Management Compensation Plan was re-designed around a structure comprised of eight (8) pay bands.

Each management position is assigned to a salary band according to the accountabilities, size and complexity of the job. An employee's base salary within the pay band depends upon their expertise relative to the requirements of the job. Management compensation was reviewed once again in 2010 by the Hay Group. The review included a comparison of Hydro One Brampton base rates and short-term incentives with eight (8) other Ontario Local Distribution Companies (LDC's) in the Hay database. Base wages, incentives and total compensation were compared to the other LDC's and compensation was set at the 50th percentile of the Comparator group. As a result of the Provincial directive, job rates were not changed.

Management wages are expected to be affected by the Provincial directive until 2012. As part of the total compensation package, Management is eligible for short-term incentive compensation (please see Exhibit 4, Tab 4, Schedule 9 for more details on the Incentive Plan).

TOTAL COMPENSATION COSTS

Table 1, below, outlines the total annual compensation costs and average compensation levels per full time employee from the last Board approved rebasing year (2006) and levels from 2009 to 2011.

Table 1: Total Annual Compensation Costs & Average Compensation Per Full-Time Employee Equivalent

Total Annual Compensation & Average Compensation Per Full Time Employee Equivalent (FTEE)*				
	2006 OEB Approved (Actual)	2009 (Actual)	2010 (Projected)	2011 (Projected)
Executive	400,667	719,210	745,084	751,084
Management	2,948,323	4,222,883	4,608,979	4,704,442
Non-Union	1,123,141	1,619,368	2,220,235	2,774,301
Union	10,421,428	12,649,125	12,664,053	13,514,069
Total Compensation	14,893,559	19,210,586	20,238,351	21,743,896
Number of FTEE's	183	211	225	231
Average Compensation per FTEE	**$81,386**	**$91,045**	**$89,948**	**$94,129**

*At December 31st for each listed year.

EMPLOYEE HEADCOUNT COST DRIVERS

OVERVIEW

At December 31, 2009, Hydro One Brampton employed 204 full-time staff, as shown in **Table 1** below. Hydro One Brampton is made up of three categories of regular full-time employees:

CAW Represented Staff: The CAW is an industrial union that represents trades, operators, and technicians. The majority of the CAW-represented employees in Hydro One Brampton have post-secondary education, predominately at the community college level. These include Hydro One Brampton Electrical Maintainers, Line Maintainers, Operators, Technicians, Survey & Inspection, Drafting and Purchasing staff. The CAW represents 108 full-time staff at Hydro One Brampton, which comprises 52% of the total workforce (at December 31, 2009). This group works 40 hours per week.

IBEW Represented Staff: The IBEW represents some 725,000 members in construction, utilities, manufacturing, telecommunications, broadcasting, railroads and government. Specifically, at Hydro One Brampton, the IBEW represents 41 full-time Administrative and Clerical staff. The majority of the IBEW-represented employees in Hydro One Brampton have a minimum Grade 12 education and some have post-secondary and post-graduate education. These include positions in Accounting, Energy Services, Communications, and Customer Service. The majority of this unit work a 35 hour work week with the exception of two individuals in the Energy Services department who work 40 hours per week.

Management Staff: Management staff is excluded from representation because they carry out managerial duties or work on confidential matters. Included in this category are Executives, Managers, Supervisors, Executive Assistant, Payroll Officer, GIS/Operations Analyst, Operations Analyst, Project Engineer, Accounting, Information Technology, Regulatory, and Human Resources staff. All management staff work 40 hours per week. There are 55 full-time staff within this group (December 31, 2009).

For the purposes of this application, Management staff will be broken down into three distinct groups:

- Executives: The President & CEO, and Vice-Presidents;
- Management: Managers and Supervisors;
- Non-Union: Executive Assistant, Payroll Officer, GIS/Operations Analyst, Operations Analyst, Project Engineer, Accounting, Information Technology, Regulatory, and Human Resources staff.

Hydro One Brampton also hires contract, student and temporary staff to bridge short-term gaps created by approved leaves of absence, vacant positions, special projects and vacation periods. These categories have been included in Hydro One Brampton's definition of Full-Time Equivalent Employee. The length of service per FTEE is prorated for any time served that is less than one full year. It is projected that Hydro One Brampton will have additions of seven part-time staff (which includes contract, students and temporary staff) in both the 2010 bridge year and the 2011 test year.

Hydro One Brampton, through its policies and practices, promotes a productive and efficient workforce that places a strong emphasis on customer service. **Table 1,** below provides an overview of the number of Full-Time Equivalent Employees from the time of the last OEB Board approved rebasing year to the 2011 test year and the corresponding growth in Hydro One Brampton's customer base over the same period.

Table 1: Full Time Equivalent Employee Headcount and Corresponding Customer Base Growth

	OEB Approved			**Historical Year (Bridge Year -1)**	**Bridge Year**	**Test Year**
Year	2006	2007	2008	2009	2010	2011
Number of Employees (FTEE's)						
Executive	2	2	3	3	3	3
Management	27	33	33	34	35	35
Non-Union	16	21	22	25	28	30
Union	138	146	149	149	159	163
Total	**183**	**202**	**207**	**211**	**225**	**231**
Customer Growth						
Number of Customers	110,369	126028	129524	131,029	132429	133890
Increase (decrease) %	-	*14.2%***	2.8%	1.2%	1.2%	1.1%

*At December 31, 2009 **Percentage represents a 3-year increase as 2006 OEB Approved is 2004 Actual data.

With a steady growth in customer base year-over-year, the organization has endeavoured to keep pace by gradually increasing staffing each year in order to maintain its levels of efficiency, productivity and customer service (customer base has increased by 21% and employee headcount has increased by 26% from 2004 [2006 OEB Approved] to 2011). New programs and succession planning also account for additional hiring during this period. However, like many other local utilities in the electricity sector, Hydro One Brampton faces a great challenge in the years to come with respect to its staffing and workforce planning due to an aging workforce, a shortage of specialized skills in the industry and a highly competitive labour market.

Currently, the average age of all employees is 46, and 41% of employees are 50 years of age or older. By December 31, 2011, approximately 98 employees representing 48% of Hydro One Brampton's current full-time population will be 50 years old or older, and by December 31, 2016, that percentage will increase to 68%. At the end of the test year, 12% of Hydro One Brampton's current staff will be eligible for an undiscounted retirement. **Table 2** provides a summary of the organization's employee age demographics:

Table 2: Age Demographics for Full-Time Employees

Age Category	*Number of Full Time Employees*	*% of Total*
>50	84	41%
40-49	75	37%
30-39	29	14%
<30	16	8%
Total	**204**	**100%**

On the following page, **Figure 1** provides a summary of years of service for Hydro One Brampton's current employee population and projected years of service in the test year (2011) and after a five-year period (2016):

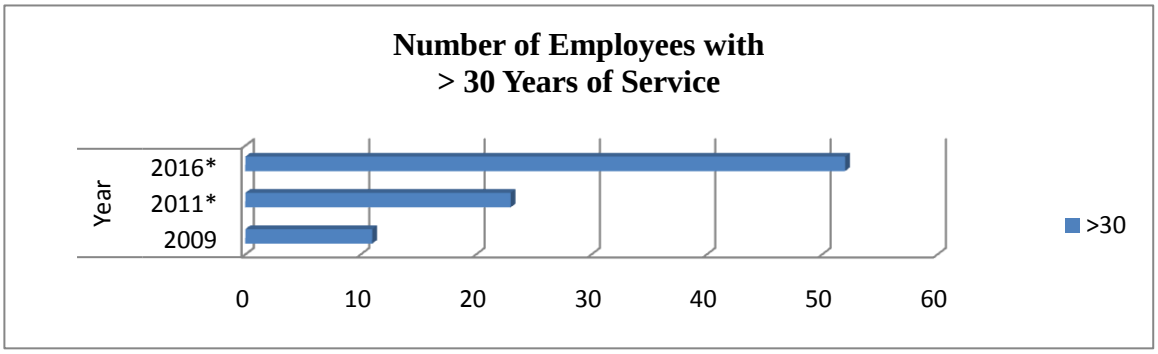


Figure 1: Employee Years of Service for Full-Time Employees (2009, 2011 and 2016)

*Projected based on the current employee population at December 31, 2009

Table 3 below summarizes Full-Time Employee Demographics with Age and Years of Service for Key Groups:

Table 3: Employee Demographics Average Age and Years of Service*

Group	Average Age	Average Years of Service
Management (Management & Supervisors)	50	18
Engineering & Operations	47	17
Information Technology	49	15
Customer Service	47	12
Financial Services	43	9
Energy Services	42	8
Lines	41	16

*At December 31, 2009

Over the next five-year period, the percentage of employees with 30 or more years of service will increase approximately five times. Key vulnerabilities exist in Sr. Management (Managers Group), Lines, and in Information Technology specialty areas; as a large percentage of individuals in these areas are approaching or are over the age of 50 and have 30 or more years of service and as such will be eligible for retirement within the next five years.

It is also anticipated that “Green Energy” and infrastructure investment initiatives will increase the demand for electricity energy specialists which will pose new challenges with respect to sourcing candidates with these particular skill sets. These problems are further exacerbated by the highly competitive labour market.

SUCCESSION PLANNING

In order to deal with the impending changes in employee demographics, known challenges associated with human resources have been identified and plans are being developed for mitigating this risk. The Company has developed a succession plan for key positions in the organization and will be ensuring that this plan is kept up to date. Hydro One Brampton's Senior Management team meets on an annual basis to discuss staffing requirements. In their decision-making, they consider factors such as customer growth, new development of programs, succession planning and changes to organizational structure.

In working with Human Resources to staff the organization, main considerations include the amount of work to be done, the nature of the work and the skills required, as well as the most cost effective means of acquiring those skills within the constraints of the collective agreements. However, the changes in some of Hydro One Brampton's programs and continued customer growth will add additional challenges, given the tight competition for labour and electricity sector professionals.

RECRUITMENT PROGRAMS

To help address the expected wave of retirements in the Company's critical trades, HOBNI's parent company, Hydro One Networks Inc. has proactively partnered with universities and colleges to develop curriculum that educates students in areas where the Company may face a shortage of skilled professionals and trades people. HONI has taken a leadership role in support for power system engineering programs, assisting in developing on-line power system engineering programs. They also hold the Chair of the Electricity Sector Council, a Canada-wide organization composed of employers, bargaining agents, educators, associations and government representatives designed to deal with the skills shortage in the industry. The Council's primary goal is to increase the number of qualified individuals for employment within the industry. HONI also holds the Chair of the Canadian Electrical Association's Human Resources Committee (CEA). Its mandate is to assist the CEA Board in its oversight of HR support and development for the industry, monitor and report on emerging HR issues and share best practices and work collaboratively in development of mutually beneficial initiatives.

Hydro One Brampton benefits from the partnership that HONI has developed with the universities and colleges as it has promoted the Hydro One name and its programs.

Hydro One Brampton has also developed a close relationship with the local colleges and specifically with Cambrian College in Sudbury, in the progressive hiring of co-op students from their Powerline Technician Program. This program has provided Hydro One Brampton with talented, trained candidates for co-operative positions in the Lines trade which has allowed us an opportunity to assess the student's "fit" and long-term potential with the company. Once hired, experience shows that these former co-op students have a shorter learning curve than other new hires with no previous Hydro One Brampton experience. Hydro One Brampton also participates in various other co-op programs with the neighbouring colleges and universities.

SUMMARY

Despite an ongoing focus on efficiency and productivity, Hydro One Brampton's employee headcount will continue to increase. In 2004 (the historic test year used to establish distribution rates on a cost of service basis in 2006) Hydro One Brampton had 183 full-time equivalent employees. In 2011, the employee headcount is projected at 231, which represents a 26% increase in staffing levels over a five-year period. The increase in headcount has been primarily the result of succession planning, customer growth, and new programs. Hydro One Brampton will continue to respond proactively to the impending shortage of skilled workers in the utility by hiring well in advance of expected retirements because of the long learning curves required for competent performance of highly skilled jobs.

WAGE PRICE COST DRIVERS

Annual adjustments to base wages for employees represented by the IBEW and CAW are made in compliance with collective bargaining agreements. The current collective agreements for both bargaining units run from April 1, 2008 and expire on March 31, 2011. In order to maintain Hydro One Brampton's internal pay equity, inflation adjustments to the base wages of Executives, Management and Non-union staff are on average made at levels consistent with those negotiated for bargaining unit staff. **Table 1** below summarizes the annual base wage inflation adjustments for a five-year period (from 2007-2011 inclusive). The 2011 adjustment shown for bargaining unit staff is as required under the current collective agreement and expires March 31st of that year. The 2011 adjustment for Executives, Management and Non-union staff is projected:

Table 1: Annual Base Wage Inflation Adjustments

Year	2007	2008	2009	2010	2011*
Bargaining Unit Staff – CAW & IBEW (effective April 1st)	3.00%	3.00%	3.00%	3.00%	0%
Executives, Management & Non-Union Staff (effective January 1st)	Avg. 2.8%	Avg. 4.0%	Avg. 3.0%	Avg. 2.0%	Avg. 0%

* 2011 inflation adjustments for Management & Non-Union staff is projected. 2011 inflation adjustments for Bargaining Unit Staff expire March 31, 2011. ** Includes Progressions.

For bargaining unit staff, annual inflation adjustments have increased base wages by a cumulative amount of approximately 12% since 2007 (to 2011). For Executives, Management and Non-Union staff, the increase is approximately 11.8%. The union contracts expire on March 31, 2011. Projected base wage adjustments for 2011 have been set at 0% due to the Ontario Government's provincial budget plan (delivered March 25, 2010) to implement a two-year wage freeze for public sector wages for both unionized and non-union employees. This plan is expected to be in place until 2013.

In addition to annual inflation adjustments, the wages of eligible employees are adjusted for progressions within the pay bands for their respective positions. For CAW and IBEW employees, the collective agreement determines the progression (on average, the progression periods range from every six months to once per year). For Executives, Management and Non-

union staff, progressions are based on performance and vary across the individual departments (these progressions typically take place on an annual basis). In future, as more long-service employees exit the organization and their positions are filled by new and potentially junior-level employees, the impact of progression adjustments will have a greater impact on total compensation. The two-year wage freeze will not have an impact on employees who will still be progressing within their pay bands, new employees or current employees who are transferring to a new position and expected to progress within that position.

PAY EQUITY ADJUSTMENTS COST DRIVERS

Hydro One Brampton last reviewed its Pay Equity Plan in late 2006. The review ensured that female-dominated job classifications were fairly compensated in relation to similarly ranked male-dominated job classifications, as per its obligation under the Pay Equity Act.

The review was completed most recently for IBEW positions as this bargaining unit is predominantly female. The job evaluation plan was finalized October 12, 2007. The re-evaluations resulted in adjustments to two positions and the base wages of three employees. The adjustments were paid retroactively for the period January 1, 2007 to September 14, 2007. The annual impact of the changes was $12,325.87 in 2007. No further adjustments were made for the period 2008 - 2010 and there are no adjustments projected for 2011.

BENEFITS PROGRAMS COST DRIVERS

BENEFITS PACKAGE OVERVIEW

Hydro One Brampton offers its employees a comprehensive and competitive benefits package which includes Extended Health & Dental coverage, Life Insurance, Long-Term Disability coverage, and a company-sponsored defined benefit retirement plan (OMERS). This benefits package is consistent across all groups (CAW, IBEW and Management) with only slight differences in LTD maximums. A monthly car allowance is also provided as a benefit to Managers and Executives. Hydro One Brampton also contributes the employer portion of the Employers Health Tax, Canada Pension Plan, Employment Insurance and the Workers Safety Insurance Board premiums.

The following tables provide data on annual benefits costs:

Table 1: Average Annual Benefits ($) per FTEE

Average Yearly Benefits Per FTEE				
	OEB Approved (2006)	**Historical Year (2009)**	**Bridge Year (2010)**	**Test Year (2011)**
Executive	34,146	39,967	44,000	46,000
Management	19,259	21,560	23,029	24,143
Non-Union	16,546	16,238	13,619	13,043
Union	13,810	14,786	15,233	15,571
Total	**15,034**	**16,255**	**16,725**	**17,058**

POST-RETIREMENT BENEFITS

Hydro One Brampton continues to pay Life Insurance premiums for retirees. In addition to this, employees of Hydro One Brampton are given the option once they retire, to continue on the Extended Health & Dental plan up to the age of 65. They are required to pay for 50% of the premiums, while Hydro One Brampton pays the balance. In 2004, twenty-nine (29) early retirees were enrolled in the post-retirement Extended Health & Dental benefit plan. In 2009 there were seventeen (17) early retirees enrolled in this plan. **Table 2** shows post-retirement

benefit costs which include Life Insurance and Post-Retirement Extended Health & Dental premiums:

Table 2: Post-Retirement Benefit Costs

Post-Retirement Benefit Costs				
	OEB Approved (2006)	**Historical Year (2009)**	**Bridge Year (2010)**	**Test Year (2011)**
Early Retirees	150,382	137,386	142,562	147,957

PENSION PLAN

Hydro One Brampton is a participant in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. The plan is a contributory, defined benefit pension plan whose members comprise represented employees of the CAW, IBEW, non represented management employees, employee pensioners and beneficiary pensioners. Hydro One Brampton contributes 50% of the OMERS premiums. **Table 3** below shows OMERS Pension Premiums:

Table 3: OMERS Pension Premiums ($):

OMERS Premiums				
	OEB Approved (2006)	**Historical Year (2009)**	**Bridge Year (2010)**	**Test Year (2011)**
Premiums Paid	751,304	1,104,072	1,230,000	1,264,000

Hydro One Brampton assumes a projection of a 3% increase in OMERS premiums in 2010 based on an average annual increase in wages, and a 0% increase in 2011 based on the projected base wage adjustments being set at zero (0%) due to the two-year wage freezes for public sector wages for both unionized and non-union employees implemented by the Ontario Government.

SUMMARY

Benefits have increased by 21% over the 2006-2011 period. In particular, Health and Dental benefit premiums have been projected to increase by 5% in 2011. Increases in benefit premiums are partly a result of increased headcount but also reflect both the effect of inflation and the effect of an aging workforce at Hydro One Brampton as the cost and utilization of health care services and drugs will increase.

OVERTIME COST DRIVERS

Company overtime is predominantly paid to union staff and selected management staff. Management overtime stems mainly from staff required to be on-call and special project work and accounts for only 7% of total overtime worked. Union overtime accounts for 93% of total overtime and this is comprised of about 50% emergency work (storms, damage or outages) and 50% planned work due to increased construction work. The collective agreement outlines specific rules for each bargaining unit for overtime usage and payouts. For CAW staff, overtime is paid at double-time and hours may be accumulated in a bank to a maximum of 80 hours (or 40 overtime hours) per calendar year. For IBEW employees, overtime is also paid at double-time and a maximum of 70 hours may be banked per calendar year. Management staff are paid double-time for all approved overtime. Overtime usage is monitored regularly to ensure that it is used effectively and efficiently. Actual and projected annual overtime cost data is provided in the following table.

Table 1: Average Yearly Overtime

Compensation - Average Yearly Overtime				
	Last Rebasing (2006)	**Historical Year (2009)**	**Bridge Year (2010)**	**Test Year (2011)**
Executive	-	-	-	-
Management	7,903	5,078	5,442	5,139
Non-Union	2,176	1,579	1,692	1,598
Union	5,745	7,527	8,067	7,619
Total	**5,729**	**6,613**	**7,087**	**6,693**

Levels of overtime decreased slightly for the Management and Non-Union groups from the 2006 rebasing year to 2009. This decrease was a result of cut-backs and stricter rules in overtime allowance for these particular groups. Average overtime for Union staff increased over this period and this was due to increasing construction projects. Overtime is forecasted to increase in 2010 from levels recorded in 2009 and then slight decreases are forecasted for 2011.

COMPENSATION COST RECONCILIATION

2006 - 2011

The table below summarizes the significant changes in employee compensation from 2006 OEB Board Approved to forecast Test Year 2011:

Table 1: Total Compensation Reconciliation

	$000
2006 Board Approved Total Compensation	14,894
Changes due to:	
- Increased Headcount	1,422
- Cumulative Wage Inflation and Progression	3,508
- Pay Equity Adjustments	12
- Increased Benefit Costs	1,246
- Overtime Costs	267
- Incentive Compensation Costs	395
Projected 2011 Compensation	21,744

EMPLOYEE ADDITIONS FOR 2010 BRIDGE AND 2011 TEST YEAR

Table 1, below, outlines the Hiring Schedule for each quarter for the bridge year (2010) and test year (2011). Under Position Rationale, 'P' indicates a New Program, 'R' indicates a Replacement Position, 'S' indicates an addition due to Succession Planning, 'W' indicates a position added due to Increased Workload and 'C' indicates a Completion of Program. Bridge (2010) and test year (2011) Hiring Schedule

The following table summarizes a brief position description for the 2011 Employee Additions & Deletions:

Table 1: Bridge (2010) and Test Year (2011) Hiring Schedule

POSITION	No. of Hires	Number of Hires by Quarter								Position Rationale
		2010				2011				
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
Accounts Receivable Analyst	1		1							R
Assistant Supervisor – Customer Accounts	1			1						W
Building General Helper	1		1							W
Credit Representative	1					1				W
Customer Accounts Representative	2	1				1				W
Drafting Supervisor	1	1								R
Draftsperson	1		1							R
Engineering Technician	2	1	1							R (1), P (1),
Fleet Mechanic	1		1							S,W
Health, Safety & Environment Coordinator	1					1				S,W
Line Apprentice	3			2				1		S
Human Resources Manager	1						1			S,W
Conservation & Demand Management (CDM) Representative	1						1			W
Outage Planning Coordinator	1		1							W
Project Engineer	2		1				1			S
(Smart Metering Supervisor)	-1								-1	C
Software Developer	1		1							S,W
TOTAL:	**18**	**3**	**8**	**3**	**0**	**3**	**3**	**1**	**-1**	

The following table summarizes a brief position description for the 2011 Employee Additions:

Table 2: 2011 Employee Additions Descriptions

2011 EMPLOYEE ADDITIONS	DESCRIPTION
Credit Representative	• Analyzes and manages overdue residential and commercial accounts to execute appropriate action to collect monies owing to Hydro One Brampton, in a timely and efficient manner. Assesses risk factors and analyzes customer's ability to pay. Requests security deposits on new or delinquent accounts. Maintains security deposits and customer credit information.
Customer Accounts Representative	• Answers customer account inquiries. Prepares billing data and reviews edits. Processes billings and updates records. Prepares billing adjustments as required. Follow-up activities on accounts.
Health Safety and Environment Coordinator	• Ensures that the Health, Safety & Environment (HSE) department continues to be capable of adequately supporting ongoing HSE initiatives.
Apprentice Lineperson	• Maintenance and construction of overhead and underground distribution lines.
Human Resources Manager	• Accountable for Human Resources and Labour Relations functions. Responsible for negotiations.
Conservation & Demand Management (CDM) Representative	• Accountable for implementing Conservation & Demand Management (CDM) programs. Will work with customers to improve energy efficiency. Implements new (CDM) initiatives separate from OPA programs. Interfaces with external organizations to promote energy efficiency.
(Smart Metering Supervisor)	• Smart Metering Program to end in 2011. Position will be eliminated.
Project Engineer	• Accountable for the certification of Engineering, Technical Service and other department construction projects as required by Ontario Regulation 22/04. This will include deviation of approval for construction projects and the construction verification process. Also accountable for special projects as assigned to provide technical input in the form of design, review or implementation.

INCENTIVE COMPENSATION

MANAGEMENT INCENTIVE

Hydro One Brampton's Executives, Management and Non-Union employees are eligible to receive short-term incentive compensation. The compensation paid under the plan is determined by two components: Corporate performance measures and individual performance measures. This incentive pay plan is variable and as such, reflects differences in corporate and individual performance year-to-year.

The short-term incentive plan is first activated by achieving corporate financial objectives which are established at the beginning of each fiscal year. The corporate financial objectives are outlined in a Corporate Scorecard. The 2010 Scorecard is attached as Schedule 9.2 of this Tab for reference. Full payment of the short term incentive is achievable only if corporate goals are met and awards are reduced to the individual portion when corporate goals are not met. Hydro One Brampton's performance based philosophy ensures that rewards are appropriately aligned with the strategic direction of the Company. Individual performance in Hydro One Brampton's plan is measured against a balanced scorecard of employee's performance in each of four categories:

- Financial
- Customer Commitment
- Business Excellence
- Organizational Strength

Incentive pay is then calculated based on a combination of Hydro One Brampton's corporate objectives and the employee's individual performance balanced scorecard results. The individual performance scores are then adjusted to a Bell curve to ensure proper distribution of incentives. The calculation of an individual's short term compensation will depend on whether targets are met or exceeded and the payout is a percentage of the individual's base salary based on the position level (President and CEO, Manager, Supervisor, etc.). The payout percentages have been determined through an assessment by Hay Consultants of compensation practices in the target market. The short term incentive plan payment schedule is summarized in **Table 1** on the following page.

Table 1: Short Term Incentive Plan Payment Schedule

Short-Term Incentive Plan Payment Schedule			
		Payout	
Position	*Corporate/ Individual Measures*	*Meet Targets*	*Exceed Targets*
President & CEO	40/60	Up to 25%	Up to 37.5%
Vice Presidents	30/70	Up to 20%	Up to 30%
Managers	25/75	Up to 15%	Up to 22.5%
Supervisors	25/75	Up to 10%	Up to 15%
All Other Non-Union Staff	20/80	Up to 5%	Up to 7.5%

In summary, Hydro One Brampton's management compensation principles include linking compensation to the achievement of corporate goals and individual performance and providing incentive pay on an annual basis and based on a thorough performance management system. Hydro One Brampton believes that its short-term incentive program meets both of these principles in a cost-effective manner. The link between the performance factors and the organization's strategic goals ensures that performance is driven by the need for a safe workplace, customer focus, reliability, financial performance and employee and shareholder relations. These together help create a more efficient and high-performance work environment.

IBEW & CAW INCENTIVE

In 2002, an IBEW Short-Term-Incentive Plan was introduced and ran for the term of that Collective Agreement (April 1, 2002-March 31, 2005). The final balance for that plan was paid out in December of 2004. The plan was based on achievement of a Corporate Net Income target as well as individual performance targets. This plan was terminated in the collective bargaining process the following year. The final balance in 2004 (2006 OEB Approved) is noted in the table below. The IBEW and CAW have decided against performance incentives and therefore there are no incentives outlined in the current Collective Agreements.

AVERAGE ANNUAL INCENTIVE

Table 2: Average Annual Incentive Compensation

Average Annual Incentive Compensation				
	2006 OEB Approved	**Historical Year (2009)**	**Bridge Year (2010)**	**Test Year (2011)**
Executive	34,000	44,567	45,942	45,942
Management	6,278	10,978	11,642	11,815
Non-Union	2,250	3,100	5,214	6,089
Union	652	-	-	-
Total:	**6,667**	**10,630**	**12,354**	**12,571**

EMPLOYEE COSTS

The following table outlines in detail FTEE costs:

Table 1: FTEE Costs

	OEB Approved	Historical Year (Bridge Year -1)	Bridge Year	Test Year
Year	2006	2009	2010	2011
Number of Employees (FTEE's including Part-Time)				
Executive	2	3	3	3
Management	27	34	35	35
Non-Union	16	25	28	30
Union	138	149	159	163
Total:	183	211	225	231
Number of Part-Time Employees				
Executive	-	-	-	-
Management	-	-	-	-
Non-Union	5	7	7	7
Union	-	-	-	-
Total:	5	7	7	7
Total Salary and Wages				
Executive	332,375	599,308	613,084	613,084
Management	2,428,323	3,489,836	3,802,979	3,859,442
Non-Union	941,133	1,359,568	1,934,235	2,474,301
Union	8,515,684	10,445,953	10,242,053	10,976,069
Total:	12,217,515	15,894,665	16,592,351	17,922,896
Total Benefits				
Executive	68,292	119,902	132,000	138,000
Management	520,000	733,047	806,000	845,000
Non-Union	182,008	259,800	286,000	300,000
Union	1,905,744	2,203,172	2,422,000	2,538,000
Total	2,676,044	3,315,921	3,646,000	3,821,000
Total Compensation (Salary, Wages, & Benefits)				
Executive	400,667	719,210	745,084	751,084
Management	2,948,323	4,222,883	4,608,979	4,704,442
Non-Union	1,123,141	1,619,368	2,220,235	2,774,301
Union	10,421,428	12,649,125	12,664,053	13,514,069
Total	14,893,559	19,210,586	20,238,351	21,743,896
Compensation - Average Yearly Base Wages				
Executive	132,187	155,203	158,420	158,420
Management	78,919	90,060	97,015	100,790
Non-Union	56,128	51,464	61,723	74,591
Union	57,090	64,565	64,415	67,545
Total	61,047	68,410	70,834	74,595
Compensation - Average Yearly Overtime				
Executive	-	-	-	-
Management	7,903	5,078	5,442	5,139
Non-Union	2,176	1,579	1,692	1,598
Union	5,745	7,527	8,067	7,619
Total	5,729	6,613	7,087	6,693
Compensation - Average Yearly Incentive Pay				
Executive	34,000	44,567	45,942	45,942
Management	6,278	10,978	11,642	11,815
Non-Union	2,250	3,100	5,214	6,089
Union	652	-	-	-
Total	6,667	10,630	12,354	12,571
Compensation - Average Yearly Benefits				
Executive	34,146	39,967	44,000	46,000
Management	19,259	21,560	23,029	24,143
Non-Union	16,546	14,433	13,619	13,043
Union	13,810	14,786	15,233	15,571
Total	15,034	16,255	16,725	17,058
Total Compensation	14,893,559	19,210,586	20,238,351	21,743,896
Total Compensation Charged to OM&A	10,235,768	13,404,592	15,529,349	18,522,513
Total Compensation Capitalized	4,657,791	5,805,994	4,709,002	3,221,383

2010 SCORECARD

Attached is Hydro One Brampton's 2010 Scorecard for reference.

2010 SCORE CARD

Strategic Objective		Performance Measures	Target
Financial	Increase Shareholder Value	Net Income after Tax ($M)	IFRS $14.2 GAAP $11.6
		Controllable Cost Index (OM&A $_{actual}$ / OM&A $_{budget}$)	≤ 100%
Customer Commitment	Meet Service Quality Commitments	Customer Service Index *(# of measures meeting targets)*	8 of 9 indicators met
		Reliability Indices *(# of measures meeting target SAIDI, SAIFI & MAIFI)*	3 of 3 indicators met
	Satisfying our customers	Customer satisfaction *(% satisfied)*	≥90%
Business Excellence	Achieve Operational Excellence	Work Program Achievement *(% of projects under the control of HOB completed within budget)*	≥90%
		2011 Rate Application	By June 30th
		Convert financial systems to IFRS by year-end	100%
Organizational Strength	Achieve Health & Safety Excellence	Employee Safety *(Lost-time injuries)*	0
		Employee Safety *(Medical aids – WSIB accepted)*	≤ 6
	Achieve Environmental Excellence	Connect FIT and MICROFIT applications as per OPA requirements[4] *(100% of applications processed within OPA requirements)*	100%
		Meet OPA CDM targets	3 of 4
		Prepare plan to green the fleet *(Plan prepared by April 30th)*	By April 30th
		Smart meters enabled to support time-of-use billing *(90% of smart meters with reliable network)*	≥90%

Attached is Hydro One Brampton's 2010 Scorecard for reference.

2011 SCORE CARD

Strategic Objective		Performance Measure	Target
Financial	Increase Shareholder Value[1]	Net Income after Tax ($M) *(Forecast)*	IFRS $13.6 GAAP $9.2
		Controllable Cost Index *(OM&A actual / OM&A budget)*	≤ 100%
Customer Commitment	Meet Service Quality Commitments	Customer Service Indices *(% of measures meeting target*)	8 of 9 indicators met
		Reliability Indices *(# of measures meeting target SAIDI, SAIFI & MAIFI)*	3 of 3 indicators met
	Satisfying our customers	Customer satisfaction *(% satisfied)*	≥90%
Business Excellence	Achieve Operational Excellence[1]	Work Program Achievement *(% of projects under the control of HOB completed within budget)*	≥90%
Organizational Strength	Achieve Health & Safety Excellence	Employee Safety *(Lost-time injuries)*	0
		Employee safety *(Medical aids – WSIB accepted)*	6
	Achieve Environmental Excellence	Connect FIT and MICROFIT applications as per OPA requirements	(100% of applications processed within OPA requirements)
		Meet OPA CDM targets (if any)	100%

[1] *A variance from plan of + or – 5% is considered on plan*

EXHIBIT 4 TAB 5

SHARED SERVICES / CORPORATE COST ALLOCATION

SHARED SERVICES / CORPORATE COST ALLOCATION

Hydro One Brampton Networks Inc. is a wholly owned subsidiary of Hydro One Inc. (HOI) and an affiliate of Hydro One Networks Inc. (HONI). By agreement, HOI and HONI provide certain Common Corporate Functions and Services (CCFS) to HOBNI for an annual fee.

CCFS services include corporate management, finance, human resources, corporate communications and services, legal, regulatory affairs, corporate security, and internal audit.

HOI and HONI have identified certain functions that provide common services to all business units. It was determined that these functions could be shared effectively by all business units, avoiding costly and unnecessary duplication. Shared services cost levels are fully reviewed as part of the annual business planning process.

Table 1, below, presents for comparison purposes the total CCFS costs over the Historic, Bridge and Test years as well as the 2010 and 2011 allocation amounts.

Table 1: Common Corporate Functions and Services

($ Thousands)						
Description	**Historic**				**Bridge**	**Test**
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Corporate Management	59	88	64	61	65	67
Finance	506	285	274	297	499	446
General Counsel and Secretariat	151	156	169	184	199	204
Total CCF&S Costs	716	529	507	542	763	717

Table 2 presents the fees paid to Hydro One Inc. (HOI) for Corporate Services.

Table 2: Fees paid to HOI for Services

Fees paid to HOI for Services ($ Thousands)						
Description	**Historic**				**Bridge**	**Test**
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Corporate Management	41	43	36	34	33	34
Finance	49	45	38	41	38	39
General Counsel and Secretariat (i	20	20	19	20	19	20
Total CCF&S Costs	110	108	93	95	90	93

Table 3 presents the fees paid to Hydro One Networks Inc. (HONI) for Corporate Services.

Table 3: Fees paid to HONI for Services

Fees paid to HONI for Services ($ Thousands)						
Description	**Historic**				**Bridge**	**Test**
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Corporate Management	18	45	28	27	32	33
Finance	457	240	236	256	461	407
General Counsel and Secretariat	131	136	150	164	180	184
Total CCF&S Costs	606	421	414	447	673	624

CORPORATE MANAGEMENT

Corporate Management represents functions responsible for providing overall strategic direction to the corporation, including the Board of Directors, Chief Executive Officer ("CEO"), the General Counsel and Secretary as well as the costs of certain supporting functions, such as Executive Office support and External Relations.

The President, CFO, General Counsel and Secretary are considered to be part of Hydro One Inc. and provide services to Hydro One Brampton Networks Inc.

The function of the General Counsel and Secretary is to provide advice and support to the Board of Directors and Corporate Officers. They provide advice and training, report on Code of Conduct, report on activities related to the *Freedom of Information and Privacy Act* as well as the *Federal Personal Information Protection and Electronic Documents Acts*.

The CFO is responsible for the oversight of the Finance function and the reporting of information to Hydro One Inc. subsidiaries, regulators, investors and the shareholder. This includes the review and approval of financial and investment decisions, business and strategic plans and ensuring integrity of, and compliance with, internal controls over regulatory, financial and accounting activities.

FINANCE

Overview

Finance provides strategic advice and services related to the planning, processing, recording, reporting and monitoring of all financial transactions taking place within the organization.

Services are provided through the following specialist functions:

- Corporate Controllers
- Corporate Tax
- Treasury

Corporate Controllers

Corporate Controllers provides leadership and direction regarding all business planning, financial reporting, accounting and internal control policies and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles. This includes leading the IFRS conversion project.

The function oversees the development of actual and forecast financial information and manages reporting processes to appropriate audiences or stakeholders. Corporate Controllers are responsible for establishing and leading the annual business planning and budgeting processes and presentation of the plan to the Board of Directors and the Provincial Government. This function is also responsible for managing and providing direction to the company with respect to matters of internal control, including Organization Authority Registers, financial policies and procedures and providing leadership regarding compliance with Bill 198 and associated Ontario Securities Commission related rules.

Corporate Tax

Corporate Tax manages the tax obligations of each corporation within the Hydro One Inc. group including corporate income and capital taxes, the federal goods and services tax, the provincial

retail sales tax, debt retirement charge, payroll and non-resident withholding tax and the employer health tax. Corporate Tax ensures that internal and external tax compliance requirements are met.

Corporate Tax costs have remained constant over the 2006 - 2011 period.

Treasury

Treasury total costs are related to the following:

- Execute borrowing plans and issue commercial paper and long-term debt.
- Ensure compliance with securities regulations, bank and debt covenants.
- Manage the company's daily liquidity position, control cash and manage the company's bank accounts.
- Settle all transactions and manage the relationship with creditors.
- Communicate with debt investors, banks and credit rating agencies.
- Costs incurred in relation to assessment of risk, negotiation and purchase of insurance policies, claims management and settlement. These costs represent the premiums paid for third party liability, fiduciary liability, directors and officers insurance, and also the cost of self-insurance for liability exposures that are either not covered by insurance policies or fall below the specified deductibles.
- Costs representing Decision Support costs which were previously part of Financial Strategy. Decision Support provides services such as business case review, business valuation, transaction support, and other services as required. The function develops and maintains financial models.
- Provides analytical support for a variety of financial planning and reporting processes.

GENERAL COUNSEL AND SECRETARIAT

The offices of the General Counsel and Secretary (GC&S) provide legal advice and direction to Hydro One Inc. and its operating subsidiaries, as well as overall guidance in the areas of corporate structure, governance, business ethics and the business code of conduct. The GC&S function consists of two main functions: Law and the Corporate Secretariat. The Corporate Secretariat reports to the General Counsel. The GC&S functions in Hydro One Networks Inc. consist of:

- Provision of legal services to all business units including the Company's major borrowing and financing initiatives, regulatory activities, Transmission and Distribution businesses (contracts, other commercial matters), employment, including pension and benefits, health, safety and environment, litigation, all Board of Directors related activities, and arranging for the provision of legal services to the Corporation. The volume of these services is driven by capital and OM&A activities, as well as increasing regulatory and legislative oversight functions;
- Overseeing the Law and Corporate Secretariat functions;
- Ensuring compliance with legal and regulatory requirements.
- Hydro One does most of its legal work in-house, except when the in-house expertise is not available (for example, tax, labour) or when the workload exceeds the capacity of the internal legal group.

LAW

Law provides legal advice to all business units of the Corporation, acting as an internal "law firm" for the corporation. It advises on most aspects of law affecting the corporation, and relies on its experience and knowledge of the Company's business in providing economic and timely advice. The Law function maintains core knowledge of the law and the Company's business.

Corporate Secretariat

The Corporate Secretariat provides support to the Office of the Chair, the Board of Directors and its Committees, including the administrative aspects of the Board and its meetings. It provides advice and analysis with regard to a variety of board-related matters, including corporate governance best practices and emerging trends and issues. It provides advice and direction with regard to the business Code of Conduct, ensuring appropriate actions to resolve known or suspected violations. This group also has responsibility for Community Citizenship initiatives advising the Corporation on compliance with privacy legislation, and administering requests for information under the *Freedom of Information and Privacy Act*.

SHARED SERVICES WITH AFFILIATES

Shared Services with Affiliates have been described in Tab 5 Schedule 1.0 Shared Services / Corporate Cost Allocations (previous Schedule).

CORPORATE COST ALLOCATION METHODOLOGY

Hydro One Brampton does not have any shared services that are chargeable to any of its affiliates.

PRICING METHODOLOGY

Hydro One Brampton does not have any shared services that are chargeable to any of its affiliates.

SHARED SERVICE VARIANCE ANALYSIS

There are no shared services variances that exceed Hydro One Brampton's materiality threshold of $300,000.

EXHIBIT 4 TAB 6

PURCHASE OF NON-AFFILIATE SERVICES

PURCHASE OF GOODS AND SERVICES SUMMARY

As a component of Hydro One Brampton's OM&A expenses, various goods and services are purchased from non-affiliated vendors. Hydro One Brampton's procurement policies and sourcing strategies work to promote effective competition with regard to the nature of the products or services being acquired.

All purchases over $20K require a competitive bidding process. Purchases under that amount regularly require written quotations from at least three approved vendors. The policy outlines when this requirement may be waived such as in the case of a single source vendor, timing or technical issues that limit the number of quoting vendors.

Total services related to OM&A expenses were reviewed. The tables below provide information on vendor transactions with Hydro one Brampton in the years 2006 – 2009 for total services in excess of the materiality threshold of $300,000. Estimates of 2010 and 2011 transactions are also provided.

Hydro One Brampton's purchasing policy is provided as Schedule 1.2 of this Tab.

SERVICES PURCHASED BY SUPPLIER

Table 1: Services Purchased by Supplier (in thousands)

SERVICES PURCHASED BY SUPPLIER

Exhibit 4 Tab 6 - Table 1: Services Purchased by Supplier (in thousands)

(All amounts in thousands)

Vendor	Product / Service	Selection Method	2006	2007	2008	2009	2010	2011
A&W High Voltage	Labour	Competitive Bid	1,572	2,081	1,776	1,686	2,266	1,800
ABB Inc.	Transformers	Competitive Bid	1,422	1,378	1,188	1,146	810	1,200
Able-One Systems Inc.	IT Services	Competitive Bid	25	77	158	61	40	40
Avertex Utility Solutions	Labour	Competitive Bid	850	29	-	-	-	-
Bethlehem Trenching	Labour	Competitive Bid	1,674	2,023	1,366	1,206	1,000	1,000
Bel Volts Sales Ltd.	Inventory	Competitive Bid	244	317	214	219	59	160
Bell Canada	Phone Services	Sole Source	190	211	192	175	55	170
Bothwell-Accurate Co. Ltd.	Roof Repairs	Competitive Bid	1,086	-	86	196	-	-
Cable Control Systems Inc.	Locates	Competitive Bid	311	307	316	292	310	300
Canada Post Corp.	Postage	Sole Source	626	701	726	784	780	780
Canada Power Products	Inventory	Sole Source	28	406	-	-	-	-
Canadian Tech Air	HVAC Retrofit	Competitive Bid	-	420	905	44	156	-
City of Brampton	Property Tax & Labour	Sole Source	869	563	572	627	501	512
Composite Power Group	Inventory	Competitive Bid	210	188	310	424	216	250
D.L. Hannon	Labour	Competitive Bid	-	615	34	-	-	-
Enviro-Energy Technologie	Photo-Voltaic System	Competitive Bid	-	312	7	-	-	-
General Cable	Wire & Cable	Competitive Bid	199	90	887	327	252	260
Guelph Utility Pole	Wood Poles	Sole Source	239	392	288	722	200	300
HD Supply Canada	Inventory	Competitive Bid	1,619	1,306	1,185	1,973	1,300	1,600
Intergraph Canada Ltd.	OMS system	Sole Source	262	425	116	201	197	200
Itron Canada Inc.	Software Support	Sole Source	345	179	91	104	86	90
Jaco Environmental	Oil Testing	Competitive Bid	-	-	63	401	188	-
Joe Johnson Equipment Inc.	Vaccum Excavation Truck	Sole Source	-	-	365	29	10	30
Kinectrics Inc.	Consulting	Competitive Bid	-	-	-	318	151	-
Manulife Financial	Health & Dental Benefits	Sole Source	1,012	1,126	918	1,010	1,150	1,200
Mattamy (Credit Valley)	Labour	Sole Source	-	-	-	398	-	-
Mearie Management Inc.	Long Term Disability & Life Ins.	Sole Source	118	133	364	386	400	400
Nexans Canada	Inventory	Competitive Bid	1,291	308	360	392	225	289
Olameter Inc.	Meter Reading	Competitive Bid	772	813	883	710	248	-
Ontario Excavac Inc.	Labour	Competitive Bid	275	223	180	318	480	350
Posi-Plus Ontario Inc.	Vehicles	Competitive Bid	40	473	282	603	2,055	2,147
Prysmian Power Cables	Inventory	Competitive Bid	945	896	63	522	1,000	448
R.B. Somerville Co.	Labour	Competitive Bid	186	-	-	1,640	-	-
Rodan Energy & Metering	Labour & Equipment	Competitive Bid	559	154	147	75	181	150
S&C Electric Canada	Inventory	Sole Source	328	358	168	331	414	482
Sandringham Place Inc.	Feeder Costs	Sole Source	334	-	218	-	-	-
Soil-Vac Inc.	Labour	Competitive Bid	492	541	752	388	374	380
StressCrete Ltd.	Inventory	Competitive Bid	572	573	519	601	631	660
Survalent Technology	SCADA Upgrade & Inventory	Sole Source	91	58	54	18	34	-
Trilliant Energy Services	Smart Meter Supply/Install	Competitive Bid	-	300	292	379	-	-
Trilliant Networks	Inventory	Competitive Bid	17	4,520	4,609	5,945	5,742	6,200
Westburne Ruddy Ontario	Inventory	Competitive Bid	340	252	220	151	71	89

PURCHASING POLICY

SUPPLY CHAIN MANAGEMENT

Hydro One Brampton's Procurement Group (Purchasing and Stores) is responsible for the acquisition of goods and services for the Company. This Group is accountable for the start to end process of acquiring, receiving, storing and issuing all goods and services. The focus is on the right product with the right quality, at the right place, right time and at the right cost.

The proposed 2010 costs for Purchasing and Stores, excluding depreciation, are expected to be $1,263 thousand, with a slight increase to $1,298 thousand in 2011. These services include strategic sourcing (purchase) of materials and services, storage and distribution of materials; transportation, inventory management, and investment recovery of disposed assets. Purchasing and Stores costs are allocated to work programs and projects through the material surcharge rate.

The increasing overall cost levels represent enhanced service levels to meet business needs in the areas of contract management, inventory management and sourcing. The increase in supply chain costs in the period 2007 to 2009 primarily reflects the addition of a buyer during 2008 required as support for the growth in the Capital and OM&A work programs across the organization. The increase over the 2009 to 2011 period primarily reflects changes to burden rates for both labour and vehicles arising from a comprehensive review completed in 2009.

Table 1: Table Supply Chain ($ Thousands)

	Historic			Bridge	Test
	2007	**2008**	**2009**	**2010**	**2011**
Total *	969	1,029	1,142	1,263	1,298

** Excluding depreciation*

Supply Chain Policies and Procedures

The Company's Procurement Policy stipulates that all acquisitions will be covered by a purchase order (with some limited exceptions, such as utilities and taxes). Spending authority is defined in the Policy, and controlled by electronic workflow. Acquisitions for most requirements are done either by formal tender, RFP, or written quotations. Hydro One Brampton operates a fair and transparent procurement process that gives all companies equal opportunity to do

business consistent with its Procurement Policy. Tenders and proposals are evaluated based on predefined evaluation criteria by cross functional teams. The outcome of the evaluation is the foundation for awarding procurement contracts.

Sourcing of Materials and Services

- The sourcing of materials and services includes the following:
- Demand Management and Procurement – Market intelligence with respect to commodities, processing purchase transactions and inspecting and expediting services to ensure delivery to contract commitments.
- Sourcing and Vendor Management – Services to support sourcing all commodities and services which include managing the size and composition of the vendor base, resolving issues, managing inventory levels and negotiating stocking arrangements.

Hydro One Brampton manages its procurement and supply base by using strategic sourcing in the acquisition of goods and services. Strategic sourcing is a disciplined business process for purchasing goods and services on a Company-wide basis using cross-functional teams to manage the supply base as a valued resource. The methodology's five-step process includes spending analysis, market analysis, development of a sourcing strategy, negotiation and award and contract management.

Material and Inventory Management

Hydro One Brampton has two active committees providing advice and support to the procurement process. The Material Committee is engaged in providing evaluation services to assure that products are manufactured in accordance to specifications established by Hydro One Brampton. The Inventory Committee conducts analysis of specific asset groups and makes recommendations regarding appropriate levels of on hand critical parts as well as guidance to field staff on the appropriate replacement part when a failure occurs. The work of both of these committees provides an important control ensuring inventory levels are maintained at an appropriate level.

Storage and Distribution of Materials – Warehousing

Hydro One Brampton's warehouse operation is attached to the administrative building complex. This operation provides the storage and distribution of materials for the field staff. Four stock keepers are assigned to the warehouse and are responsible for receiving shipments and for

storing material, cycle counting, shipping and tracking inventory. Deliveries to the warehouse are provided directly by parts suppliers. The Purchasing Expediter manages and coordinates the delivery of materials on the scheduled delivery date to the warehouse or directly to the work site to ensure that the field operation receives the right material at the right time.

Investment Recovery

The final step of the supply chain is the responsible disposal and investment recovery of end-of-life assets. During the period from 2005 to 2009 the recovery ranged from $74 thousand to $197 thousand, and primarily involved sales of scrap metal. Hydro One Brampton continues to focus on extracting the maximum value possible from the sale of these assets. A breakdown of the sale of scrap by year is as follows:

Table 2: Breakdown of Sales of Scrap Metal through Investment Recovery Program ($000)

	2005	2006	2007	2008	2009
Scrap Metal Recovery	74	128	197	174	127

Cost Savings from Strategic Sourcing

Strategic sourcing results vary from commodity to commodity or from one service to another. The main benefits of sourcing strategies are described below:

- Active involvement of internal stakeholders to communicate their business needs for the products and services;
- Cost reduction by increased leverage of Company-wide expenditures – purchases are consolidated by commodity and/or service to ensure that the business receives maximum value. This eliminates the need to tender and purchase as requirements surface -- an added benefit of this approach;
- Reduced total life cycle cost for materials and services – when purchasing equipment, all aspects are identified to ensure that Hydro One Brampton acquires maximum value for the life cycle of the equipment. For example, specifications, maintenance requirements, installation services and warranty services are defined and reviewed to ensure that business needs will be met, and order and invoice processes, lead time and inventory

requirements, etc. are evaluated to determine where greater efficiencies may be realized;

- Improved security of supply through longer-term agreements. To maximize value, longer-term agreements are established with fixed prices, or formula pricing is considered to ensure that Hydro One Brampton achieves best value;
- Improved and/or consistent quality of material and services.

Strategic sourcing will continue to be a major focus, as the Company emphasizes cost control and security of supply during a volatile commodity market, while demand in the global utility sector increases.

Productivity Improvements in Supply Chain Management

Hydro One Brampton is interested in continuous improvement, and supply chain management is one example. This section details some work in progress to provide effectiveness and efficiency gains.

Overall, the continued goal is to minimize the investment in inventory, and improve service levels. Continuous improvement is at the forefront to ensure the inventory is relative to the Company's needs. A major initiative going forward is to position Procurement to play a more supportive and leadership role in the acquisition of non-stock goods and services. Significant inroads have already been established where the Procurement Group provides the needed guidance with respect to the best sourcing and tendering methodologies.

The supply management process is evolving, however, to consider the broader work program over multiple years, and obtain quotes for materials required over multiple delivery dates. This approach assists vendors by allowing them to better plan their activities, and leads to lower costs and a stronger relationship between Hydro One Brampton and the vendor – which has additional benefits if difficulties arise in the supply of materials. Hydro One Brampton has also developed "blanket purchasing orders" with vendors to establish a standing order or relationship for critical materials, such as poles, cable and transformers.

Hydro One Brampton currently has long-standing alliances with three key suppliers for pad mounted transformers, pole and vault type transformers, and wood poles. Regular scheduling meetings between all involved internal departments enable us to set up direct to site 'just in time' deliveries with these suppliers to help keep the carrying costs to a minimum.

Hydro One Brampton establishes numerous blanket purchase orders to hold an agreed to price for at least a year on many repetitive stock items. Baseline prices are established through a competitive bid process, and because of this pre-agreed pricing, buyers do not have to go through a pricing and availability cycle every time these items appear on the re-order point report. This approach minimizes the time spent on low dollar activity, and allows buyers to focus on more strategic vendor communications. While the Company does not guarantee forecasted quantities for the year, the historical information usage available provides a fair indication of requirements allowing for quantity discounts, and reduced lead times on deliveries.

Streamlining standards is another way in which Hydro One Brampton is improving the strategic sourcing process. In addition to simplifying procurement, this also increases both the likelihood that spares will be available for use, and the ease of maintaining a lower inventory.

EXHIBIT 4 TAB 7

DEPRECIATION / AMORTIZATION

DEPRECIATION REVIEW

In January 2006, the Canadian Accounting Standards Board (AcSB) announced its decision to replace Canadian GAAP with International Financial Reporting Standards (IFRS) for all publicly accountable enterprises. On July 28 2009, the Ontario Energy Board issued report EB-2008-0408, *Transition to International Financial Reporting Standards*, whereby it set forth regulatory policy regarding the transition to IFRS. The Board concluded that "…*the basis of the current regulatory accounting system, CGAAP, will be replaced by IFRS, and will no longer be available for financial or regulatory accounting. The current system is CGAAP, including modifications for regulatory purposes. The new system at January 1, 2011, will be IFRS, with modifications for regulatory purposes.*"

Hydro One Brampton request that the OEB approve its updated asset lives as submitted in Table 1 below, per lives indicated under "revised useful life IAS 16", and per Table 2 below, revised depreciation rate.

The transition to IFRS for both financial and regulatory reporting will require changes to various depreciation accounting practices previously approved by the Board and accordingly permitted by CGAAP. The new accounting standard governing depreciation accounting is International Accounting Standard 16 Property, Plant and Equipment (IAS16).

Depreciation service lives being used by HOBNI were initially prescribed by the former Ontario Hydro for utilities that were subject to reporting under the Accounting for Municipal Electric Utilities in Ontario manual (MUManual). On January 1, 2001 the guidance for depreciation practices provided in the MUManual was superseded by the Accounting Procedures Handbook for Electric Distribution Utilities (APH). The APH prescribes a Uniform System of Accounts with cross-reference in Appendix E to the plant accounts, service lives and deprecation rates previously prescribed in the MUManual. Article 410 of the APH directs municipal utilities to *"…use these rates until a change can be supported by an objective study and the change has been authorized by the Board."* Accordingly, HOBNI continued to use the MUManual service lives and depreciation rates in compliance with the APH. On July 28, 2009, the Board issued report EB-2008-0408, Transition to International Financial Reporting Standards, where it stated "*Because IFRS does not currently recognize industry-specific accounting applicable to regulated enterprises, utilities in Ontario that have relied upon the Board to establish certain aspects of*

depreciation accounting will now be required to apply the accounting requirements of IFRS for financial reporting". Furthermore the Board goes on to state that "*Any electrical utility retains the option of demonstrating, through a well-founded depreciation study, that the Board should approve specific deprecation methodologies and rates for that utility".*

As part of its transition to IFRS, Hydro One Brampton conducted a review to ensure that the accounting treatment of the Company's property, plant and equipment and intangible assets was in accordance with IAS 16. This review was carried out in consultation with the Company's external IFRS advisors and with Foster Associates Inc. The Foster Associates Inc. portion of the review focused on depreciation service lives for assets installed after January 1, 2010 and this review was led by Dr. Ron White. The review commenced in December 2009 and progressed through mid-April 2010.

Among the IAS 16 changes affecting Hydro One Brampton is the requirement to disaggregate property, plant and equipment previously classified in uniform systems of accounts in conformance with Article 220 of the APH's USoA into "items of property" and depreciate each item and significant parts of an item separately. IAS16 also requires cessation of group depreciation methods and prescribes an item accounting procedure instead. IAS 16 also necessitates recognition of a gain or loss upon asset de-recognition (i.e. retirement or sale) of any item of property, plant and equipment (PPE).

The depreciation review conducted with Foster Associates Inc. was based on individual plant accounts (Profile IDs) disaggregated from UsoA's. Foster Associates Inc. reviewed and concurred with each of the proposed asset service life estimates. **Table 1** below identifies current USoA plant accounts and newly defined asset categories for implementation of IAS16 depreciation accounting rules. The table also contains a summary of current USoA service lives and service lives estimated for the newly defined asset categories.

The componentization framework described above could not be applied to legacy PP&E investments deemed acquired for external reporting purposes at net book value on January 1, 2010. Net book value was determined by deducting accumulated amortization, and capital contributions, where applicable, to the capital additions for each USoA plant account. The Company determined that there were significant information availability constraints that limited its options in componentizing legacy assets on a basis that is consistent with the go-forward account structure of Profile ID's.

HOBNI has decided to continue to depreciate its legacy assets by USoA. The depreciation rate to be applied to each USoA has been determined by applying an appropriate IFRS-compliant depreciation rate. In accordance with the componentization strategy previously discussed for legacy assets, HOBNI undertook a systematic approach of deriving a new useful life for each USoA taking into account all available information. **Table 2** below shows the useful lives for legacy assets by USoA.

Table 1: USoA Accounts

USoA account number	USoA account description	USoA sub-account number	IFRS Asset Categories (Components)	Component Description	OEB prescribed useful life	Revised useful life per IAS 16
1610	Miscellaneous Intangible Plant	1610	1610001	Intangible Assets - Computer Software	5	5
		1610	1610002	Intangible Assets - T.S. Contributions	40	40
1805	Land	1805	1805001	Land	Not depr.	Not depr.
1806	Land Rights	1806	1806001	Land rights - Indeterminate	Not depr.	Not depr.
		1806	1806002	Land rights - Finite	Variable	Variable
1808	Buildings & Fixtures	1807	1808002	Buildings - Brick	50	50
		1809	1808001	Sandalwood Building	50	50
1815	Trans Station Equipment	1815	1815001	TS Transformers & Tap Changers	40	40
		1815	1815002	TS Primary HV Switches	40	30
		1815	1815003	TS Protection/Auto transfer sys & ancillary equipment	40	20
		1815	1815004	Bus Work & Cubicles	40	40
		1815	1815005	TS Breakers & Reclosures & Local Control Sys	40	40
		1815	1518006	TS Battery Systems & Chargers / Inverters	40	10
		1815	1815007	TS Station Service Equipment	40	40
		1815	1815008	TS Cables & Terminations	40	30
		1815	1815009	TS Instrument Transformers (It's)	40	40
		1815	1815010	TS Station Meters	40	10
		1815	1815012	TS Ancillary Metering Equipment	40	10
1820	Dist Station Equipment	1820	1820001	MS Transformers & Tap Changers	30	40
		1820	1820002	MS Primary HV Switches	30	30
		1820	1820003	MS Protection/Auto Transfer Sys & Ancillary Equip	30	20
		1820	1820004	MS Bus Work & Cubicles	30	40
		1820	1820005	MS Breakers & Reclosures & Local Control Syst.	30	40
		1820	1820006	MS Battery Systems & Charges / Inverters	30	10
		1820	1820007	MS Station Service Equipment	30	40
		1820	1820008	MS Cables & Terminations	30	30
		1820	1820009	MS Instrument Transformers (It's)	30	40
		1820	1820010	MS Station Meters	25	15
1830	Poles, Towers & Fixtures	1830	1830001	Poles - Wood	25	40
		1830	1830002	Poles - Non Wood	25	50
1835	OH Conductors & Devices	1835	1835001	O/H Prim Main Ln Conductors Inc. Neutral & Ln Arrest	25	50
		1835	1835002	Secondary Main Line Conductors	25	50
		1835	18350004	Switches	25	25
1840	Underground Conduit	1840	1840001	Underground Conduit - Direct Buried	25	50
		1840	1840002	Underground Conduits - Concrete Encased	25	75
1845	U/G Conductors and Devices	1845	1845001	Primary Cables	25	30
		1845	1845004	Switches and Switchgear	25	30
		1845	1845010	Underground Secondary Cables	25	50
1850	Line Transformers	1850	1850001	Overhead Transformers	25	40
		1850	1850002	Underground Transformers	25	40
1855	Services	1855	1855001	All Low Voltage (120 - 600V) O/H Services	25	50
		1855	1855002	U/G/ Low Voltage (120 - 600V) Services	25	50
1860	Meters	1860	1860001	Non-IT based Meters	15	15
		1860	1860002	IT based Meters	15	15

1908	Buildings & Fixtures	1908	1908001	Solar Panels	25	25
1915	Office Furniture & Equipment	1915	1915001	Office Furniture and Equipment	10	10
1920	Computer Equipment - Hardware	1920	1920001	Servers, Desktops, Sans	5	5
1930	Transportation Equipment	1930	1930001	Automobiles	4	7
		1930	1930002	Trucks Under 3 Tonnes	5	10
		1930	1930003	Trucks Over 3 Tonnes / Trailers	8	10
1935	Stores Equipment	1935	1935001	Stores Equipment	10	10
1940	Tools, Shop and Garage Equip	1940	1940001	Tools, Shop and Garage Equip.	10	10
1950	Power Operated Equipment	1950	1950001	Power Operated Equipment	8	8
1955	Communication Equipment	1955	1955001	Communication Equipment	10	10
1960	Miscellaneous Equipment	1960	1960001	Miscellaneous Equipment	10	10
1980	Supervisory Control Equipment	1980	1980001	Remote Switch SCADA Battery	15	7
		1980	1980002	Remote Switch SCADA Motor Operator	15	15
		1980	1980003	Remote Switch SCADA Enclosures and Equipment	15	15

Table 2: Useful Lives for Legacy Assets

US of A	Original Dep'n Rate	Revised dep'n rate for legacy assets
1805	Not depreciated	Not depreciated
1806	50	50
1808	50	50
1815	40	40
1820	30	40
1830	25	42
1835	25	50
1840	25	50
1845	25	35
1850	25	40
1855	25	50
1860	15	15
1915	10	10
1925	5	5
1930	4	7
1930	5	10
1930	8	10
1935	10	10
1940	10	10
1950	8	8
1955	10	10
1960	10	10
1980	15	7

DEPRECIATION / AMORTIZATION EXPENSE

Depreciation and Amortization on capital assets consisting of PP&E and intangibles, was calculated as shown in the following tables:

DEPRECIATION EXPENSE BREAKDOWN

Table 1: Depreciation Expense – 2006

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,191,402	44,510	8,146,892	(44,510)	8,124,637	-	-
1806	Land Rights	1,304,586	113	1,304,473	58,458	1,333,702	50	26,674
1808	Buildings and Fixtures	25,172,436	23,353	25,149,083	1,099,999	25,699,083	various	543,636
1815	Transformer Station Equipment - Normally Primary above 50 kV	10,677,293	-	10,677,293	3,474	10,679,030	40	266,976
1820	Distribution Station Equipment - Normally Primary below 50 kV	40,190,523	5,276,442	34,914,080	639,781	35,233,971	various	1,554,686
1830	Poles, Towers and Fixtures	38,001,773	1,189,491	36,812,282	5,802,455	39,713,509	25	1,588,540
1835	Overhead Conductors and Devices	10,913,710	-	10,913,710	2,191,510	12,009,465	25	480,379
1840	Underground Conduit	6,742,620	-	6,742,620	2,284,568	7,884,904	25	315,396
1845	Underground Conductors and Devices	161,359,875	7,138,518	154,221,357	6,352,682	157,397,698	25	6,295,908
1850	Line Transformers	71,608,663	8,479,803	63,128,860	3,160,025	64,708,872	25	2,588,355
1855	Services	20,348,023	861,259	19,486,764	714,723	19,844,126	25	793,765
1860	Meters	20,038,385	1,335,304	18,703,081	1,170,387	19,288,275	25	771,531
1908	Buildings and Fixtures	-	-	-	-	-	25	-
1915	Office Furniture and Equipment	1,481,448	776,927	704,520	47,337	728,189	10	72,819
1920	Computer Equipment - Hardware	2,842,267	684,713	2,157,553	453,294	2,384,200	5	476,840
1925	Computer Software	194,587	-	194,587	226,383	307,778	5	61,556
1930	Transportation Equipment	7,020,102	326,260	6,693,843	388,348	6,888,016	various	604,317
1935	Stores Equipment	200,520	-	200,520	19,150	210,095	8	26,262
1940	Tools, Shop and Garage Equipment	2,091,557	746,610	1,344,947	152,979	1,421,436	10	142,144
1950	Power Operated Equipment	37,250	-	37,250	-	37,250	8	4,656
1955	Communication Equipment	244,108	-	244,108	50,146	269,181	10	26,918
1960	Miscellaneous Equipment	116,609	-	116,609	16,025	124,622	10	12,462
1980	System Supervisory Equipment	3,858,927	1,036,852	2,822,075	195,795	2,919,973	15	194,665
1995	Contributions and Grants - Credit	(48,500,552)	-	(48,500,552)	(4,471,257)	(50,736,181)	25	(2,029,447)
2055	Construction Work in Progress--Electric	-		-	682,425	341,213	none	-
2040	Electric Plant Held for Future Use	-		-	-	-	none	-
1610	Miscellaneous Intangible Plant	-		-	-	-	various	-
	TOTAL	384,136,113	27,920,155	356,215,957	21,194,176	366,813,045		14,819,037

Table 2: Depreciation Expense – 2007

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,146,892		8,146,892	-	8,146,892	-	-
1806	Land Rights	1,363,044	113	1,362,930	19,170	1,372,516	50	27,450
1808	Buildings and Fixtures	26,272,435		26,272,435	1,630,659	27,087,764	various	585,705
1815	Transformer Station Equipment - Normally Primary above 50 kV	10,680,767	-	10,680,767	12,600	10,687,067	40	267,177
1820	Distribution Station Equipment - Normally Primary below 50 kV	40,830,304	5,080,768	35,749,536	192,033	35,845,552	various	1,593,650
1830	Poles, Towers and Fixtures	43,804,228	1,907,592	41,896,637	5,777,486	44,785,380	25	1,791,415
1835	Overhead Conductors and Devices	13,105,220	-	13,105,220	1,983,311	14,096,876	25	563,875
1840	Underground Conduit	9,027,188	-	9,027,188	2,102,665	10,078,521	25	403,141
1845	Underground Conductors and Devices	167,712,557	8,208,901	159,503,656	23,445,365	171,226,338	25	6,849,054
1850	Line Transformers	74,768,688	8,561,110	66,207,577	2,278,674	67,346,914	25	2,693,877
1855	Services	21,062,746	861,259	20,201,487	793,538	20,598,256	25	823,930
1860	Meters	21,208,772	2,765,539	18,443,233	6,157,185	21,521,825	various	993,342
1908	Buildings and Fixtures	-	-	-	-	-	25	-
1915	Office Furniture and Equipment	1,528,785	1,041,732	487,053	86,526	530,315	10	53,032
1920	Computer Equipment - Hardware	3,295,561	720,937	2,574,624	476,458	2,812,853	5	562,571
1925	Computer Software	420,970	-	420,970	508,907	675,423	5	135,085
1930	Transportation Equipment	7,408,450	3,021,143	4,387,307	1,007,384	4,890,999	various	510,443
1935	Stores Equipment	219,670	-	219,670	0	219,670	10	21,967
1940	Tools, Shop and Garage Equipment	2,244,536	803,367	1,441,169	287,536	1,584,937	10	158,494
1950	Power Operated Equipment	37,250	1,360	35,890	0	35,890	8	4,486
1955	Communication Equipment	294,254	0	294,254	102,028	345,268	10	34,527
1960	Miscellaneous Equipment	132,634	-	132,634	15,620	140,444	10	14,044
1980	System Supervisory Equipment	4,054,722	1,087,866	2,966,856	208,555	3,071,133	15	204,742
1995	Contributions and Grants - Credit	(52,971,809)	-	(52,971,809)	(18,528,211)	(62,235,914)	25	(2,489,437)
2055	Construction Work in Progress--Electric	682,425		682,425	1,964,208	1,664,529	none	-
2040	Electric Plant Held for Future Use	-		-	-	-	none	-
1610	Miscellaneous Intangible Plant	-		-	-	-	various	-
	TOTAL	405,330,289	34,061,688	371,268,601	30,521,699	386,529,450		15,802,569

Table 3: Depreciation Expense – 2008

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,146,892		8,146,892	-	8,146,892	-	-
1806	Land Rights	1,382,214	75,692	1,306,522	7,069	1,310,056	various	26,201
1808	Buildings and Fixtures	27,903,094		27,903,094	1,283,556	28,544,872	various	631,907
1815	Transformer Station Equipment - Normally Primary above 50 kV	10,693,367	1,306,142	9,387,225	3,803,296	11,288,873	40	282,222
1820	Distribution Station Equipment - Normally Primary below 50 kV	41,022,337	5,308,751	35,713,586	(321,331)	35,552,920	various	1,414,344
1830	Poles, Towers and Fixtures	49,581,714	2,789,196	46,792,518	4,388,180	48,986,609	25	1,959,464
1835	Overhead Conductors and Devices	15,088,531	-	15,088,531	2,073,555	16,125,309	25	645,012
1840	Underground Conduit	11,129,854	-	11,129,854	1,926,785	12,093,246	25	483,730
1845	Underground Conductors and Devices	191,157,922	10,334,883	180,823,039	16,144,870	188,895,475	25	7,555,819
1850	Line Transformers	77,047,361	8,707,853	68,339,509	5,346,080	71,012,549	25	2,840,502
1855	Services	21,856,284	861,259	20,995,025	544,543	21,267,297	25	850,692
1860	Meters	27,365,957	3,477,948	23,888,009	6,392,693	27,084,355	various	1,280,788
1908	Buildings and Fixtures	-	-	-	-	-	25	-
1915	Office Furniture and Equipment	1,615,311	1,306,663	308,647	84,367	350,831	10	35,083
1920	Computer Equipment - Hardware	3,772,019	928,809	2,843,210	155,453	2,920,937	5	584,187
1925	Computer Software	929,876	320	929,556	184,032	1,021,572	5	204,314
1930	Transportation Equipment	8,415,834	3,192,456	5,223,378	51,794	5,249,275	various	472,752
1935	Stores Equipment	219,670	56,280	163,391	-	163,391	10	16,339
1940	Tools, Shop and Garage Equipment	2,532,072	1,093,477	1,438,595	156,761	1,516,975	10	151,698
1950	Power Operated Equipment	37,250	1,360	35,890	-	35,890	8	4,486
1955	Communication Equipment	396,282	-	396,282	78,757	435,661	10	43,566
1960	Miscellaneous Equipment	148,254	-	148,254	(3,116)	146,696	10	14,670
1980	System Supervisory Equipment	4,263,277	1,242,796	3,020,481	144,806	3,092,884	15	206,192
1995	Contributions and Grants - Credit	(71,500,020)	-	(71,500,020)	(16,082,800)	(79,541,420)	25	(3,181,657)
2055	Construction Work in Progress--Electric	2,646,633		2,646,633	(1,397,746)	1,947,760	none	-
2040	Electric Plant Held for Future Use	-		-	3,111,465	1,555,732	none	-
1610	Miscellaneous Intangible Plant	-		-	-	-	various	-
	TOTAL	435,851,987	40,683,887	395,168,101	28,073,070	409,204,636		16,522,311

Table 4: Depreciation Expense – 2009

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,146,892		8,146,892	-	8,146,892	-	-
1806	Land Rights	1,389,282	1,349,595	39,687	23,226	51,300	various	1,026
1808	Buildings and Fixtures	28,876,302		28,876,302	602,472	29,177,538	various	646,798
1815	Transformer Station Equipment - Normally Primary above 50 kV	14,929,647	3,187,395	11,742,252	257,953	11,871,228	40	296,781
1820	Distribution Station Equipment - Normally Primary below 50 kV	40,212,984	5,985,828	34,227,156	279,295	34,366,803	various	1,362,272
1830	Poles, Towers and Fixtures	53,969,895	3,695,410	50,274,484	7,128,905	53,838,937	25	2,153,557
1835	Overhead Conductors and Devices	17,162,086	-	17,162,086	2,214,142	18,269,157	25	730,766
1840	Underground Conduit	13,073,275	-	13,073,275	4,665,139	15,405,844	25	616,234
1845	Underground Conductors and Devices	207,302,793	11,405,253	195,897,539	7,731,744	199,763,411	25	7,990,536
1850	Line Transformers	82,393,441	8,768,441	73,625,000	6,198,764	76,724,382	25	3,068,975
1855	Services	22,400,827	861,265	21,539,563	613,536	21,846,330	25	873,853
1860	Meters	33,758,650	4,580,558	29,178,092	9,445,080	33,900,632	various	1,738,932
1908	Buildings and Fixtures	310,348	4,696	305,653	-	305,653	25	12,226
1915	Office Furniture and Equipment	1,699,677	1,323,547	376,130	2,570	377,415	10	37,741
1920	Computer Equipment - Hardware	3,927,472	2,310,005	1,617,467	70,653	1,652,794	5	330,559
1925	Computer Software	1,113,908	1,064,886	49,022	(32,681)	32,682	5	6,536
1930	Transportation Equipment	8,467,628	4,086,175	4,381,453	148,004	4,455,455	various	529,301
1935	Stores Equipment	219,670	56,280	163,391	-	163,391	10	16,339
1940	Tools, Shop and Garage Equipment	2,688,833	1,304,544	1,384,289	159,036	1,463,807	10	146,381
1950	Power Operated Equipment	37,250	1,360	35,890	-	35,890	8	4,486
1955	Communication Equipment	475,040	250	474,790	117,318	533,448	10	53,345
1960	Miscellaneous Equipment	145,138	12,713	132,425	8,554	136,702	10	13,670
1980	System Supervisory Equipment	4,446,485	1,368,588	3,077,898	64,979	3,110,387	15	207,359
1995	Contributions and Grants - Credit	(87,582,820)	-	(87,582,820)	(12,704,438)	(93,935,038)	25	(3,757,402)
2055	Construction Work in Progress--Electric	1,248,887	-	1,248,887	798,274	1,648,024	none	-
2040	Electric Plant Held for Future Use	3,111,465	-	3,111,465	258,332	3,240,631	none	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	5,118,257	2,559,128	none	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	84,843	42,421	none	-
1610	Miscellaneous Intangible Plant - TS in-service	3,175,683	-	3,175,683	(130,042)	3,110,661	various	77,767
1610	Miscellaneous Intangible Plant - Software in-service	1,879,555	-	1,879,555	61,000	1,792,706	5	358,541
	TOTAL	468,980,295	51,366,790	417,613,506	33,184,915	434,088,614		17,516,581

Table 5: Depreciation Expense – 2010

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,146,892		8,146,892	-	8,146,892	-	-
1806	Land Rights	1,191,543		1,191,543	336,248	1,527,792	various	7,085
1808	Buildings and Fixtures	18,568,062		18,568,062	480,643	19,048,705	various	670,136
1815	Transformer Station Equipment - Normally Primary above 50 kV	12,253,845		12,253,845	1,110,729	13,364,574	various	333,452
1820	Distribution Station Equipment - Normally Primary below 50 kV	12,559,518		12,559,518	1,064,281	13,623,799	various	603,123
1830	Poles, Towers and Fixtures	26,798,783	(18,700,986)	45,499,769	6,387,591	51,887,360	42	1,235,413
1835	Overhead Conductors and Devices	9,969,757	(6,835,707)	16,805,464	1,694,367	18,499,831	50	369,997
1840	Underground Conduit	10,808,202	(5,343,823)	16,152,025	2,944,732	19,096,757	50	381,935
1845	Underground Conductors and Devices	69,887,182	(108,825,698)	178,712,880	9,667,697	188,380,576	35	5,382,302
1850	Line Transformers	39,758,478	(16,545,680)	56,304,158	4,154,621	60,458,779	40	1,511,469
1855	Services	5,918,984	(8,245,042)	14,164,026	560,264	14,724,290	50	294,486
1860	Meters	28,158,172	2,861,431	25,296,741	477,000	25,535,241	15	1,702,349
1908	Buildings and Fixtures	276,496	(30,722)	307,218	-	307,218	25	12,289
1915	Office Furniture and Equipment	120,413	(246,766)	367,179	52,000	393,179	10	39,318
1920	Computer Equipment - Hardware	352,904	(554,984)	907,888	791,000	1,303,388	5	260,678
1925	Computer Software	-	-	-	-	-	5	-
1930	Transportation Equipment	3,394,612		3,394,612	1,904,000	5,298,612	various	704,519
1935	Stores Equipment	99,458	(63,933)	163,391	-	163,391	10	16,339
1940	Tools, Shop and Garage Equipment	848,639	(558,900)	1,407,539	324,000	1,569,539	10	156,954
1950	Power Operated Equipment	12,416	(23,474)	35,890	-	35,890	8	4,486
1955	Communication Equipment	421,175	(183,893)	605,068	40,000	625,068	10	62,507
1960	Miscellaneous Equipment	82,241	(58,741)	140,982	-	140,982	10	14,098
1980	System Supervisory Equipment	1,291,622	(3,366,575)	4,658,197	85,000	4,700,697	7	671,528
1995	Contributions and Grants - Credit	-	61,295,457	(61,295,457)	(9,847,187)	(71,142,644)	25	(2,845,706)
2055	Construction Work in Progress--Electric	798,274	-	798,274	31,066	829,340	None	-
2040	Electric Plant Held for Future Use	3,369,797	-	3,369,797	-	3,369,797	None	-
1610	Miscellaneous Intangible Plant - TS CIP	5,118,257	-	5,118,257	-	5,118,257	None	-
1610	Miscellaneous Intangible Plant - Software CIP	84,843	-	84,843	-	84,843	None	-
1610	Miscellaneous Intangible Plant - TS in-service	2,928,177	-	2,928,177	10,386,320	13,314,497	various	332,189
1610	Miscellaneous Intangible Plant - Software in-service	691,510	(247,384)	938,894	977,843	1,427,816	5	285,563
	TOTAL	263,910,252	(105,675,419)	369,585,671	33,622,215	401,834,464		12,206,510

Table 6: Depreciation Expense – 2011

Account	Description	Opening Balance (a)	Less Fully Depreciated (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + 0.5 x (d)	Years (f)	Depreciation Expense (g) = (e) / (f)
1805	Land	8,146,892		8,146,892	-	8,146,892	-	-
1806	Land Rights	1,494,492		1,494,492	168,685	1,663,177	various	10,791
1808	Buildings and Fixtures	21,358,223		21,358,223	920,192	22,278,415	various	683,834
1815	Transformer Station Equipment - Normally Primary above 50 kV	10,900,311		10,900,311	1,412,106	12,312,417	various	378,309
1820	Distribution Station Equipment - Normally Primary below 50 kV	13,518,399		13,518,399	765,648	14,284,047	various	623,725
1830	Poles, Towers and Fixtures	32,443,082	(19,879,715)	52,322,797	4,506,694	56,829,490	42	1,353,083
1835	Overhead Conductors and Devices	11,466,959	(7,175,941)	18,642,900	791,911	19,434,811	50	388,696
1840	Underground Conduit	13,410,271	(5,680,017)	19,090,288	3,002,693	22,092,980	50	441,860
1845	Underground Conductors and Devices	78,429,897	(110,302,267)	188,732,164	11,321,695	200,053,859	35	5,715,825
1850	Line Transformers	43,429,647	(17,158,189)	60,587,836	5,187,987	65,775,823	40	1,644,396
1855	Services	6,479,248	(8,245,042)	14,724,290	633,342	15,357,632	50	307,153
1860	Meters	28,635,172	3,263,164	25,372,008	847,000	25,795,508	15	1,719,701
1908	Buildings and Fixtures	276,496	(30,722)	307,218	-	307,218	25	12,289
1915	Office Furniture and Equipment	172,413	(241,166)	413,579	146,500	486,829	10	48,683
1920	Computer Equipment - Hardware	1,143,904	(122,106)	1,266,011	283,466	1,407,744	5	281,549
1925	Computer Software	-	-	-	-	-	5	-
1930	Transportation Equipment	5,298,612	-	5,298,612	2,207,000	6,402,112	various	917,569
1935	Stores Equipment	99,458	(63,933)	163,391	-	163,391	10	16,339
1940	Tools, Shop and Garage Equipment	1,172,639	(389,887)	1,562,526	75,000	1,600,026	10	160,003
1950	Power Operated Equipment	12,416	(23,474)	35,890	-	35,890	8	4,486
1955	Communication Equipment	461,175	(183,893)	645,068	131,000	710,568	10	71,057
1960	Miscellaneous Equipment	82,241	(58,741)	140,982	-	140,982	10	14,098
1980	System Supervisory Equipment	1,376,622	(286,506)	1,663,128	437,000	1,881,628	7	268,804
1995	Contributions and Grants - Credit	(9,847,187)	57,763,059	(67,610,246)	(12,363,428)	(79,973,674)	25	(3,198,947)
2055	Construction Work in Progress--Electric	4,014,340	-	4,014,340	(11,541)	4,002,799	None	-
2040	Electric Plant Held for Future Use	3,369,797	-	3,369,797	-	3,369,797	None	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	-	-	None	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	-	-	None	-
1610	Miscellaneous Intangible Plant - TS in-service	13,314,497	-	13,314,497	-	13,314,497	various	332,189
1610	Miscellaneous Intangible Plant - Software in-service	1,669,353	752,704	916,649	521,534	1,177,416	5	235,483
	TOTAL	292,329,368	(108,062,671)	400,392,039	20,984,484	419,052,272		12,430,973

DEPRECIATION / AMORTIZATION POLICY

Hydro One Brampton does not currently have a written Depreciation and Amortization policy. The Company follows the guidance provided in the OEB's Accounting Procedures Handbook. For IFRS accounting, the Company is in the process of codifying its accounting policies in consultation with its parent company. The Company's proposed accounting for PPE and intangible assets is in compliance with IAS 16 and IAS 38 Intangible Assets.

EXHIBIT 4 TAB 8

TAXES

(PILS, CAPITAL TAX AND PROPERTY TAXES)

SUMMARY OF TAXES

TAX CALCULATIONS

Hydro One Brampton is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Company does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the *Ontario Corporations Tax Act*. A copy of the 2009 Federal T2 and Ontario C23 tax return has been provided in Exhibit 4, Tab 8, Schedule 1.2. Income Tax amounts included in the 2010 and 2011 pro forma financial statements are based on estimates and will differ from the actual tax returns.

PILS FOR THE 2011 TEST YEAR

The 2011 Test Year's PILs have been calculated at $2,520,658. This PILs tax amount is significantly less than historical years due to reductions in tax rates and reductions in taxable income which was impacted largely by reductions to Depreciation Expense for accounting purposes due to the change in asset lives as determined in Hydro One Brampton's 2009/2010 depreciation study. These PILS calculations are part of the Revenue Requirement Model used by the Company and can be found in Exhibit 11 Tab 1 Schedule 8: Revenue Requirement Model. PILs are calculated by determining the taxable income T2S(1) for the 2011 Test Year and then calculating the amount based on the 2011 tax rates that were enacted on December 15, 2009.

Ontario Capital Taxes have been eliminated by the Canada Revenue Agency (CRA) effective July 1, 2010. The 2010 Bridge Year is the last year for the assessment of Ontario Capital Taxes. The details of the PILS tax calculations are summarized in Exhibit 4, Tab 8, Schedule 1.1.

PROPERTY TAXES

Hydro One Brampton owns numerous properties in the City Brampton. Property taxes are paid on a per property basis. For the 2011 Test Year, Hydro One Brampton estimated a 3.5% increase in property taxes, a conservative increase based on historical trends. Actual and estimated amounts for property taxes are shown in **Table 1**.

PILS TAX CALCULATIONS

Summary comparative PILS tax calculations for 2006 OEB Approved, 2010 Bridge Year, and 2011 Test Year can be found below in **Table 2**.

DETERMINATION OF 2011 TAXABLE INCOME

There are two major components for this calculation:

- Regulatory Accounting Income before Taxes, and
- Tax adjustments

Regulatory Accounting Income before Taxes

This is calculated based on the 2011 expected total revenues less the 2011 expected cost and expenses. The Regulatory Accounting Income before Taxes in 2011 is $15,816,388. The details of this calculation can be found in Exhibit 11 Tab 1 Schedule 8: Revenue Requirement Model.

Tax Adjustments

Tax adjustments are made for both temporary and permanent differences and reserves.

The temporary differences included are:

- The difference between depreciation for accounting purposes versus capital cost allowance (CCA) for tax purposes
- Non-deductible reserves
- The reserves included are:
  - The change in post employment benefits balance from 2010 to 2011, and
  - The change in Provision for environmental costs, and
  - Other provisions not deductible for tax purposes.
  - The change of Regulatory Liabilities balances has not been included in this calculation.

The permanent differences are for items deducted for accounting purposes and have been added back as they are not deductible for tax purposes:

- Meals & entertainment costs - $15,403
- Charitable Donations - $2,650
- Capital Items Expensed - $276,138

EXPECTED 2011 TAX RATES

HOBNI used a combined income tax rate of 28.25% for the 2011 Test Year. The Ontario Capital tax was eliminated on July 1, 2010. Ontario Capital tax rate for the 2011 Test Year is no longer a component of the Revenue Requirement. HOBNI has calculated PILs based on Federal and Provincial income tax rate reductions that were enacted on December 15th 2009.

Corporate Tax Rates used in the Revenue Requirement Calculations are based on the following table.

Table 1: Bridge and Test Year Tax Rates

Corporate Tax Rates for Tax Year	2010 Bridge Year	2011 Test Year
* OCT Exemption	- 441,353	-
Federal Income Tax	18.00%	16.50%
Ontario Income Tax	13.00%	11.75%
Combined Income Tax	31.00%	28.25%
Ontario Capital Tax Rate	0.075%	0.000%
Large Corporation Tax Exemption	-	-

** Based on the 2009 OCT exemption amount as $15M is allocated beween Hydro One Networks Inc. and Hydro One Brampton Networks Inc.*

The summary of income taxes for Hydro One Brampton 2006 Board Approved, 2010 bridge year and 2011 Test Year are shown in **Table 2** below:

Table 2: Summary of Income Taxes

Summary of Income Taxes			
Description	**2006 Board Approved**	**2010 Bridge**	**2011 Test**
Income Taxes	9,083,622	1,894,924	2,520,658
Large Corporation Tax	293,006		
Ontario Captial Tax	864,244	240,386	-
Total Taxes	**10,240,872**	**2,135,310**	**2,520,658**

Table 3 on the following page provides an outline of the details of Hydro One Brampton's calculation of PILs for 2010 and 2011.

Table 3: Comparative Tax Summary

Tax Calculations			
Description	**2006 Board Approved**	**2010 Bridge**	**2011 Test**
Determination of Taxable Income			
Utility Income Before Taxes	19,177,696	12,841,059	15,816,388
Book to Tax Adjustments			
Additions to Accounting Income:			
Amortization of tangible assets	12,792,510	10,863,414	10,924,907
Amortzation of intangible assets		617,752	567,672
Reserves from financial statements - balance at end of year	9,968,467	8,328,000	8,646,000
Realized Income from Deferred Credit Accounts			
Federal ITC's			
Other Additions	265,920	338,937	338,937
Total Additions	**23,026,897**	**20,148,103**	**20,477,516**
Deductions from Accounting Income:			
Captial cost allowance from Schedule 8	10,206,155	18,086,193	18,792,258
Cumulative eligble capital deduction from Schdeule 10	54,891	53,314	58,438
Reserves from financial statements - balance at beginning of year	6,039,507	8,544,474	8,328,000
Other Deductions	755,585	192,523	192,523
Total Deductions	**17,056,138**	**26,876,504**	**27,371,219**
Regulatory Taxable Income	**25,148,455**	**6,112,658**	**8,922,685**
Corporate Income Tax Rate	36.12%	31.00%	28.25%
Regulatory Income Tax	**9,083,622**	**1,894,924**	**2,520,658**
Calculation of Utility Income Taxes			
Income Taxes	9,083,622	1,894,924	2,520,658
Large Corporation Tax	293,006		
Ontario Capital Tax	864,244	240,386	-
Total Taxes	**10,240,872**	**2,135,310**	**2,520,658**
Tax Rates			
Federal Tax	22.12%	18.00%	16.50%
Provincial Tax	14.00%	13.00%	11.75%
Large Corporation Tax	**293,006**		
Calculation of Ontario Tax			
Total Rate Base	249,223,804	320,956,457	335,073,828
Less Exemption	- 244,929	- 441,353	-
Taxable Capital/Deemed Taxable Capital		**320,515,104**	**335,073,828**
OCT Rate		0.075%	0.000%
Ontario Captial Tax	**864,244**	**240,386**	**-**

Summary of Income Taxes			
Description	**2006 Board Approved**	**2010 Bridge**	**2011 Test**
Income Taxes	9,083,622	1,894,924	2,520,658
Large Corporation Tax	293,006		
Ontario Captial Tax	864,244	240,386	-
Total Taxes	**10,240,872**	**2,135,310**	**2,520,658**

PILS MODEL

Table 1: CCA Continuity Schedule 2010

CCA Continuity Schedule (2010)													
Class	**Class Description**	**UCC Prior Year Ending Balance**	**Less: Non-Distribution Portion**	**Less: Disallowed FMV**	**UCC Bridge Year Opening Balance**	**Additions**	**Proceeds of Dispositions**	**UCC Before 1/2 Yr Adjustment**	**1/2 Year Rule {1/2 Additions Less Disposals}**	**Reduced UCC**	**Rate %**	**CCA**	**UCC Ending Balance**
1	**Distribution System - 1988 to 22-Feb-2005**	143,257,210.00			143,257,210.00	480,642.85		143,737,852.85	240,321.42	143,497,531.42	4%	5,739,901.26	137,997,951.59
2	**Distribution System - pre 1988**	26,667,632.00			26,667,632.00			26,667,632.00	0.00	26,667,632.00	6%	1,600,057.92	25,067,574.08
3	**Buildings acquired before 1988**	2,069,821.00			2,069,821.00			2,069,821.00	0.00	2,069,821.00	5%	103,491.05	1,966,329.95
6	**Buildings (No footings below ground)**				0.00			0.00	0.00	0.00		0.00	0.00
8	**General Office/Stores Equip**	435,201.00			435,201.00	52,000.00		487,201.00	26,000.00	461,201.00	20%	92,240.20	394,960.80
10	**Computer Hardware/ Vehicles**	2,561,256.00			2,561,256.00	2,228,000.00		4,789,256.00	1,114,000.00	3,675,256.00	30%	1,102,576.80	3,686,679.20
10.1	**Certain Automobiles**				0.00			0.00	0.00	0.00		0.00	0.00
12	**Computer Software**				0.00	977,842.94		977,842.94	488,921.47	488,921.47	100%	488,921.47	488,921.47
13 1	**Lease # 1**				0.00			0.00	0.00	0.00		0.00	0.00
13 2	**Lease #2**				0.00			0.00	0.00	0.00		0.00	0.00
13 3	**Lease # 3**				0.00			0.00	0.00	0.00		0.00	0.00
13 4	**Lease # 4**				0.00			0.00	0.00	0.00		0.00	0.00
14	**Franchise**				0.00			0.00	0.00	0.00		0.00	0.00
17	**New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs**				0.00			0.00	0.00	0.00		0.00	0.00
43.1	**Certain Energy-Efficient Electrical Generating Equipment**				0.00			0.00	0.00	0.00		0.00	0.00
45	**Computers & Systems Hardware acq'd post Mar 22/04**	172,476.00			172,476.00			172,476.00	0.00	172,476.00	45%	77,614.20	94,861.80
45.1	**Computers & Systems Hardware acq'd post Mar 19/07**				0.00			0.00	0.00	0.00		0.00	0.00
46	**Data Network Infrastructure Equipment (acq'd post Mar 22/04)**				0.00			0.00	0.00	0.00		0.00	0.00
47	**Distribution System - post 22-Feb-2005**	86,098,379.00			86,098,379.00	28,725,414.89		114,823,793.89	14,362,707.45	100,461,086.45	8%	8,036,886.92	106,786,906.98
50	**Computer Hardware (post Mar 18, 2007)**	97,279.00			97,279.00	0.00		97,279.00	0.00	97,279.00	55%	53,503.45	43,775.55
52	**Computer Hardward - Post Jan 27, 2009, and before February 2011.**	0.00			0.00	791,000.00		791,000.00	0.00	791,000.00	100%	791,000.00	0.00
	SUB-TOTAL - UCC	**261,359,254.00**	**0.00**	**0.00**	**261,359,254.00**	**33,254,900.68**	**0.00**	**294,614,154.68**	**16,231,950.34**	**278,382,204.34**		**18,086,193.26**	**276,527,961.42**
CEC	**Goodwill**				0.00								
CEC	**Land Rights**	509,440.00			509,440.00								
CEC	**FMV Bump-up**				0.00								
	SUB-TOTAL - CEC	**509,440.00**	**0.00**	**0.00**	**509,440.00**								

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				509,440.00
Additions:				
Cost of Eligible Capital Property Acquired during the year	$ 336,248.04			
Other Adjustments				
Subtotal	$ 336,248.04	x 3/4 =	252,186.03	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002		x 1/2 =	-	
			252,186.03	761,626.03
Amount transferred on amalgamation or wind-up of subsidiary				-
Subtotal				761,626.03
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments				
Subtotal		x 3/4 =	0	761,626.03
Cumulative Eligible Capital Balance				761,626.03
CEC Deduction	7%			53,313.82
Cumulative Eligible Capital - Closing Balance				708,312.21

Table 2: CCA Continuity Schedule 2011

CCA Continuity Schedule (2011)													
Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV	UCC Bridge Year Opening Balance	Additions	Proceeds of Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	137,997,951.59			137,997,951.59	920,192.04		138,918,143.64	460,096.02	138,458,047.61	4%	5,538,321.90	133,379,821.73
2	Distribution System - pre 1988	25,067,574.08			25,067,574.08			25,067,574.08	0.00	25,067,574.08	6%	1,504,054.44	23,563,519.64
3	Buildings acquired before 1988	1,966,329.95			1,966,329.95			1,966,329.95	0.00	1,966,329.95	5%	98,316.50	1,868,013.45
6	Buildings (No footings below ground)	0.00			0.00			0.00	0.00	0.00		0.00	0.00
8	General Office/Stores Equip	394,960.80			394,960.80	146,500.00		541,460.80	73,250.00	468,210.80	20%	93,642.16	447,818.64
10	Computer Hardware/ Vehicles	3,686,679.20			3,686,679.20	2,282,000.00		5,968,679.20	1,141,000.00	4,827,679.20	30%	1,448,303.76	4,520,375.44
10.1	Certain Automobiles	0.00			0.00			0.00	0.00	0.00		0.00	0.00
12	Computer Software	488,921.47			488,921.47	521,533.90		1,010,455.37	260,766.95	749,688.42	100%	749,688.42	260,766.95
13 1	Lease # 1	0.00			0.00			0.00	0.00	0.00		0.00	0.00
13 2	Lease #2	0.00			0.00			0.00	0.00	0.00		0.00	0.00
13 3	Lease # 3	0.00			0.00			0.00	0.00	0.00		0.00	0.00
13 4	Lease # 4	0.00			0.00			0.00	0.00	0.00		0.00	0.00
14	Franchise	0.00			0.00			0.00	0.00	0.00		0.00	0.00
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0.00			0.00			0.00	0.00	0.00		0.00	0.00
43.1	Certain Energy-Efficient Electrical Generating Equipment	0.00			0.00			0.00	0.00	0.00		0.00	0.00
45	Computers & Systems Hardware acq'd post Mar 22/04	94,861.80			94,861.80			94,861.80	0.00	94,861.80	45%	42,687.81	52,173.99
45.1	Computers & Systems Hardware acq'd post Mar 19/07	0.00			0.00			0.00	0.00	0.00		0.00	0.00
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0.00			0.00			0.00	0.00	0.00		0.00	0.00
47	Distribution System - post 22-Feb-2005	106,786,906.98			106,786,906.98	16,673,647.41		123,460,554.39	8,336,823.71	115,123,730.68	8%	9,209,898.45	114,250,655.94
50	Computer Hardware (post Mar 18, 2007)	43,775.55			43,775.55	259,843.93		303,619.48	129,921.96	173,697.51	55%	95,533.63	208,085.84
52	Computer Hardward - Post Jan 27, 2009, and before February 2011.	0.00			0.00	23,622.18		23,622.18	11,811.09	11,811.09	100%	11,811.09	11,811.09
	SUB-TOTAL - UCC	276,527,961.42	0.00	0.00	276,527,961.42	20,827,339.46	0.00	297,355,300.88	10,413,669.73	286,941,631.15		18,792,258.17	278,563,042.71
CEC	Goodwill												0.00
CEC	Land Rights	708,312.21											708,312.21
CEC	FMV Bump-up												0.00
	SUB-TOTAL - CEC	708,312.21	0.00	0.00	708,312.21								

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				708,312.21
Additions:				
Cost of Eligible Capital Property Acquired during the year	$ 168,685.04			
Other Adjustments				
Subtotal	$ 168,685.04	x 3/4 =	126,513.78	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002		x 1/2 =	-	
			126,513.78	834,825.99
Amount transferred on amalgamation or wind-up of subsidiary				-
Subtotal				834,825.99
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments				
Subtotal		x 3/4 =	0	834,825.99
Cumulative Eligible Capital Balance				834,825.99
CEC Deduction	7%			58,437.82
Cumulative Eligible Capital - Closing Balance				776,388.17

Table 3: Determination of Tax Adjustments 2010

Determination of Tax Adjustments to Accounting Income for 2010				
Line Item	**T2S1 line #**	**Total for Legal Entity**	**Non-Distribution Eliminations**	**Utility Amount**
Additions:				
Interest and penalties on taxes	103			-
Amortization of tangible assets	104	10,863,414.11		10,863,414.11
Amortization of intangible assets	106	617,751.77		617,751.77
Recapture of capital cost allowance from Schedule 8	107			-
Gain on sale of eligible capital property from Schedule 10	108			-
Income or loss for tax purposes- joint ventures or partnerships	109			-
Loss in equity of subsidiaries and affiliates	110			-
Loss on disposal of assets	111			-
Charitable donations	112	2,650.00		2,650.00
Taxable Capital Gains	113			-
Political Donations	114			-
Deferred and prepaid expenses	116			-
Scientific research expenditures deducted on financial statements	118			-
Capitalized interest	119			-
Non-deductible club dues and fees	120			-
Non-deductible meals and entertainment expense	121	15,403.00		15,403.00
Non-deductible automobile expenses	122			-
Non-deductible life insurance premiums	123			-
Non-deductible company pension plans	124			-
Tax reserves beginning of year	125			-
Reserves from financial statements- balance at end of year	126	8,328,000.00		8,328,000.00
Soft costs on construction and renovation of buildings	127			-
Book loss on joint ventures or partnerships	205			-
Capital items expensed	206	276,138.00		276,138.00
Debt issue expense	208			-
Development expenses claimed in current year	212			-
Financing fees deducted in books	216			-
Gain on settlement of debt	220			-
Non-deductible advertising	226			-
Non-deductible interest	227			-
Non-deductible legal and accounting fees	228			-
Recapture of SR&ED expenditures	231			-
Share issue expense	235			-
Write down of capital property	236			-
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			-
Interest Expensed on Capital Leases	290			-
Realized Income from Deferred Credit Accounts	291			-
Pensions	292			-
Non-deductible penalties	293			-
Debt Financing Expenses for Book Purposes	294			-
Other Additions	295	44,746.00		44,746.00
Total Additions		**20,148,102.88**	**-**	**20,148,102.88**

1

2

Table 3: Determination of Tax Adjustments 2010 (continued)

Deductions:				
Gain on disposal of assets per financial statements	401			-
Dividends not taxable under section 83	402			-
Capital cost allowance from Schedule 8	403	18,086,193.26		18,086,193.26
Terminal loss from Schedule 8	404			-
Cumulative eligible capital deduction from Schedule 10	405	53,313.82		53,313.82
Allowable business investment loss	406			-
Deferred and prepaid expenses	409			-
Scientific research expenses claimed in year	411			-
Tax reserves end of year	413			-
Reserves from financial statements - balance at beginning of year	414	8,544,474.00		8,544,474.00
Contributions to deferred income plans	416			-
Book income of joint venture or partnership	305			-
Equity in income from subsidiary or affiliates	306			-
Interest capitalized for accounting deducted for tax	390			-
Capital Lease Payments	391			-
Non-taxable imputed interest income on deferral and variance accounts	392			-
Financing Fees for Tax Under S.20(1)(e)	393			-
Other Deductions	394	192,523.00		192,523.00
Total Deductions		**26,876,504.08**	**-**	**26,876,504.08**
Other Adjustments to Taxable Income				
Charitable donations from Schedule 2	311			-
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			-
Non-capital losses of preceding taxation years from Schedule 7-1	331			-
Net-capital losses of preceding taxation years from Schedule 7-1	332			-
Limited partnership losses of preceding taxation years from Schedule 4	335			-
Total Adjustments			**-**	**-**
Tax Adjustments to Accounting Income		**- 6,728,401.20**	**-**	**- 6,728,401.20**

1

Table 4: Determination of Tax Adjustments 2011

Determination of Tax Adjustments to Accounting Income for 2011				
Line Item	**T2S1 line #**	**Total for Legal Entity**	**Non-Distribution Eliminations**	**Utility Amount**
Additions:				
Interest and penalties on taxes	103			-
Amortization of tangible assets	104	10,924,906.93		10,924,906.93
Amortization of intangible assets	106	567,671.89		567,671.89
Recapture of capital cost allowance from Schedule 8	107			-
Gain on sale of eligible capital property from Schedule 10	108			-
Income or loss for tax purposes- joint ventures or partnerships	109			-
Loss in equity of subsidiaries and affiliates	110			-
Loss on disposal of assets	111			-
Charitable donations	112	2,650.00		2,650.00
Taxable Capital Gains	113			-
Political Donations	114			-
Deferred and prepaid expenses	116			-
Scientific research expenditures deducted on financial statements	118			-
Capitalized interest	119			-
Non-deductible club dues and fees	120			-
Non-deductible meals and entertainment expense	121	15,403.00		15,403.00
Non-deductible automobile expenses	122			-
Non-deductible life insurance premiums	123			-
Non-deductible company pension plans	124			-
Tax reserves beginning of year	125			-
Reserves from financial statements- balance at end of year	126	8,646,000.00		8,646,000.00
Soft costs on construction and renovation of buildings	127			-
Book loss on joint ventures or partnerships	205			-
Capital items expensed	206	276,138.00		276,138.00
Debt issue expense	208			-
Development expenses claimed in current year	212			-
Financing fees deducted in books	216			-
Gain on settlement of debt	220			-
Non-deductible advertising	226			-
Non-deductible interest	227			-
Non-deductible legal and accounting fees	228			-
Recapture of SR&ED expenditures	231			-
Share issue expense	235			-
Write down of capital property	236			-
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			-
Interest Expensed on Capital Leases	290			-
Realized Income from Deferred Credit Accounts	291			-
Pensions	292			-
Non-deductible penalties	293			-
Debt Financing Expenses for Book Purposes	294			-
Other Additions	295	44,746.00		44,746.00
Total Additions		**20,477,515.82**	**-**	**20,477,515.82**

1

2

Table 4: Determination of Tax Adjustments 2011 Continued

Deductions:				
Gain on disposal of assets per financial statements	401			-
Dividends not taxable under section 83	402			-
Capital cost allowance from Schedule 8	403	18,792,258.17		18,792,258.17
Terminal loss from Schedule 8	404			-
Cumulative eligible capital deduction from Schedule 10	405	58,437.82		58,437.82
Allowable business investment loss	406			-
Deferred and prepaid expenses	409			-
Scientific research expenses claimed in year	411			-
Tax reserves end of year	413			-
Reserves from financial statements - balance at beginning of year	414	8,328,000.00		8,328,000.00
Contributions to deferred income plans	416			-
Book income of joint venture or partnership	305			-
Equity in income from subsidiary or affiliates	306			-
Interest capitalized for accounting deducted for tax	390			-
Capital Lease Payments	391			-
Non-taxable imputed interest income on deferral and variance accounts	392			-
Financing Fees for Tax Under S.20(1)(e)	393			-
Other Deductions	394	192,523.00		192,523.00
Total Deductions		**27,371,218.99**	**-**	**27,371,218.99**
Other Adjustments to Taxable Income				
Charitable donations from Schedule 2	311			-
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			-
Non-capital losses of preceding taxation years from Schedule 7-1	331			-
Net-capital losses of preceding taxation years from Schedule 7-1	332			-
Limited partnership losses of preceding taxation years from Schedule 4	335			-
Total Adjustments		**-**	**-**	**-**
Tax Adjustments to Accounting Income		**- 6,893,703.17**	**-**	**- 6,893,703.17**

Table 5: Continuity of Reserves 2010 & 2011

CONTINUITY OF RESERVES FOR 2010

Description	Balance at December 31, Acutal Year as per tax returns	Non-Distribution Eliminations	Utility Only Opening Balance	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	Adjusted Utility Balance	Additions	Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)			0		0			0	0	
General reserve for bad debts			0		0			0	0	
Accrued Employee Future Benefits:	5,986,000		5,986,000		5,986,000	175,000		6,161,000	175,000	
- Medical and Life Insurance			0		0			0	0	
- Short & Long-term Disability			0		0			0	0	
- Accmulated Sick Leave			0		0			0	0	
- Termination Cost			0		0			0	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs	628,727		628,727		628,727		461,727	167,000	-461,727	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs	25,690		25,690		25,690		25,690	0	-25,690	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other	1,904,057		1,904,057		1,904,057	95,943		2,000,000	95,943	
Total	**8,544,474**	**0**	**8,544,474**	**0**	**8,544,474**	**270,943**	**487,417**	**8,328,000**	**-216,474**	**0**

CONTINUITY OF RESERVES FOR 2011

Description	Adjusted Utility Balance	Additions	Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0			0	0	
Tax Reserves Not Deducted for accounting purposes						
Reserve for doubtful accounts ss. 20(1)(l)	0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0			0	0	
Other tax reserves	0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)						
General Reserve for Inventory Obsolescence (non-specific)	0			0	0	
General reserve for bad debts	0			0	0	
Accrued Employee Future Benefits:	6,161,000	311,000		6,472,000	311,000	
- Medical and Life Insurance	0			0	0	
- Short & Long-term Disability	0			0	0	
- Accmulated Sick Leave	0			0	0	
- Termination Cost	0			0	0	
- Other Post-Employment Benefits	0			0	0	
Provision for Environmental Costs	167,000	7,000		174,000	7,000	
Restructuring Costs	0			0	0	
Accrued Contingent Litigation Costs	0			0	0	
Accrued Self-Insurance Costs	0			0	0	
Other Contingent Liabilities	0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0			0	0	
Other	2,000,000			2,000,000	0	
Total	**8,328,000**	**318,000**	**0**	**8,646,000**	**318,000**	**0**

Table 6: Capital Tax and Expense Schedules

2010 Capital Taxes		
Description	**OCT**	**LCT**
Total Rate Base	320,956,457	320,956,457
Exemption	-441,353	0
Deemed Taxable Capital	**320,515,104**	**320,956,457**
Rate	0.075%	0.000%
Gross Tax Payable	240,386	0
Surtax		
Net Capital Tax Payable	**240,386**	**0**

2010 PILs Schedule		
Description	**Source or Input**	**Tax Payable**
Accounting Income	10' Rev Def	12,841,059
Tax Adj to Accounting Income	10' Rev Def	(6,728,401)
Taxable Income		**6,112,658**
Combined Income Tax Rate	PILs Rates	31.000%
Total Income Taxes		**1,894,924**
Investment Tax Credits		
Miscellaneous Tax Credits		
Total Tax Credits		
Total PILs		**1,894,924**

2010 Total Taxes	
Description	**Tax Payable**
Total PILs	1,894,924
Net Capital Tax Payable	240,386
PILs including Capital Taxes	2,135,310

2011Capital Taxes		
Description	**OCT**	**LCT**
Total Rate Base	335,073,828	335,073,828
Exemption	0	0
Deemed Taxable Capital	**335,073,828**	**335,073,828**
Rate	0.000%	0.000%
Gross Tax Payable	**0**	0
Surtax		
Net Capital Tax Payable	**0**	**0**

2011 PILs Schedule		
Description	**Source or Input**	**Tax Payable**
Accounting Income	11' Rev Def	15,816,388
Tax Adj to Accounting Income	11' Rev Def	(6,893,703)
Taxable Income		**8,922,685**
Combined Income Tax Rate	PILs Rates	28.250%
Total Income Taxes		**2,520,658**
Investment Tax Credits		
Miscellaneous Tax Credits		
Total Tax Credits		
Total PILs		**2,520,658**

2011 Total Taxes	
Description	**Tax Payable**
Total PILs	2,520,658
Net Capital Tax Payable	-
PILs including Capital Taxes	2,520,658

FEDERAL AND PROVINCIAL TAX RETURNS FOR 2009

Appendix J of this document contains the 2009 federal and provincial tax returns for Hydro One Brampton Networks Inc., for reference as part of this Exhibit on the following pages.

APPENDIX I

CBNI 209.209
010-05-13 09:22

2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

200

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see www.cra.gc.ca or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 86486 7635 RC0001

Corporation's name
002 Hydro One Brampton Networks Inc.

Address of head office
Has this address changed since the last time you filed your T2 return? 010 1 Yes [ ] 2 No [X]
(If yes, complete lines 011 to 018.)
011 175 Sandalwood Parkway West
012
City: 015 Brampton
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 L7A 1E8

Mailing address (If different from head office address)
Has this address changed since the last time you filed your T2 return? 020 1 Yes [ ] 2 No [X]
(If yes, complete lines 021 to 028.)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

Location of books and records
Has the location of books and records changed since the last time you filed your T2 return? 030 1 Yes [ ] 2 No [X]
(If yes, complete lines 031 to 038.)
031
032
City: 035
Province, territory, or state: 036
Country (other than Canada): 037
Postal code/Zip code: 038

040 Type of corporation at the end of the tax year
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 YYYY MM DD

To which tax year does this return apply?
Tax year start 060 2009-01-01 YYYY MM DD
Tax year-end 061 2009-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes [ ] 2 No [X]
If yes, provide the date control was acquired 065 YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? 070 1 Yes [ ] 2 No [X]
Amalgamation? 071 1 Yes [ ] 2 No [X]
If yes, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes [ ] 2 No [X]
If yes, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If no, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes [ ] 2 No [ ]
If yes, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091 092 093 094 095 096
100

T2 E (09)

Canada

CORPORATE TAXREP / TAXPREP DES SOCIÉTÉS - EP12 VERSION 2009 V2.0

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **Yes** response, attach to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered yes to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	16
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	255		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1148
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter yes for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? 282

(Only complete if yes was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale 2 Retail

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distrib	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No X

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 (YYYY MM DD)

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300		15,272,231 A
Deduct: Charitable donations from Schedule 2	311	2,650	
Gifts to Canada, a province, or a territory from Schedule 2	312		
Cultural gifts from Schedule 2	313		
Ecological gifts from Schedule 2	314		
Gifts of medicine from Schedule 2	315		
Taxable dividends deductible under section 112 or 113, or subsection 138(6), from Schedule 3	320		
Part VI.1 tax deduction *	325		
Non-capital losses of previous tax years from Schedule 4	331		
Net capital losses of previous tax years from Schedule 4	332		
Restricted farm losses of previous tax years from Schedule 4	333		
Farm losses of previous tax years from Schedule 4	334		
Limited partnership losses of previous tax years from Schedule 4	335		
Taxable capital gains or taxable dividends allocated from a central credit union	340		
Prospector's and grubstaker's shares	350		
Subtotal		2,650 ▶	2,650 B
Subtotal (amount A minus amount B) (if negative, enter "0")			15,269,581 C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360		15,269,581
Income exempt under paragraph 149(1)(t)	370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 minus line 370)			15,269,581 Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . 400 15,272,231 A

Taxable income from line 360, minus 10/3 of the amount on line 632*, minus 3 times the amount on line 636**, and minus any amount that, because of federal law, is exempt from Part I tax . . . . . 405 15,269,581 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000 x (Number of days in the tax year before 2009 / Number of days in the tax year 365) = ... 1

500,000 x (Number of days in the tax year after 2008 365 / Number of days in the tax year 365) = 500,000 2

Add amounts at lines 1 and 2 500,000 4

Business limit (see notes 1 and 2 below) . . . . . 410 C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C x 415 *** 48,868,465 / 11,250 D = ... E

Reduced business limit (amount C minus amount E) (if negative, enter "0") . . . . 425 F

Small business deduction

Amount A, B, C, or F whichever is the least x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) x 16 % = 5

Amount A, B, C, or F whichever is the least x (Number of days in the tax year after December 31, 2007 365 / Number of days in the tax year 365) x 17 % = 6

Total of amounts 5 and 6 – enter on line 9 430 G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360						15,269,581	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27							B
Amount QQ from Part 13 of Schedule 27							C
Amount used to calculate the credit union deduction from Schedule 17							D
Amount from line 400, 405, 410, or 425, whichever is the least							E
Aggregate investment income from line 440							F
Total of amounts B to F					▶		G
Amount A minus amount G (if negative, enter "0")						15,269,581	H
Amount H	15,269,581	x Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x	7 %	=	I
Amount H	15,269,581	x Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year		x	8.5 %	=	J
Amount H	15,269,581	x Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365 / 365	x	9 %	= 1,374,262	K
Amount H	15,269,581	x Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x	10 %	=	L
General tax reduction for Canadian-controlled private corporations – Total of amounts I to L Enter amount M on line 638.						1,374,262	M

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)							N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27							O
Amount QQ from Part 13 of Schedule 27							P
Amount used to calculate the credit union deduction from Schedule 17							Q
Total of amounts O to Q					▶		R
Amount N minus amount R (if negative, enter "0")							S
Amount S		x Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x	7 %	=	T
Amount S		x Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year		x	8.5 %	=	U
Amount S		x Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365 / 365	x	9 %	=	V
Amount S		x Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x	10 %	=	W
General tax reduction – Total of amounts T to W Enter amount X on line 639							X

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 — 440 _____ × 26 2 / 3 % = _____ A

Foreign non-business income tax credit from line 632 _____

Deduct:
Foreign investment income from Schedule 7 — 445 _____ × 9 1 / 3 % = _____ (If negative, enter "0") _____ B

Amount A **minus** amount B (if negative, enter "0") _____ C

Taxable income from line 360 — 15,269,581

Deduct:
Amount from line 400, 405, 410, or 425, whichever is the least _____
Foreign non-business income tax credit from line 632 _____ × 25 / 9 = _____
Foreign business income tax credit from line 636 _____ × 3 = _____

15,269,581
× 26 2 / 3 % = 4,071,888 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) — 2,891,820

Deduct: Corporate surtax from line 600 _____

Net amount — 2,891,820 — 2,891,820 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least — 450 _____ F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year — 460 _____

Deduct: Dividend refund for the previous tax year — 465 _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above _____

Total Part IV tax payable from Schedule 3 _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation — 480 _____ H

Refundable dividend tax on hand at the end of the tax year Amount G **plus** amount H — 485 _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3 _____ × 1 / 3 _____ I

Refundable dividend tax on hand at the end of the tax year from line 486 above _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) _____

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied by** 38.00 %	550	5,802,441	A

Corporate surtax calculation

Base amount from line A above		5,802,441	1
Deduct:			
10 % of taxable income (line 360 or amount Z, whichever applies)		1,525,958	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28.00 % of taxable income from line 360	a		
28.00 % of taxed capital gains	b		6
Part I tax otherwise payable (line A plus lines C and D minus line F)	c		
Total of lines 2 to 6		1,526,958	7
Net amount (line 1 minus line 7)		4,275,483	8

Corporate surtax*

Line 8 4,275,483 × (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 × 4 % = 600 B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31	602		C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			I
Taxable income from line 360	15,269,581		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	15,269,581 ▶	15,269,581	II
Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount I or II	604		D
Subtotal (add lines A to D)		5,802,441	E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608	1,526,958	
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount M	638	1,374,262	
General tax reduction from amount X	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	9,401	
Subtotal		2,910,621 ▶	2,910,621 F
Part I tax payable – Line E minus line F			2,891,820 G

Enter amount G on line 700.

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2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

Summary of tax and credits

Federal tax

Part I tax payable	700	2,891,820
Part I surtax payable from Schedule 40	708	
Part II.1 tax payable from Schedule 55	710	
Part V tax payable from Schedule 3	712	
Part V.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		2,891,820

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760	2,697,040	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		2,697,040 ▶	2,697,040
Total tax payable	770		5,588,860 A

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit: refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	7,532,274	
Total credits	890	7,532,274 ▶	7,532,274 B

Refund code 894 2 Overpayment 1,943,414

Balance (line A minus line B) -1,943,414

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number

918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 PAUL Last name in block letters 951 TONY First name in block letters 954 CONTROLLER Position, office, or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2010-03-31 Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (905) 452-5505 Telephone number

Is the contact person the same as the authorized signing officer? If no, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name in block letters

959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering 1 for English or 2 for French.
Indiquez votre langue de correspondance en inscrivant 1 pour anglais ou 2 pour français.

990 1

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI) for Corporations* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule, and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant preparing or reporting on the financial statements

Does the accountant have a professional designation?	095	1 Yes [X]	2 No [ ]
Is the accountant connected* with the corporation?	097	1 Yes [ ]	2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant:

	196	
Completed an auditor's report	1	[X]
Completed a review engagement report	2	[ ]
Conducted a compilation engagement	3	[ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation?	099	1 Yes [ ]	2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options:

	110	
Prepared the tax return (financial statements prepared by client)	1	[X]
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	[ ]

Were notes to the financial statements prepared?	101	1 Yes [X]	2 No [ ]
If **yes**, complete lines 102 to 107 below:			
Are any values presented at other than cost?	102	1 Yes [ ]	2 No [X]
Has there been a change in accounting policies since the last return?	103	1 Yes [X]	2 No [ ]
Are subsequent events mentioned in the notes?	104	1 Yes [ ]	2 No [X]
Is re-evaluation of asset information mentioned in the notes?	105	1 Yes [ ]	2 No [X]
Is contingent liability information mentioned in the notes?	106	1 Yes [X]	2 No [ ]
Is information regarding commitments mentioned in the notes?	107	1 Yes [X]	2 No [ ]
Does the corporation have investments in joint venture(s) or partnership(s)?	108	1 Yes [ ]	2 No [X]
If **yes**, complete line 109 below:			
Are you filing financial statements of the joint venture(s) or partnership(s)?	109	1 Yes [ ]	2 No [ ]

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Hydro One Brampton Networks Inc
86486 7635 RC0001

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES — SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				10,415,197 A
Add:				
Provision for income taxes – current		101	5,301,152	
Provision for income taxes – deferred		102	3,097,195	
Interest and penalties on taxes		103	14,472	
Amortization of tangible assets		104	17,447,046	
Charitable donations and gifts from Schedule 2		112	2,650	
Non-deductible meals and entertainment expenses		121	15,403	
Reserves from financial statements – balance at the end of the year		126	15,603,561	
	Subtotal of additions		41,481,479 ▶	41,481,479
Other additions:				
Miscellaneous other additions:				
600 Depreciation expensed via OM&A		290	276,138	
601 Add back capital tax accrued		291	938,034	
602 Federal apprenticeship credit and ITC-2008 taxed in 2009		292	11,685	
603 Specified credits not included in income	33,605			
Accretion and Reval of Environmental Costs	464,245			
Total	497,850	293	497,850	
604 Amortization of debt discount	11,141			
Total	11,141	294	11,141	
	Subtotal of other additions	199	1,734,848 ▶	1,734,848
	Total additions	500	43,216,327 ▶	43,216,327
Deduct:				
Capital cost allowance from Schedule 8		403	15,470,309	
Cumulative eligible capital deduction from Schedule 10		405	1,844,213	
Reserves from financial statements – balance at the beginning of the year		414	20,059,448	
	Subtotal of deductions		37,373,970 ▶	37,373,970
Other deductions:				
Miscellaneous other deductions:				
700 Deduct OPEB costs capitalized		390	197,573	
701 Deduct actual capital tax per Schedule 515		391	614,388	
702 2009 ITC recorded-to be taxed in 2010		392	9,400	
704 Removal costs	169,012			
Total	169,012	394	169,012	
	Subtotal of other deductions	499	985,323 ▶	985,323
	Total deductions	510	38,359,293 ▶	38,359,293
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				15,272,231

* For reference purposes only

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SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Brampton Safe City	2,500
Subtotal	2,500
Add: Total donations of less than $100 each	150
Total donations in current tax year	2,650

		Federal	Quebec	Alberta
Charitable donations at the end of the previous tax year				
Deduct: Charitable donations expired after five tax years	239			
Charitable donations at the beginning of the tax year	240			
Add:				
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250			
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) 210 2,650				
Subtotal (line 250 plus line 210)		2,650	2,650	2,650
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		2,650 A	2,650	2,650
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	2,650	2,650	2,650
Charitable donations closing balance	280			

Amounts carried forward – Charitable donations

Year of origin:		Federal	Quebec	Alberta
1st prior year	2008			
2nd prior year	2007			
3rd prior year	2006			
4th prior year	2005			
5th prior year	2004			
6th prior year *	2003			
Total (to line A)				

* These donations expired in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % ..... 11,454,173 B

Taxable capital gains arising in respect of gifts of capital property included in Part 1 ** 225 ____ C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ..... 227 ____ D

The amount of the recapture of capital cost allowance in respect of charitable gifts ..... 230 ____

Proceeds of disposition, less outlays and expenses ** ..... ____ E

Capital cost ** ..... ____ F

Amount E or F, whichever is less ..... 235 ____

Amount on line 230 or 235, whichever is less ..... ____ G

Subtotal (**add** amounts C, D, and G) ____ H

Amount H **multiplied** by 25 % ____ I

Subtotal (amount B **plus** amount) 11,454,173 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) ..... 2,650 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year .....

Deduct: Gifts to Canada, a province, or a territory expired after five tax years ..... 339 ____

Gifts to Canada, a province, or a territory at the beginning of the tax year ..... 340 ____ ▶ ____

Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the wind-up of a subsidiary ..... 350 ____

Total current-year gifts made to Canada, a province, or a territory * ..... 310 ____

Subtotal (line 350 **plus** line 310) ____

Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004) ..... 355 ____

Total gifts to Canada, a province, or a territory available .....

Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return). ..... 360 ____

Gifts to Canada, a province, or a territory closing balance ..... 380 ____

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Quebec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Quebec	Alberta
1st prior year	2008			
2nd prior year	2007			
3rd prior year	2006			
4th prior year	2005			
5th prior year	2004			
6th prior year *	2003			
Total				

* These donations expired in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Quebec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Quebec	Alberta
1st prior year	2008			
2nd prior year	2007			
3rd prior year	2006			
4th prior year	2005			
5th prior year	2004			
6th prior year *	2003			
Total				

* These donations expired in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal	Quebec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639			
Additional deduction for gifts of medicine at the beginning of the tax year	640			
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650			
Additional deduction for gifts of medicine for the current year:				
Proceeds of disposition	602	1	1	1
Cost of gifts of medicine	601	2	2	2
Subtotal (line 1 **minus** line 2)		3	3	3
Line 3 **multiplied** by 50 %		4	4	4
Eligible amount of gifts	600	5	5	5

Federal: A _____ × (B _____ / C) = Additional deduction for gifts of medicine for the current year 610 _____

Quebec: A _____ × (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

Alberta: A _____ × (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

Where:
A is the **lesser** of line 2 and line 4
B is the eligible amount of gifts (line 600)
C is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Quebec	Alberta
1st prior year	2008			
2nd prior year	2007			
3rd prior year	2006			
4th prior year	2005			
5th prior year	2004			
6th prior year *	2003			
Total				

* These donations expired in the current year.

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Hydro One Brampton Networks Inc.
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1); or
  - is claiming provincial or territorial tax credits or rebates (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations*.
- For more information, see the *T2 Corporation – Income Tax Guide*.
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 402 Corporations not specified — Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes X	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking center, the taxable income is the amount on line 360 or line Z of the T2 return plus the total amount not required to be included, or minus the total amount not allowed to be deducted, in computing the corporation's income under section 33.1 of the federal *Income Tax Act*.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see line 760 of the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2 on the following pages.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
15,269,581			2,137,741

Ontario basic income tax (from Schedule 500)	270	2,137,741		
Deduct: Ontario small business deduction (from schedule 500)	402			
Subtotal (if negative, enter "0")		2,137,741	▶	2,137,741 A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272			
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 503)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal			▶	B6
Subtotal (amount A6 plus amount B6)				2,137,741 C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414	368		
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal		368	▶	368 D6
Subtotal (amount C6 minus amount D6) (if negative, enter "0")				2,137,373 E6
Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 minus amount on line 416) (if negative, enter "0")				2,137,373 F6
Deduct:				
Ontario corporate minimum tax credit (from schedule 510)	418			
Ontario corporate income tax payable (amount F6 minus amount on line 418) (if negative, enter "0")				2,137,373 G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282	614,388		
Subtotal		614,388	▶	614,388 H6
Total Ontario tax payable before refundable credits (amount G6 plus amount H6)				2,751,761 I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	14,613		
Ontario apprenticeship training tax credit (from Schedule 552)	454	40,108		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Subtotal		54,721	▶	54,721 J6
Net Ontario tax payable or refundable credit (amount I6 minus amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290			2,697,040 K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories at line 255.

Net provincial and territorial tax payable or refundable credits	255	2,637,040

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? 101 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost 212	8 CCA rate % 213	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 multiplied by column 8 or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11) 220
1.	1		148,613,817	602,472		2,527	299,073	148,913,780	4	0	0	5,956,552	143,257,210
2.	2		28,369,821			0		28,369,821	6	0	0	1,702,189	26,667,632
3.	8		544,001			0		544,001	20	0	0	108,800	435,201
4.	10		2,288,441	1,135,009		6,365	564,322	2,852,763	30	0	0	855,829	2,561,256
5.	45		313,592			0		313,592	45	0	0	141,116	172,476
6.	12		92,016			0		92,016	100	0	0	92,016	
7.	47		67,064,647	25,417,251		1,726	12,707,763	79,772,403	8	0	0	6,381,793	86,068,379
8.	3		2,178,759			0		2,178,759	5	0	0	108,938	2,069,821
9.	50		216,175			0		216,175	55	0	0	118,896	97,279
10.	52			4,180		0		4,180	100	0	0	4,180	
		Total	249,681,269	27,158,912		10,618	13,571,058	263,257,505				15,470,309	261,359,254

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%) class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 366 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (08)

Canada

Hydro One Brampton Networks Inc.
EB-2010-0312
Exhibit 4
Tab 8
Schedule 1.2
Appendix I
Filed: 30-June-2010

Hydro One Brampton Networks Inc. **Sch.08**
Account/ Business No.: 864867635 **Year Ended: 2009-12-31** **Supplementary**

Subsection 13(7.4) Election

Included in this return is an election under subsection 13(7.4) with respect to amounts that would normally be included in income under paragraph 12(1)(x). The amount in respect of which the election was made, and so was not included in income but was the amount by which the cost of depreciable property was reduced, is $12,834,481.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Hydro One Inc.		86999 4731 RC0001	1	2,000	100.000			51,501,400
2.	Hydro One Networks Inc.		87086 5821 RC0001	3					
3.	Hydro One Remote Communities In		87083 6269 RC0001	3					
4.	Hydro One Telecom Inc.		86800 1066 RC0001	3					
5.	Hydro One Telecom Link Limited		88786 7513 RC0001	3					
6.	Hydro One Lake Erie Link Managem		87892 1519 RC0001	3					
7.	Hydro One Lake Erie Link Company		87560 6519 RC0001	3					

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

T2 SCH 9(99)

Canada

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Hydro One Brampton Networks Inc
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	26,328,476 A
Add: Cost of eligible capital property acquired during the taxation year	222	23,226			
Other adjustments	226				
Subtotal (line 222 plus line 226)		23,226	x 3 / 4 =	17,420 B	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 =	C	
amount B minus amount C (if negative, enter "0")			17,420 ▶		17,420 D
Amount transferred on amalgamation or wind-up of subsidiary				224	E
Subtotal (add amounts A, D, and E)				230	26,345,896 F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242			G	
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244			H	
Other adjustments	246			I	
(add amounts G,H, and I)			x 3 / 4 =	248	J
Cumulative eligible capital balance (amount F minus amount J)					26,345,896 K
(if amount K is negative, enter "0" at line M and proceed to Part 2)					
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business	249				
amount K	26,345,896				
less amount from line 249					
Current year deduction	26,345,896	x 7.00 % =	250	1,844,213 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				1,844,213 ▶	1,844,213 L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	24,501,683 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

T2 SCH 10 (04)

Canada

Part 2 – Amount to be included in income arising from disposition
(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")		▶		O
Line N minus line O (if negative, enter "0")				P
Line P minus line Q (if negative, enter "0")	Line 5 × 1 / 2 =			Q
	Amount R × 2 / 3 =			S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB	5,739,000		247,000		5,986,000
2	Legal Claim Provision	2,500		23,190		25,690
3	Allow. for Doubtful Accounts					
4	Regulatory Accounts	11,663,080			4,603,993	7,059,087
5	Other Regulatory Liabilities	1,100,000				1,100,000
6	Environmental Liabilities	1,554,868			926,141	628,727
7	Other Deferred Credits			804,057		804,057
	Reserves from Part 2 of Schedule 13					
	Totals	20,059,448		1,074,247	5,530,134	15,603,561

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 15

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by (see note 3) (EPSP only) 600
1	1	1,117,276	0345983	Ontario Municipal Employees Retirement Sy	1 University Ave Suite 1000 Toronto ON CA M5J 2P1	2

Note 1: Enter the applicable code number:
1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	1,117,276	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	1,117,276	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")		C

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

T2 SCH 15 (09)

Canada

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2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General Information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward for credits earned in tax years that end after 1997 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - qualified expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return*.
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures*.
7. For information on SR&ED, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Pamphlet T4052, *An Introduction to the Scientific Research and Experimental Development Program*; and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed Information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures made after February 22, 2005, the expression "in Canada" includes the "exclusive economic zone" (as defined in the Oceans Act to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone. For SR&ED expenditures made before February 23, 2005, the expression "in Canada" generally includes the 12 nautical mile territorial sea.

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

Part 1 – Investments, expenditures and percentages

Investments	Specified percentage
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC) throughout the tax year, this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC throughout the current tax year that incurred qualified expenditures for SR&ED in any area in Canada after 1995	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures after 2004:	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment after May 1, 2006	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? 101 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC throughout the current tax year and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its qualifying income limit for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC for tax years ending after March 22, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a 100% refund on your share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are not qualifying corporations may also earn a 100% refund on their share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the 40% refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? 102 1 Yes ☐ 2 No ☒

If yes, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*. Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province) 120	Amount of investment 125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired* 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 _____ x 10 % = 240

Credit allocated from a partnership 250

Subtota ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line 61 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 760 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures

Current expenditures (from line 577 on Form T661) . . . . . _____

Add:

Contributions to agricultural organizations for SR&ED under paragraph 37(1)(a)* . . . . . _____

Deduct:

Government and non-government assistance* . . . . . _____

Contributions to agricultural organizations for SR&ED* . . . . . _____ ▶ _____

Current expenditures (including contributions to agricultural organizations for SR&ED)* . . . . . ▶ 350 _____

Capital expenditures . . . . . 360 _____

Repayments made in the year (from line 560 on Form T661) . . . . . 370 _____

Total (this must equal the amount from line 570 on Form T661)* . . . . . 380 _____

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC throughout the current tax year.

Note: A CCPC that calculates SR&ED expenditure limit for tax years ending after March 22, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . . 385 1 Yes ☐ 2 No ☒

Complete lines 390, 395 and 398, if you answered no to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the previous tax year* (prior to any loss carry backs applied). 390 25,344,864

b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return). . . . . 395 _____

c) Enter your taxable capital employed in Canada for the previous tax year 146,057,423 minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. 398 40,000,000

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC throughout the current tax year

For stand-alone corporations:

Calculation 1: tax year ends before February 26, 2008.
[($6,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) divided by line 4 on page 4 of the T2 return)] . . . . . _____

Calculation 2: tax year starts after February 25, 2008 and ends before January 1, 2010.
[($7,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 minus line 398 from Part 9) divided by $40,000,000)] . . . . . _____

Calculation 3: tax year includes February 26, 2008.
AA + [(BB minus AA) x (CC divided by DD)] where,

AA = [($6,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x ((line 395 from Part 9) divided by line 4 on page 4 of the T2 return)];

BB = [($7,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 minus line 398 from Part 9) divided by $40,000,000)];

CC = number of days in the tax year after February 25, 2008;

DD = number of days in the tax year. . . . . _____

Calculation 4: tax year starts after December 31, 2009.
[($8,000,000 minus (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 minus line 398 from Part 9) divided by $40,000,000)] . . . . . _____

Calculation 5: tax year includes January 1, 2010.
EE + [(FF minus EE) x (GG divided by HH)] where,

EE = [($7,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 minus line 398 from Part 9) divided by $40,000,000)];

FF = [($8,000,000 minus (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 minus line 398 from Part 9) divided by $40,000,000)].

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year. . . . . _____

Enter the amount from Calculation 1, 2, 3, 4 or 5, whichever is applicable _____ *G

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . . 400 _____ *H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H _____ x Number of days in the tax year _____ / 365 = ... _____ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . . 410 _____

* Amount G or H cannot be more than $3,000,000 ($2,000,000 if tax year ending before February 26, 2008).

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 % =	J
Line 350 minus line 410 (if negative, enter "0")	430		x	20 % =	K
Line 410 minus line 350 (if negative, enter "0")		L			
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 % =	M
Line 360 minus line L (if negative, enter "0")	450		x	20 % =	N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 % =	
480		x	20 % =	
			Total ▶	O

Current year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12)

* For corporations that are not CCPCs throughout the year, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations	510		
Credit expired*	515		
Subtotal ▶			
ITC at the beginning of the tax year	520		

Add:

Credit transferred on amalgamation or wind-up of subsidiary	530		
Total current-year credit	540		
Credit allocated from a partnership	550		
Subtotal ▶			

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line 82 in Part 30)	560		
Credit carried back to the previous year(s) (from Part 13)		P	
Credit transferred to offset Part VII tax liability	580		
Subtotal ▶			

Credit balance before refund Q

Deduct:

Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)	610	

ITC closing balance on SR&ED 620

* The credit expires after 20 tax years if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86186 7635 RC0001	2009-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 10?.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes ☐ 2 No ☒

Credit balance before refund (amount C from Part 12) . . . . . R

Current-year ITC (lines 540 plus 550 from Part 12 minus line O from Part 11) . . . . . S

Refundable credits (amount R or S, whichever is less)* . . . . . T

Amount J from Part 11 . . . . . U

Subtract: Amount T or U, whichever is less V

Net amount (if negative, enter "0") . . . . . W

Amount W _____ x 40 % X

Add: Amount V . . . . . Y

Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12) . . . . . Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) . . . . . AA

Amount J from Part 11 . . . . . BB

Subtract: Amount AA or BB, whichever is less CC

Net amount (if negative, enter "0") . . . . . DD

Amount M from Part 11 . . . . . EE

Amount DD or EE, whichever is less _____ x 40 % . . . . . FF

Add : Amount CC above . . . . . GG

Refund of ITC (amounts FF **plus** GG) . . . . . HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when all of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ____ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D	E	F
Amount determined by the formula (A x B) - C	ITC carried by the transferee for the qualified expenditures that were transferred 750	Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) _____ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 650 in Part 12 on page 6. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) 760 _____ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16	LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above	MM
Recaptured ITC for calculation 3 from line KK in Part 16 above	NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN. Enter amount OO at line A1 in Part 29.	OO

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts in column 826		►	VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:
- Credit deemed as a remittance of co-op corporations — 841
- Credit expired* — 845

Subtotal ▶ 850

ITC at the beginning of the tax year

Add:
- Credit transferred on amalgamation or wind-up of subsidiary — 860
- Expenditures from line YY in Part 18 — 870 _____ x 10 % = 880

Total credit available

Deduct:
- Credit deducted from Part I tax (enter on line B3 in Part 30) — 885
- Credit carried back to the previous year(s) (from Part 20) — CCC

Subtotal ▶ 890

ITC closing balance from pre-production mining expenditures

* The credit is eligible for a 20 year carryforward effective for credits earned in 2003 and later tax years.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for the tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) ..... 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages or $2,000.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	PD1787( )	434A	57,315	5,732	2,000
2.	PA6226( )	434A	53,855	5,386	2,000
3.	PA4072( )	434A	14,887	1,489	1,489
4.	PA4124( )	434A	16,546	1,655	1,655
5.	PA9032( )	434A	2,568	257	257
6.	D19239( )	434A	61,980	6,198	2,000
				Total current-year credit (enter at line 640)	9,401

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	612		
Credit expired after 20 tax years	615		
	Subtotal		▶
ITC at the beginning of the tax year	625		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	630		
ITC from repayment of assistance	635		
Total current-year credit (total of column 605)	640	9,401	
Credit allocated from a partnership	655		
	Subtotal	9,401	▶ 9,401
Total credit available			9,401
Deduct:			
Credit deducted from Part I tax (enter on line B4 in Part 30)	660	9,401	
Credit carried back to the previous year(s) (from Part 23)			DDD
	Subtotal	9,401	▶ 9,401
ITC closing balance from apprenticeship job creation expenditures	690		

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

Carryback of this credit is restricted to tax years ending after May 1, 2006.

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property), and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year 715 _____ EEE

Add: Specified child care start-up expenditures from the current tax year . . . . . 705 _____ FFF

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . _____ GGG

Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) . . . . . 725 _____ HHH

Excess (amount GGG **minus** amount HHH) (if negative, enter "0") _____ III

Add: Repayments of government and non-government assistance . . . . . 735 _____ JJJ

Total eligible expenditures for child care spaces (amount III **plus** amount JJJ) . . . . . 745 _____

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 740)			×	25 %	=	KKK
Number of child care spaces	755		× $	10,000	=	LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)						MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal		▶	
ITC at the beginning of the tax year	775		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	777		
Total current-year credit (amount MMM above)	780		
Credit allocated from a partnership	782		
Subtotal		▶	
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B5 in Part 30)	785		
Credit carried back to the previous year(s) (from Part 27)		NNN	
Subtotal		▶	
ITC closing balance from child care spaces expenditures	790		

Part 27 – Request for carryback of credit from child care space expenditures

	Year	Month	Day			
1st previous tax year	2008	12	31	Credit to be applied	941	
2nd previous tax year	2007	12	31	Credit to be applied	942	
3rd previous tax year	2006	12	31	Credit to be applied	943	
				Total (enter on line NNN in Part 26)		

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 80 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . 792 _____ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . 795 _____

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . . 797 _____

Amount from line 795 or line 797, whichever is less . . . . . _____ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26 on page 13. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC 799 _____ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . _____ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 7 . . . . . _____ A1

Recaptured child care spaces ITC from line QQQ in Part 28 above . . . . . _____ A2

Total recapture of investment tax credit – Add lines A1 and A2
Enter amount A3 on line 602 of the T2 return. . . . . _____ A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) . . . . . _____ B1

ITC from SR&ED expenditures deducted from Part I tax (from line 660 in Part 12) . . . . . _____ B2

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) . . . . . _____ B3

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) 9,401 B4

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) . . . . . _____ B5

Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) 9,401 B6
Enter amount B6 at line 852 of the T2 return.

HOBNI 209.209
2010-06-13 09:26

2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 33

PART I.3 TAX ON LARGE CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- File this schedule if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- Even if there is no Part I.3 tax payable for the days in the tax year that are after 2005, you must still complete this schedule (except parts 5 and 9).
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms "financial institution," "long-term debt," and "reserves."
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- No Part I.3 tax is payable for a tax year by a corporation that was:
  1) bankrupt (as defined by subsection 128(3)) at the end of the year;
  2) a deposit insurance corporation throughout the year, as defined by subsection 137.1(5), or deemed to be a deposit insurance corporation by subsection 137.1(5.1);
  3) exempt from tax under section 149 throughout the year on all of its taxable income;
  4) neither resident in Canada nor carrying on a business through a permanent establishment in Canada at any time in the year; or
  5) a corporation described in subsection 136(2) throughout the year, the principal business of which was marketing (including any related processing) natural products belonging to or acquired from its members or customers.
- File the completed Schedule 33 with the *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- This schedule may contain changes that had not yet become law at the time of printing.

If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, "Taxable capital employed in Canada."

Part 1 – Capital

Add the following amounts at the end of the year:			
Reserves that have not been deducted in computing income for the year under Part I	101	15,603,551	
Capital stock (or members' contributions if incorporated without share capital)	103	51,501,490	
Retained earnings	104	55,522,232	
Contributed surplus	105		
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	164,982,131	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
Proportion of the amount, if any, by which the total of all amounts (see note below) for the partnership of which the corporation is a member at the end of the year exceeds the amount of the partnership's deferred unrealized foreign exchange losses	112		
	Subtotal	287,609,414 ▶	287,609,414 A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121	14,106,618	
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123		
The amount of deferred unrealized foreign exchange losses at the end of the year	124		
	Subtotal	14,106,618 ▶	14,106,618 B
Capital for the year (amount A minus amount B) (if negative, enter "0")	190		273,502,796

Note: Lines 101, 107, 108, 109, 111, and 112 are determined as follows:
- If the partnership is a member of another partnership (tiered partnerships), include the amounts of the partnership and tiered partnerships.
- Amounts for the partnership and tiered partnerships are those that would be determined for lines 101, 107, 108, 109, 111, and 112 as if they apply in the same way that they apply to corporations.
- Do not include amounts owing to the member or to other corporations that are members of the partnership.
- Amounts are determined at the end of the last fiscal period of the partnership ending in the year of the corporation.
- The proportion of the total amounts is determined by the corporation's share of the partnership's income or loss for the fiscal period of the partnership.

Canada

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(c)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   - the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   - the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   - the carrying value of a partnership member's interest at the end of the year is its specified proportion (as defined in subsection 248(1)) of the partnership's investment allowance.
2. Lines 401 to 406 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)		273,502,796 C
Deduct: Investment allowance for the year (line 490)		D
Taxable capital for the year (amount C minus amount D) (if negative, enter "0")	500	273,502,796

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 273,502,796 × (Taxable income earned in Canada 610 / Taxable income) 15,269,581 / 15,269,581 = **Taxable capital employed in Canada** 690 273,502,796

Notes:

1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business it carried on during the year through a permanent establishment in Canada	701	
Deduct the following amounts:		
Corporation's indebtedness at the end of the year (other than indebtedness described in any of paragraphs 181.2(3)(c) to (*)) that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711	
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712	
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713	
Total deductions (add lines 711, 712, and 713)	▶	E
Taxable capital employed in Canada (line 701 minus amount E) (if negative, enter "0")	790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation of gross Part 1.3 tax

If the tax year starts after 2005, do not complete this part.

Taxable capital employed in Canada (line 690 or 790, whichever applies) 273,502,796

Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36) 1,471,177

Excess of taxable capital employed in Canada over capital deduction 811

Line 811 _____ x Number of days in the tax year in 2004 / Number of days in the tax year 365 x 0.002 = ... F

Line 811 _____ x Number of days in the tax year in 2005 / Number of days in the tax year 365 x 0.00175 = ... G

Note: The Part I.3 tax rate is reduced to 0% for the days in the tax year that are after 2005.

Subtotal (add amounts F and G) _____ H

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax as follows:

Amount H _____ x Number of days in the year (365) / 365 = ... I

Gross Part I.3 tax (amount H or I, whichever applies) 820

Part 6 – Calculation of gross Part I.3 tax for purposes of the unused surtax credit

Taxable capital employed in Canada (line 690 or 790, whichever applies) ..... 273,502,796 J

Deduct: Capital deduction claimed for the year (enter $50,000,000 or, for related corporations, the amount allocated on Schedule 36) ..... 801 1,471,177 x 1/5 = 294,235 K

Excess (amount J minus amount K) (if negative, enter "0") 273,208,561 L

Amount L 273,208,561 x 0.00225 = ... 614,719 M

Where the tax year of a corporation is less than 51 weeks, calculate the amount of gross Part I.3 tax for purposes of the unused surtax credit as follows:

Amount M 614,719 x Number of days in the year (365) / 365 = ... N

Gross Part I.3 tax for purposes of the unused surtax credit (amount M or N, whichever applies) 821 614,719

Part 7 – Calculation of current-year surtax credit available

- Corporations can claim a credit against their Part I.3 tax for the amount of Canadian surtax payable for the year. This is called the surtax credit.
- Any unused surtax credit can be carried back three years or carried forward seven years. Unused surtax credits must be applied in order of the oldest first.
- Refer to subsection 181.1(7) when calculating the amount deductible for a corporation's unused surtax credits where control of the corporation has been acquired between the year in which the credits arose and the year in which you want to claim them.

For a corporation that was a non-resident of Canada throughout the year, enter amount a or b at line O, whichever is less:

a) line 600 from the T2 return . . . . . a

b) line 700 from the T2 return . . . . . b ____ O

In any other case, enter amount c or d at line P, whichever is less:

c) line 600 from the T2 return ____ x (line 690 of this schedule 273,502,796 / line 500 of this schedule 273,502,796) = ____ c

d) line 700 from the T2 return . . . . . 2,891,820 d ____ P

Current-year surtax credit available (amount O or P, whichever applies) . . . . . 830 ____

Part 8 – Calculation of current-year unused surtax credit

Current-year surtax credit available (line 830) . . . . . ____

Less: Gross Part I.3 tax for purposes of the unused surtax credit (line 321) 614,719

Current-year unused surtax credit (if negative, enter "0") . . . . . 850 ____

Enter this amount at line 600 on Schedule 37.

Part 9 – Calculation of net Part I.3 tax payable

If the tax year starts after 2005, do not complete this part.

Gross Part I.3 tax (line 820) . . . . . Q

Deduct:

Current-year surtax credit applied (line 820 or 830, whichever is less) . . . . . 861 ____

Unused surtax credit from previous years applied (amount from line 320 on Schedule 37) . . . . 862 ____

Subtotal (cannot be more than amount on line 820) ____ ▶ ____ R

Net Part I.3 tax payable (amount Q minus amount R) . . . . . 870 ____

Enter this amount at line 704 of the T2 return.

Part 10 – Calculation for purposes of the small business deduction

This part is applicable only to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies) . . . . . S

Deduct:

Capital deduction claimed for the year (enter $10,000,000) . . . . . T

Excess (amount S minus amount T) (if negative, enter "0") ____ U

Gross Part I.3 tax for purposes of the small business deduction (Amount U x 0.00225) V

Enter this amount at line 415 of the T2 return

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2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Hydro One Inc.	86999 4731 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

T2 SCH 50 (09)

CORPORATE TAXPAYER / CONTRIBUABLE DES SOCIÉTÉS - EP12 VERSION 2009 V2.0

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86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc	86485 7635 RC0001	2009-12-31

On: 2009-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☐ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year	100	39,367,332	A
Taxable income for the year (DICs enter "0")*	110	15,269,581	B
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120		
Amount on line 400, 406, 410, or 425 of the T2 return, whichever is less*	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140		
Subtotal (add lines 120, 130 and 140)			C
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	15,269,581	
After-tax income (line 150 x general rate factor for the tax year ** 0.68)	190	10,383,315	D
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (add lines 200 and 210)			E
GRIP addition:			
Becoming a CCPC (line PP from Part 4)	220		
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230		
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240		
Subtotal (add lines 220, 230, and 240)	290		F
Subtotal (**add** lines A, D, E and F)		49,750,647	G
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year	310		
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.			
Subtotal (line 300 **minus** line 310)			H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)	490	49,750,647	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)	560		
GRIP at the end of the tax year (line 490 **minus** line 560) Enter this amount on line 160 on Schedule 55.	590	49,750,647	

* For lines 110, 120, 130 and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** **The general rate factor** for a tax year is the total of 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle those dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year		25,344,864	J1
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 406, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)			N1
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		25,344,864	O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (add lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 minus line T1) (if negative, enter "0") ▶ J1

Subtotal (line O1 minus line J1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to first previous tax year

(line V1 multiplied by the general rate factor for the tax year 0.68) 500

Second previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year 32,548,271 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 . . . . . .

Subtotal (add lines K2, L2, and M2) ▶ N2

Subtotal (line J2 minus line N2) (if negative, enter "0") 32,548,271 ▶ 32,548,271 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 . . . . . .

Subtotal (add lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 minus line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 minus line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to second previous tax year

(line V2 multiplied by the general rate factor for the tax year 0.68) 520

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year 24,316,024 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) 48,654 M3

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 . . . . . .

Subtotal (add lines K3, L3, and M3) 48,654 ▶ 48,654 N3

Subtotal (line J3 minus line N3) (if negative, enter "0") 24,267,370 ▶ 24,267,370 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R3

Aggregate investment income (line 440 of the T2 return) S3

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 . . . . . .

Subtotal (add lines Q3, R3, and S3) ▶ T3

Subtotal (line P3 minus line T3) (if negative, enter "0") ▶ U3

Subtotal (line O3 minus line U3) (if negative, enter "0") V3

GRIP adjustment for specified future tax consequences to third previous tax year

(line V3 multiplied by the general rate factor for the tax year 0.66) 540

Total GRIP adjustment for specified future tax consequences to previous tax years:

(add lines 500, 520, and 540) (if negative, enter "0") . . . . . W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post-amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for each predecessor and each subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year		AA
Eligible dividends paid by the corporation in its last tax year	BB	
Excessive eligible dividend designations made by the corporation in its last tax year	CC	
Subtotal (line BB **minus** line CC)	▶	DD
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)		EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		FF
The corporation's money on hand immediately before the end of its previous/last tax year		GG

Unused and unexpired losses at the end of the corporation's previous/last tax year

Non-capital losses		
Net capital losses		
Farm losses		
Restricted farm losses		
Limited partnership losses		
Subtotal	▶	HH
Subtotal (add lines FF, GG, and HH)		II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year	JJ	
Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year	KK	
All the corporation's reserves deducted in its previous/last tax year	LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year	MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year	NN	
Subtotal (add lines JJ, KK, LL, MM, and NN)	▶	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II minus line OO) (if negative, enter "0")		PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General Rate Factor for the Tax Year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to 4 decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	.....	=	0.6800	QC
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	.....	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 365	.....	=		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	.....	=		TT
General Rate Factor for the tax year (total of lines QC to TT)				.....		0.6800	UU

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

On: 2008-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the term's eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If no, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☐ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding up

9. Corporations that wound up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

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2009-12-31

Hydro One Brampton Networks Inc
88486 7635 RC0001

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	22,132,824 A
Taxable income for the year (DICs enter "0")*	110	25,344,864 B		
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140			
Subtotal (add lines 120, 130 and 140)		▶	C	
Income taxable at the general corporate rate (line B minus line C) (if negative enter "0")	150	25,344,864		
After-tax income (line 150 x general rate factor for the tax year **) 0.69			190	17,234,508 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 112 received in the tax year	210			
Subtotal (add lines 200 and 210)		▶		E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (add lines 220, 230, and 240)		▶	290	F
Subtotal (add lines A, D, E, and F)				39,367,332 G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310. Subtotal (line 300 minus line 310)		▶		H
GRIP before adjustment for specified future tax consequences (line G minus line H) (amount can be negative)			490	39,367,332
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 minus line 560)			590	39,367,332

Enter this amount on line 160 on Schedule 55.

* For lines 110, 120, 130 and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The general rate factor for a tax year is the total of 0.66 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year		32,548,271 J1		
Enter the following amounts before specified future tax consequences from the current tax year:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1			
Aggregate investment income (line 440 of the T2 return)	M1			
Subtotal (add lines K1, L1, and M1)		▶	N1	
Subtotal (line J1 minus line N1) (if negative, enter "0")		32,548,271 ▶		32,548,271 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (add lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 minus line T1) (if negative, enter "0") ▶ U1

Subtotal (line O1 minus line U1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to first previous tax year

(line V1 multiplied by the general rate factor for the tax year 0.68) 500

Second previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 24,316,024 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) 48,654 M2

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 . . . . . .

Subtotal (add lines K2, L2, and M2) 48,654 ▶ 48,654 N2

Subtotal (line J2 minus line N2) (if negative, enter "0") 24,267,370 ▶ 24,267,370 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 . . . . . .

Subtotal (add lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 minus line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 minus line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to second previous tax year

(line V2 multiplied by the general rate factor for the tax year 0.68) 520

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) M3

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 . . . . . .

Subtotal (add lines K3, L3, and M3) ▶ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") ▶ O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R3

Aggregate investment income (line 440 of the T2 return) S3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . .

Subtotal (**add lines** Q3, R3, and S3) ▶ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ▶ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") V3

GRIP adjustment for specified future tax consequences to third previous tax year

(line V3 **multiplied by** the general rate factor for the tax year 68 %) 540

Total GRIP adjustment for specified future tax consequences to previous tax years:
(add lines 500, 520, and 540) (if negative, enter "0") . . . . . W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it received the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year			AA
Eligible dividends paid by the corporation in its last tax year	RR		
Excessive eligible dividend designations made by the corporation in its last tax year	CC		
Subtotal (line BB **minus** line CC)		▶	DD
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)			EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC ☐ Post-amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year ..... FF

The corporation's money on hand immediately before the end of its previous/last tax year ..... GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses		
Net capital losses		
Farm losses		
Restricted farm losses		
Limited partnership losses		
Subtotal	▶	HH

Subtotal (**add** lines FF, GG, and HH) II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year ..... JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year ..... KK

All the corporation's reserves deducted in its previous/last tax year LL

The corporation's capital dividend account immediately before the end of its previous/last tax year ..... MM

The corporation's low-rate income pool immediately before the end of its previous/last tax year ..... NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ▶ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") ..... PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General Rate Factor for the Tax Year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to 4 decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	366 / 366	. . . . .	=	0.6800	QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 366	. . . . .	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 366	. . . . .	=		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 366	. . . . .	=		TT
General Rate Factor for the tax year (total of lines QQ to TT)				. . . . .		0.5800	UU

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2009-12-31

Hydro One Brampton Networks Inc
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

On: 2007-12-31

- If you are a Canadian controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 — 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	A
Taxable income for the year (DICs enter "0")*	110	32,548,271 B		
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140			
Subtotal (add lines 120, 130 and 140)		▶	C	
Income taxable at the general corporate rate (line B minus line C) (if negative enter "0")	150	32,548,271		
After-tax income (line 150 x general rate factor for the tax year ** 0.68)			190	22,132,824 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (add lines 200 and 210)		▶		E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (add lines 220, 230, and 240)		▶	290	F
Subtotal (add lines A, D, E, and F)			22,132,824	G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.				
Subtotal (line 300 minus line 310)		▶		H
GRIP before adjustment for specified future tax consequences (line G minus line H) (amount can be negative)			490	22,132,824
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 minus line 560) Enter this amount on line 160 on Schedule 55.			590	22,132,824

* For lines 110, 120, 130 and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is the total of 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year	24,329,172 J1		
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	48,654 M1		
Subtotal (add lines K1, L1, and M1)	48,654 ▶	48,654 N1	
Subtotal (line J1 minus line N1) (if negative, enter "0")	24,280,518 ▶		24,280,518 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (**add** lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ▶ J1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.68) 500

Second previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return) **multiplied by** 100/7 . . . . .

Subtotal (**add** lines K2, L2, and M2) ▶ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") ▶ O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Accelerated tax reduction (line 637 of T2 return) **multiplied by** 100/7 . . . . .

Subtotal (**add** lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.68) 520

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2004-12-31

Taxable income before specified future tax consequences from the current tax year J3

Enter the following amounts before specified future tax consequences from the current tax year.

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) M3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . .

Subtotal (**add** lines K3, L3, and M3) ▶ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") ▶ O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R3

Aggregate investment income (line 440 of the T2 return) S3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . .

Subtotal (add lines Q3, R3, and S3) ▶ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0"); ▶ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0"); V3

GRIP adjustment for specified future tax consequences to third previous tax year

(line V3 **multiplied by** the general rate factor for the tax year 08) 540

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post-amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year		AA
Eligible dividends paid by the corporation in its last tax year	BB	
Excessive eligible dividend designations made by the corporation in its last tax year	CC	
Subtotal (line BB **minus** line CC)	▶	DD
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)		EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		FF
The corporation's money on hand immediately before the end of its previous/last tax year		GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:		
Non-capital losses		
Net capital losses		
Farm losses		
Restricted farm losses		
Limited partnership losses		
Subtotal	▶	HH
Subtotal (add lines FF, GG, and HH)		II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ
Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK
All the corporation's reserves deducted in its previous/last tax year		LL
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN
Subtotal (add lines JJ, KK, LL, MM, and NN)	▶	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")		PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General Rate Factor for the Tax Year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to 4 decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	.....	=	0.6800	QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	.....	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 365	.....	=		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	.....	=		TT
General Rate Factor for the tax year (total of lines QQ to TT)				.....		0.6800	UU

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2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

On: 2006-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your T2 *Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . [X] Yes [ ] No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 . . . . .
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . [X] Yes [ ] No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . [ ] Yes [ ] No
5. Corporations that become a CCPC or a DIC . . . . . [ ] Yes [X] No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . [ ] Yes [X] No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . [ ] Yes [ ] No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . [ ] Yes [ ] No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . [ ] Yes [X] No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxaton year? . . . . . [ ] Yes [ ] No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP addition for 2006 (the greater of amount QQ from Part 9 "GRIP addition for 2006" or "0")	050		
GRIP at the end of the previous tax year	100		A
Taxable income for the year (DICs enter "0")*	110		B
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130		
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140	48,554	
Subtotal (add lines 120, 130 and 140)		48,554 ▶	48,654 C
Income taxable at the general corporate rate (line B minus line C) (if negative enter "0")	150		
After-tax income (line 150 x general rate factor** for the tax year** 0.68)			190 D
Eligible dividends received in the tax year	200		
Dividends deductible under section 113 received in the tax year	210		
Subtotal (add lines 200 and 210)		▶	F
GRIP addition:			
Becoming a CCPC (line PP from Part 4)	220		
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230		
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240		
Subtotal (add lines 220, 230, and 240)		▶	290 F
Subtotal (add lines A, D, E, and F)			G
Eligible dividends paid in the previous tax year	300		
Excessive eligible dividend designations made in the previous tax year	310		
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310			
Subtotal (line 300 minus line 310)		▶	H
GRIP before adjustment for specified future tax consequences (line G minus line H) (amount can be negative)			490
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560
GRIP at the end of the tax year (line 490 minus line 560)			590

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130 and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The general rate factor for a tax year is the total of 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year		J1
Enter the following amounts before specified future tax consequences from the current tax year:		
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1	
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1	
Aggregate investment income (line 440 of the T2 return)	M1	
Subtotal (add lines K1, L1, and M1)	▶	N1
Subtotal (line J1 minus line N1) (if negative, enter "0")	▶	O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (add lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 minus line T1) (if negative, enter "0") ▶ U1

Subtotal (line O1 minus line J1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to first previous tax year

(line V1 multiplied by the general rate factor for the tax year 0.68) 500

Second previous tax year 2004-12-31

Taxable income before specified future tax consecuences from the current tax year J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 .....

Subtotal (add lines K2, L2, and M2) ▶ N2

Subtotal (line J2 minus line N2) (if negative, enter "0") ▶ O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) ... Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Accelerated tax reduction (line 637 of T2 return) multiplied by 100/7 .....

Subtotal (add lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 minus line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 minus line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to second previous tax year

(line V2 multiplied by the general rate factor for the tax year 0.68) 520

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2003-12-31

Taxable income before specified future tax consequences from the current tax year J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less L3

Aggregate investment income (line 440 of the T2 return) M3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . .

Subtotal (**add** lines K3, L3, and M3) ▶ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") ▶ O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R3

Aggregate investment income (line 440 of the T2 return) S3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . .

Subtotal (**add** lines Q3, R3, and S3) ▶ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ▶ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") V3

GRIP adjustment for specified future tax consequences to third previous tax year

(line V3 **multiplied** by the general rate factor for the tax year 68) 540

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . W

Enter amount W on line 380.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nh. 1 Post amalgamation . . . ☐ Post wind up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year		AA
Eligible dividends paid by the corporation in its last tax year	BB	
Excessive eligible dividend designations made by the corporation in its last tax year	CC	
Subtotal (line BB **minus** line CC) ▶		JJ
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)		FF

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		FF
The corporation's money on hand immediately before the end of its previous/last tax year		GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses		
Net capital losses		
Farm losses		
Restricted farm losses		
Limited partnership losses		
Subtotal	▶	HH
Subtotal (**add** lines FF, GG, and HH)		II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ
Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK
All the corporation's reserves deducted in its previous/last tax year		LL
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN
Subtotal (**add** lines JJ, KK, LL, MM, and NN)	▶	OO
GRIP addition post amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")		PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General Rate Factor for the Tax Year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to 4 decimal places.

0.68	×	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	. . . . .	=	0.6800	QQ
0.69	×	number of days in the tax year in 2010 / number of days in the tax year	/ 365	. . . . .	=		RR
0.7	×	number of days in the tax year in 2011 / number of days in the tax year	/ 365	. . . . .	=		SS
0.72	×	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	. . . . .	=		TT
General Rate Factor for the tax year (total of lines QQ to TT)				. . . . .		0.6800	UU

Part – GRIP addition for 2006

Use this part to calculate the GRIP balance for a corporation that was a CCPC or would have been but for an election under subsection 89(11), throughout its tax year that includes January 1, 2006.

	Tax years ending in				
	2001	2002	2003	2004	2005
1. Taxable income for the year*					
2. Income for manufacturing and processing profits deduction* (lesser of amount V and Y in Part 9 of Schedule 27)				NIL	NIL
3. Income for manufacturing and processing profits deduction – electrical energy, steam* (amount QQ in Part 13 of Schedule 27)				NIL	NIL
4. Taxable resource income* (line 435 of the T2 return)					
5. Income for the credit union deduction* (amount E in Part 3 of Schedule 17)					
6. Income for the small business deduction* (amount on line 400, 405, 410, and 425 of the T2 return, whichever is less)					
7. Aggregate investment income* (line 440 of the T2 return)					
8. Income for the accelerated tax reduction* (line 627 of the T2 return multiplied by 100/7)					NIL
9. **Subtotal** (add rows 2 through 8)					
10. Full rate taxable income before specified future tax consequences (row 1 **minus** row 9) (if negative, enter "0")					
11. **Multiply** row 10 by 63.00 %					
12. Dividends deductible under subsection 112(1) received from connected corporations, that are reasonably considered, to have been paid out of full rate taxable income in respect of the payer corporation	941	942	943	944	945
13. Subtotal (**add** row 11 and row 12)					
14. Total taxable dividends paid by the corporation (dividends other than capital dividends under subsection 83(2) – from Schedule 3, the greater of the following amounts: i) line 460; and ii) line 500 **minus** line 510)					
15. GRIP addition (row 13 **minus** row 14)	951	952	953	954	955

GRIP addition for 2006 (add lines 951, 952, 953, 954, and 955) . . . . . QQ

Enter the greater of amount QQ or "0" on line 050.

* **Note:** For rows 1 to 8, all income amounts are before considering the specified future tax consequences for that tax year.

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Hydro One Brampton Networks Inc.
86486 7635 RC0001

Schedule of Instalment Remittances

Name of corporation contact: Tony Paul
Telephone number: (905) 840-6300

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments - Federal	2,891,820
	Instalments - Ontario	4,640,454

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 7,532,274 A

Total instalments credited to the taxation year per T9 7,532,274 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:	1800040	2009-12-31	1,943,414	2010-03-31	2009 Ontario Refund
To:	180040	2010-12-31			
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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2009-12-31

Hydro One Brampton Networks Inc
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- References to subsections and paragraphs are from the federal *Income Tax Act*.
- This schedule is a worksheet only and does not have to be filed with your T2 *Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic income tax

Ontario taxable income * ..... 15,269,581 A

Ontario basic income tax: amount A multiplied by 14 % ..... 2,137,741 B

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount B on line 270 of Schedule 5, *Tax Calculation Supplementary - Corporations*. Otherwise, enter it on line 760 on page 8 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return) 15,272,231 1

Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) 2

Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) ..... x 500,000 / 500,000 = 3

line 4 on page 4 of the T2 return

Enter the least of amounts 1, 2, and 3 C

Ontario domestic factor: Ontario taxable income * / taxable income earned in all provinces and territories ** 15,269,581.00 / 15,269,581 = ... 1.00000 D

Ontario small business income (amount C multiplied by amount D) ..... E

OSBD rate for the year ..... 8.5 %

Ontario small business deduction (amount E multiplied by OSBD rate for the year) ..... F

Enter amount F on line 402 of Schedule 5.

* Enter amount A from Part 1.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 3 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD, and its adjusted taxable income, plus the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Adjusted taxable income *	15,269,581 G		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	H		
Aggregate adjusted taxable income (amount G plus amount H)	15,269,581	▶ 15,269,581	I
Deduct:			
Ontario business limit		500,000	
Subtotal (amount I **minus** Ontario business limit) (if negative, enter "0" on this line and on line M)		14,769,581	J
Small business surtax rate for the year	4.25 %		
Multiply: Line J x small business surtax rate for the year =		627,707	K
Amount K × Ontario small business income (amount E in Part 2) 500,000 / 500,000 =			L
Ontario surtax re Ontario small business deduction: lesser of amount L and OSBD (amount F in Part 2)			M

Enter amount M on line 212 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year plus the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Amount C in Part 2					N
Surtax payable (amount M in Part 3) / Ontario domestic factor (amount D in Part 2)	x	8.5 %	0.08500	=	O
Ontario adjusted small business income (amount N **minus** amount O) (if negative, enter "0")					P

Enter amount P on line R in Part 5 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D in Part 3 of Schedule 17		Q
Deduct:		
Ontario adjusted **small business** income (amount P in Part 4)		R
Subtotal (amount Q **minus** amount R) (if negative, enter "0")		S
OSBD rate for the year	8.5 %	
Amount S **multiplied** by the OSBD rate for the year		T
Ontario domestic factor (amount D in Part 2)	1.00000	U
Ontario credit union tax reduction (amount T **multiplied** by amount U)		V

Enter amount V on line 410 on Schedule 5.

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SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or claiming the Ontario transitional tax credit.
- Unless otherwise noted, references to parts, subsections, paragraphs, subparagraphs, and clauses are from the federal *Income Tax Act*.
- For more information on how to complete this schedule, see Guide T4012, *T2 Corporation – Income Tax Guide*.
- File this schedule with the T2 *Corporation Income Tax Return*.
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal *Income Tax Act*;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal *Income Tax Act*;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part III of the *Corporations Tax Act* (Ontario) for that year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of the *Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the year; or
  - the corporation has an unused transitional tax credit balance from previous years.
- Transition time is defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario) as:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on the last day of 2008; or
  - the beginning of the corporation's tax year that includes the beginning of 2009 in any other case.
- An eligible amalgamation refers to an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An eligible post-2008 windup means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year during which it received the assets of the subsidiary ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An eligible pre-2009 windup means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year during which it received the assets of the subsidiary ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year during which it received the assets of the subsidiary ended after December 31, 2008.
- The completion time of a windup is the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A specified pre-2009 transfer under section 52 of the *Taxation Act, 2007* (Ontario) is a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, exclude the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	249,681,269
Charitable donations not yet deducted from income (from line 260 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 680 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 690 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	26,328,476
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (from line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (s), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act at the beginning of the tax year	160	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162	
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164	
Federal balance before election (total of lines 110 to 164)		276,009,745 A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	
Total federal balance (amount A minus line 170)	180	276,009,745

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.
Note 2: Enter "0" if control of the corporation was acquired at transition time.
Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.
Note 4: Do not include non-capital losses that arose before control of the corporation was last acquired.

Part 2 – Total Ontario balance

Complete this part if:

– the tax year includes January 1, 2009; or

– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, exclude the amounts under the additional rules in subsection 46(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	249,681,269
Charitable donations (amount I from Ontario Schedule 2, *Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	26,328,475
Ontario SR&ED expenditure pool (line 460 from Ontario CT23 *Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (see Note 2 and Note 4) (from line 709 of Ontario *Corporations Tax Return* CT8 or *CT23 Corporations Tax and Annual Return*)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %)	236	13,148

Amounts included in the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m) (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(ii) or 44(1)(e)(ii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264) Enter amount on line 340 in Part 3.	290	276,022,893

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include non-capital losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:

– have been earned and are available without restriction to the corporation;

– are attributable to qualifying Ontario SR&ED expenditures;

– have not been deducted under subsection 127(5) or (6) of the federal Act; and

– do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor (relevant OAF) as calculated in Part 11.

Part 3 – Total federal balance and total Ontario balance at the end of the year

Total federal balance:

Total federal balance (amount from line 180 in Part 1) or total federal balance at the end of the previous tax year (line 330)	300	276,009,745		
Add:				
Amount from eligible amalgamation*	310			
Amount from eligible post-2008 windup*	315			
Amount from eligible pre-2009 windup*	320			
Amount from specified pre-2009 transfers*	325			
Total federal balance at the end of the year		276,009,745 ▶	330	276,009,745

Total Ontario balance:

Total Ontario balance (from line 280 in Part 2) or total Ontario balance at the end of the previous tax year (amount from line 370)	340	276,022,893		
Add:				
Amount from eligible amalgamation*	350			
Amount from eligible post-2008 windup*	355			
Amount from eligible pre-2009 windup*	360			
Amount from specified pre-2009 transfers*	365			
Total Ontario balance at the end of the year		276,022,893 ▶	370	276,022,893
Transitional balance at the end of the year (line 330 minus line 370)			390	-13,148

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation*.

Part 4 – Election to reduce federal SR&ED expenditure pool

This election may be made if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? 400 1 Yes ☐ 2 No ☒

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1)				B
Deduct:				
Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2)		1		
Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2)		2		
	Subtotal (amount 1 **plus** amount 2) ▶			C
	Subtotal (amount B **minus** amount C) (if negative, enter "0")			D
Federal balance before election (amount A from Part 1)				
Deduct:				
Total Ontario balance (amount from line 280 in Part 2)				
	Subtotal (if negative, enter "0")			E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period of a corporation starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:

- the calendar years after the time immediately before the corporation's first tax year ending after December 31, 2008; or
- December 31, 2013.

Number of days in the corporation's reference period* (do not include February 29, 2008, and February 29, 2012) . . 410 1,625

* The number of days in the corporation's reference period is 1825 unless:

- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or
- the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

- the end of the corporation's reference period; or
- the early termination as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) 420 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:

- the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or
- the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a permanent establishment in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debt.
Note: The Ontario Allocation Factor (OAF), calculated in Part 6, must be at least 30% or the amount on line 380 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 6 cannot be more than $1,000.

If you ticked one of the above boxes:

– enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 435

– enter the number of days remaining in the corporation's reference period that are on or after the first day of the tax year (do not include February 29, 2008, or February 29, 2012) 443

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario", enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple", complete the following calculation and enter the result on line F:

$$\frac{\text{Ontario taxable income*}}{\text{Taxable income**}} = \text{F}$$

Ontario allocation factor (OAF) . . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary - Corporations*. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3				G
Amount G x	14 %			H
Amount H x OAF (from line F in Part 6)	1.00000			I
Number of days from line 440 in Part 5 (if applicable) or number of days in the corporation's reference period that are in the tax year (do not include February 29, 2008, or February 29, 2012)	365	=	0.20000	J
Number of days in the corporation's reference period from line 410 in Part 5	1,325			

Transitional tax debits before tax on elected reduced SR&ED pool (amount I multiplied by amount J) . . . . . K

Post-2008 SR&ED balance at the end of the year (amount HH from Part 12) 460

Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14) 470

Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470) L

Total transitional tax debits (amount K plus amount L) . . . . . M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5 . . . . . 2,137,741 N

Deduct:

Ontario resource tax credit (from line 404 of Schedule 5)			
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)			
Ontario foreign tax credit (from line 408 of Schedule 5)			
Ontario credit union tax reduction (from line 410 of Schedule 5)			
	Subtotal	▶	O
	Subtotal (amount N minus amount O)	2,137,741	P
Number of days in the amortization period that are in the tax year (from line 420 in Part 5)	365 =	1.00000	Q
Number of days in the tax year (do not include February 29, 2008, or February 29, 2012)	365		

Ontario tax payable for purposes of the current year transitional credit (amount P multiplied by amount Q) 510 2,137,741

Amount from line 390 in Part 3 (enter as a positive amount)		13,148	R
Amount R x	14 %	1,841	S
Amount S x OAF (from line F in Part 6)		1,841	T
Number of days from line 440 (if applicable) or line 420 in Part 6	365 =	0.20000	U
Number of days in the corporation's reference period on line 410 in Part 5	1,825		

Current-year transitional tax credit (amount T multiplied by amount J) 520 368

Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0") 530 2,137,373

Transitional tax credit:

Lesser of amounts on line 510 and 520 . . . . . 368 V

Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530 . . . . . W

Transitional tax credit (amount V **plus** amount W) . . . . . 368 X

Enter amount X on line 414 of Schedule 5.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)* 1

Add:

Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2003 windup* 550 2

Unused transitional tax credit available (amount 1 plus amount 2) ..... Y

Add:

Current-year transitional tax credit (amount from line 520 in Part 8) ..... 368 Z

Subtotal (amount Y **plus** amount Z) 368 3

Deduct:

Transitional tax credit applied (amount X from Part 8) ..... 368 AA

Unused transitional tax credit (available for subsequent years) (amount 3 **minus** amount AA) 580

* Enter "0" if this is the first tax year ending after 2008.

Complete Parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a) 610

Capital SR&ED expenditures in the year under paragraph 37(1)(b) 614

Repayment of assistance under paragraph 37(1)(c) 618

Investment tax credit recaptured under subsections 127(27), (28), and (31) in the previous tax year 624

Subtotal (total of lines 610 to 624) ..... BB

Deduct:

Assistance under paragraph 37(1)(d) 638

Investment tax credits deducted under paragraph 37(1)(e) 644

Subtotal (line 638 plus line 644) CC

Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC) 650

If the amount on line 650 is positive, enter it on line II in Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

- the corporation's OAF for the tax year that includes its transition time (from line F in Part 6) .....
- the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) .....
- the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008 .....

Relevant OAF ..... 660 %

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

- the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;
2) a corporation that wound up into the particular corporation under subsection 88(1); or
3) a designated corporation in relation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . . DD

SR&ED expenditure amount deducted in the year under subsection 37(1) 670

Deduct:

Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) 675

Subtotal (line 670 **minus** line 675) (if negative, enter "0") ▶ EE

Subtotal (amount DD **plus** amount EE) FF

Amount FF x 14 % GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 680 from Part 11) . . . . . HH

Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) II

Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 700

Subtotal line (II **plus** line 700) JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 705

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) 710

Deduct:

Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year 715

Subtotal (line 710 **minus** line 715) 720

Line 720 = ▶ KK

Relevant OAF (from line 660 in Part 11) x 14 %

Subtotal (line 705 **minus** amount KK) ▶ 730

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") LL

Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1* . . . . . 735 MM

Relevant OAF* (from line 660) **multiplied** by amount MM NN

Amount NN x 14 % ▶ CO

Federal SR&ED transitional balance transferred on an eligible amalgamation, an eligible post-2008 wind-up, or an eligible pre-2009 wind-up (total of lines 310, 315, and 320 from Part 3) 740

Subtotal (amount OO **plus** line 740) PP

Deduct:

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) 750

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . . QQ

Enter amount QQ on line 470 in Part 7.

* For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

HOBNI 209:209
2010-05-13 09:27

2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

SCHEDULE 515

Canada Revenue Agency / Agence du revenu du Canada

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- To complete this schedule, you have to complete Schedule 33, *Part I 3 Tax on Large Corporations*. File completed copies of both schedules with the T2 *Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	287,609,414		
Add:				
Accumulated other comprehensive income at the end of the year	105			
	Subtotal	287,609,414 ▶	287,609,414	A
Deduct:				
Amount B from Part 1 of Schedule 33	110	14,106,618		
Amount on line 490 from Part 2 of Schedule 33	115			
	Subtotal	14,106,618 ▶	14,106,618	B
Taxable capital (amount A minus amount B) (if negative, enter "0")		120	273,502,796	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? 190 1 Yes ☐ 2 No ☐

If you answered no to the question at line 190, complete line 220. If you answered yes to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction: Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33)	200		x 15,000,000 $	– Capital deduction	220
Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year *	210				

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516)	300	441,353	=	Capital deduction	305 441,353
Ontario allocation factor (OAF) (amount I in Part 3)					

Canada

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1, or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies	320	273,502,796	
Deduct:			
Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2)		441,353	B
Net amount (line 320 minus amount B) (if negative, enter "0")		273,061,443	C

Amount C 273,061,443 × (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) 365 / 365 × 0.00225 = 614,388 D

Amount C 273,061,443 × (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) 365 / 365 × 0.00100 = E

Subtotal (amount D plus amount E)		614,388	F
Amount F 614,388 × OAF (amount on line I) 1.00000 =		614,388	G
Amount G 614,388 × Number of days in the tax year * 366 / 366 =		614,388	H
Deduct:			
Capital tax credit for manufacturers (enter amount J from Part 4)	350		
Ontario capital tax payable (amount H minus line 350) (if negative, enter "0")	400	614,388	

Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations*.

* Enter either 366 if there are at least 61 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

Ontario taxable income ** / Taxable income *** =

Ontario allocation factor	1.00000	I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line 2 of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

Ontario manufacturing labour cost* 405 / Total Ontario labour cost** 410 × 100 = 420 %

If the percentage on line 420 is 20% or less, enter "0" on line J.

If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.

If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) – 20% / 30% × 30.000 % × 614,388 Amount H from Part 3 =

Capital tax credit for manufacturers		J

Enter amount J on line 350 in Part 3.

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)

** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 524

ONTARIO SPECIALTY TYPES

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- Use this schedule to identify the specialty type of a corporation carrying on business in the province of Ontario through a permanent establishment if:
  - its tax year includes January 1, 2009;
  - the tax year is the first year after incorporation or an amalgamation; or
  - there is a change to the specialty type.
- If none of the listed specialty types applies, tick box 99 "Other."
- Unless otherwise noted, references to sections, subsections, and clauses are from the *Taxation Act, 2007* (Ontario).

Specialty types

100 Identify the specialty type that applies to your corporation:

- [ ] 01 Family farm corporation – See subsection 64(3).
- [ ] 02 Family fishing corporation – See subsection 64(3).
- [ ] 03 Mortgage investment corporation – See subsection 130.1(6) of the federal *Income Tax Act*.
- [ ] 04 Credit union – See subsection 137(6) of the federal Act.
- [ ] 06 Bank – See subsection 248(1) of the federal Act.
- [ ] 08 Financial institution prescribed by regulation only – See clause 66(2)(f).
- [ ] 09 Registered securities dealer – See subsection 248(1) of the federal Act.
- [ ] 10 Farm feeder finance co-operative corporation
- [ ] 11 Insurance corporation – See subsection 248(1) of the federal Act.
- [ ] 12 Mutual insurance – See subsection 27(2) of the *Taxation Act, 2007* (Ontario) and paragraph 149(1)(m) of the federal Act.
- [ ] 13 Specialty mutual insurance
- [ ] 14 Mutual fund corporation – See subsection 131(8) of the federal Act.
- [ ] 15 Bare trustee corporation
- [ ] 16 Professional corporation (incorporated professional only) – See subsection 248(1) of the federal Act.
- [ ] 17 Limited liability corporation
- [ ] 18 Generator of electrical energy for sale, or producer of steam for use in the generation of electrical energy for sale – See subsection 33(7).
- [X] 19 Hydro successor, municipal electrical utility, or subsidiary of either – See subsection 91.1(1) and section 88 of the *Electricity Act, 1998* (Ontario).
- [ ] 20 Producer and seller of steam for uses other than for the generation of electricity – See subsection 33(7).
- [ ] 21 Mining corporation
- [ ] 22 Non-resident corporation
- [ ] 99 Other (if none of the previous descriptions apply)

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2009-12-31

Hydro One Brampton Networks Inc.
86486 7635 RC0001

SCHEDULE 546

Canada Revenue Agency / Agence du revenu du Canada

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the *Business Corporations Act* (BCA) or *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the Ontario *Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to record change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up to date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Hydro One Brampton Networks Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	110 Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	120 Ontario Corporation No.
Ontario	2000-05-01	1414330

Part 2 – Head or registered office address (P.O. box not acceptable)

200 Care of (if applicable)

210 Street number	220 Street name	230 Suite number
175	Sandalwood Parkway West	

240 Additional address information

250 Municipality (e.g., city, town)	260 Province/state	270 Country	280 Postal/zip code
Brampton	ON	CA	L7A 1E8

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS with respect to names, addresses for service, and the date elected/appointed and date ceased of the directors and five most senior officers, or the corporation's mailing address or language of preference? Obtain a Corporation Profile Report to review the information shown for the corporation on the public record maintained by the MGS. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter 1 in this box and then go to "Part 4 – Certification."
If there are changes, enter 2 in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 PAUL (Last name) 451 TONY (First name)

454 (Middle name(s))

460 3 Please enter one of the following numbers in this box for the above-named person: enter 1 for director, 2 for officer, or 3 for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter 1 or 2.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Canada

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 [ ] Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows.

510 Care of (if applicable)

520 Street number | 530 Street name | 540 Suite number

550 Additional address information

560 Municipality (e.g., city, town) | 570 Province/state | 580 Country | 590 Postal/zip code

Part 6 – Language of preference

600 [1] Indicate your language preference by entering 1 for English or 2 for French. This is the language of preference recorded on the MGS public record for communication with the corporation. This may be different from line 9R0 on the T2 return.

86486 7635 RC000

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer the institution, the term of the WP, and the name/discipline of the CCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information: TONY PAUL

120 Telephone number including area code: (905) 457-5505

Is the claim filed for a CETC earned through a partnership? * ..... 150 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? 160

Enter the percentage of the partnership's CETC allocated to the corporation ..... 170 %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? ..... 200 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? ..... 210 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * 300 15,821,699

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \left(\frac{\text{amount on line 300 minus } \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount ..... 310 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \left(\frac{\text{amount on line 300 minus } \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount ..... 312 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation as designated by the corporations.

	A Name of university, college or other eligible educational institution 400	B Name of qualifying co-operative education program 405
1.	Cambrian College	Powerline
2.	Cambrian College	Powerline
3.	Cambrian College	Powerline
4.	Cambrian College	Powerline
5.	Cambrian College	Power line
6.	UT - Mississauga	MMPA

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	[redacted]	2009-09-01	2009-12-06
2.	[redacted]	2009-05-19	2009-08-28
3.	[redacted]	2009-05-19	2009-08-28
4.	[redacted]	2009-05-19	2009-08-28
5.	[redacted]	2009-05-19	2009-08-28
6.	[redacted]	2009-01-26	2009-04-30

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	G Eligible amount (eligible expenditures multiplied by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462
1.		10,428	2,607	3,000
2.		10,315	2,579	3,000
3.		10,800	2,700	3,000
4.		10,258	2,565	3,000
5.		9,930	2,483	3,000
6.	6,831	3,984	1,679	1,737

	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1	2,607		2,607
2	2,579		2,579
3	2,700		2,700
4	2,565		2,565
5.	2,483		2,483
6.	1,679		1,679

Ontario co-operative education tax credit (total of amounts in column K) 500 — 14,613 L

or, if the corporation answered yes at line 160 in Part 1, determine the partner's share of amount I :

Amount L _____ x percentage on line 170 in Part 1 _____ % = ... _____ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + $3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009,
and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to F and I and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Brampton Networks Inc.	86486 7635 RC0001	2009-12-31

- If you are a corporation, use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 30%) of the eligible expenditures incurred by a corporation in respect of a qualifying apprenticeship. The maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program.
- **An expenditure is not eligible for an ATTC if the same expenditure was used, or will be used, to claim a co-operative education tax credit or if it is greater than an amount that would be paid to an arm's length apprentice.**
- An apprenticeship must meet all of the following conditions to be a qualifying apprenticeship:
  - The apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario).
  - The corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Ensure that you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with the *T2 Corporation Income Tax Return*.
- Submit a completed copy of Schedule 552 when you file your T2 return.

Part 1 – Corporate information

110 Name of person to contact for more information: TONY PAUL	120 Telephone number including area code: (905) 452-5505	
Is the claim filed for an ATTC earned through a partnership? *	150	1 Yes ☐ 2 No ☒
If yes to the question at line 150, what is the name of the partnership?	160	
Enter the percentage of the partnership's ATTC allocated to the corporation	170	%

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year?	200	1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)?	210	1 Yes ☐ 2 No ☒

If you answered no to question 1 or yes to question 2, then you are **not eligible** for the ATTC.

Part 3 – Calculation of the specified percentage

Corporation's salaries and wages paid in the previous tax year * 300 15,321,699

- If line 300 is $400,000 or less, enter 30% on line 310, after March 26, 2009 enter 40% on line 310a
- If line 300 is $600,000 or greater, enter 25% on line 310, after March 26, 2009 enter 35% on line 310a
- If line 300 is over $400,000 and less than $600,000, enter the percentage on line 310 or 310a using the following formula:

Eligible percentage before March 27, 2009 = 30 % − [5 % × (amount at line 300 minus 400,000) / 200,000]

Eligible percentage before March 27, 2009 (enter at column K in Part 4) 310 25.000 %

Eligible percentage after March 26, 2009 = 45 % − [10 % × (amount at line 300 minus 400,000) / 200,000]

Eligible percentage after March 26, 2009 (enter at column K1 in Part 4) 310a 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Information on qualifying apprentice(s) and calculation of tax credit

Complete a separate entry for each apprentice that is a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a separate entry for each repayment and complete columns A to G and N and O with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425
1.	434a	Lineworker		D06548	2007-02-26
2.	434a	Lineworker		PD1787	2008-03-25
3.	434a	Lineworker		PA6226	2008-09-02
4.	434a	Lineworker		PA4072	2009-08-31
5.	434a	Lineworker		PA4124	2009-08-31
6.	434a	Lineworker		PA9032	2009-12-07
7.	434a	Lineworker		D19239	2008-03-25

	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435	H Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 4 below) 440	H1 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 4 below)	I Limit for the tax year (see note 5 below) 445	J Eligible expenditures before March 27, 2009 (see note 6 below) 450	K Specified percentage before March 27, 2009 (from line 310 in Part 3)
1.	2009-01-01	2009-12-31	85	280	8,835	7,058	25.000 %
2.	2009-01-01	2009-12-31	85	280	8,835	13,347	25.000 %
3.	2009-01-01	2009-12-31	85	280	8,835	12,542	25.000 %
4.	2009-08-31	2009-12-31		123	3,370		25.000 %
5.	2009-08-31	2009-12-31		123	3,370		25.000 %
6.	2009-12-07	2009-12-31		25	685		25.000 %
7.	2009-01-01	2009-09-25	85	183	6,178	19,658	25.000 %

	J1 Eligible expenditures after March 26, 2009 (see note 6 below)	K1 Specified percentage after March 26, 2009 (from line 310a in Part 3)	L Product of column J multiplied by column K 460	M ATTC on eligible expenditures (lesser of columns I and L) 470	N ATTC on repayment of government assistance (see note 7 below) 480	O ATTC for each apprentice (column M or column N, whichever applies) 490
1.	23,252	35.000 %	9,903	8,835		8,835
2.	43,968	35.000 %	18,726	8,835		8,835
3.	41,313	35.000 %	17,596	8,835		8,835
4.	14,887	35.000 %	5,210	3,370		3,370
5.	16,546	35.000 %	5,791	3,370		3,370
6.	2,568	35.000 %	899	685		685
7.	42,322	35.000 %	19,728	6,178		6,178

If insufficient space, attach additional schedule(s).

Ontario apprenticeship training tax credit (total of amounts in column O) 500 — 40,108 P

or, if the corporation answered yes at line 150 in Part 1, determine the partner's share of amount P:

Amount P _____ × percentage at line 170 in Part 1 _____ % = ... _____ Q

Enter amount P or Q, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line P or Q, whichever applies, on all the schedules and enter the total amount on line 454 of Schedule 5.

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Note 4: The days employed as an apprentice in the tax year must be within 36 months of the registration date provided in column E and cannot extend beyond the end date of employment as an apprentice for the tax year with the corporation entered in column G. When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.

Note 5: Limit for the tax year when days are before March 27, 2009, 5 000 * column H /365. Divide by 366 days when the tax year includes February 29. Limit for the tax year when days are after March 26, 2009, 10 000 * column H1 /365. Divide by 366 days when the tax year includes February 29.

Note 6: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 7: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.

ONTARIO CAPITAL TAX

Table 1: Ontario Capital Tax ('000s)

	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 test year
Taxable Capital		295,222	303,036	317,073	273,449	307,013	NA
Capital Tax Rate	0.300%	0.300%	0.225%	0.225%	0.225%	0.075%(1)	NA
Capital Tax		886	682	713	615	230	NA

Note 1: Ontario Capital Tax rate effective January 1, 2010 and is eliminated July 1, 2010. The 0.075% represents the weighted average.

PROPERTY TAX

Hydro One Brampton owns numerous properties in the City of Brampton. Property taxes are paid on a per property basis and are considered an uncontrollable expense. **Table 1** below shows Hydro One Brampton properties and their property assessment values for 2006 to 2011. For the 2011 test year, Hydro One Brampton estimated a 3.5% increase in property taxes, a conservative increase based on historical trends. Actual and estimated amounts for property taxes are shown in **Table 2.**

Table 1: Properties and Property Assessment Values for 2006 – 2011

Location.	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010	2011
175 Sandalwood Pky	14,702,000	14,702,000	14,702,000	13,609,250	**14,163,500**	**14,717,750**
25 Coventry Road	424,000	424,000	424,000	474,750	525,500	576,250
6 Easton Place	242,000	242,000	242,000	263,250	284,500	305,750
149 Hansen Road N.	166,000	166,000	166,000	171,500	177,000	182,500
18 Grassmear Cres	165,000	165,000	165,000	167,500	**170,000**	**172,500**
398 Orenda Road	234,000	234,000	234,000	248,000	262,000	276,000
9066 Dixie Road	421,000	421,000	421,000	455,500	490,000	524,500
125 Team Canada Drive	269,000	269,000	269,000	285,750	**302,500**	**319,250**
44 Church Street West	58,000	58,000	58,000	61,500	65,000	68,500
8 Elizabeth St N.	179,000	179,000	179,000	187,250	195,500	203,750
8057 Mc Laughlin Road S.	163,000	163,000	163,000	169,750		
230 Steeles Ave W	147,000	147,000	147,000	152,250	157,500	162,750
212 Rutherford Road S.	177,000	177,000	177,000	185,500	194,000	202,500
67 Eastern Ave.	65,000	65,000	65,000	68,250	71,500	74,750
Kennedy Road S / 273-2 Glidden Road	48,500	48,500	48,500	51,875	55,250	58,625
1100 Steeles W.	593,000	593,000	593,000	650,750	708,500	766,250
O Archdekin Drive	188,000	188,000	188,000	203,250	218,500	249,000
8686 McLaughlin Road S.						
TOTAL	**18,241,500**	**18,241,500**	**18,241,500**	**17,405,875**	18,040,750	18,860,625

Table 2: Actual and Estimated Amounts for Property Taxes

Location.	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge Year	2011 Test Year
175 Sandalwood Pkwy	396,529	405,981	415,356	372,726	381,299	390,069
25 Coventry Road	13,045	13,357	13,645	14,830	15,171	15,520
6 Easton Place	7,446	7,624	7,788	8,223	8,412	8,606
149 Hansen Road N.	5,107	5,230	5,342	5,357	5,480	5,606
18 Grassmear Cres	5,077	5,198	5,310	5,232	5,353	5,476
398 Orenda Road	7,199	7,372	7,531	7,747	7,925	8,107
9066 Dixie Road	12,953	13,263	13,549	14,229	14,556	14,891
125 Team Canada Drive	8,276	8,474	8,657	8,926	9,131	9,341
44 Church Street West	1,784	1,827	1,867	1,921	1,965	2,010
8 Elizabeth St N.	5,507	5,639	5,761	5,849	5,984	6,121
8057 Mc Laughlin Road S.	5,015	5,135	5,246	5,303	5,425	5,549
230 Steeles Ave W	4,523	4,631	4,731	4,756	4,865	4,977
212 Rutherford Road S.	5,446	5,576	5,696	5,795	5,928	6,064
67 Eastern Ave.	2,000	2,048	2,092	2,132	2,181	2,231
Kennedy Road S / 273-2 Glidden Road	1,492	1,528	1,561	1,620	1,658	1,696
1100 Steeles W.	18,042	18,681	19,084	20,328	20,795	21,274
O Archdekin Drive	4,049	4,146	4,235	4,444	4,547	4,651
8686 McLaughlin Road S.	0	0	0	0		
TOTAL	503,490	515,710	527,448	489,418	500,675	512,190

TAX CREDITS

Hydro One Brampton has no significant tax credits.

EXHIBIT 5

COST OF CAPITAL AND RATE OF RETURN

EXHIBIT 5 TAB 1

CAPITAL STRUCTURE

CAPITAL STRUCTURE SUMMARY

INTRODUCTION

The purpose of this evidence is to summarize the method and cost of financing Hydro One Brampton's capital requirements for the 2010 Bridge Year and 2011 Test Year.

Capital Structure/Capitalization:

Hydro One Brampton's 2006 OEB approved deemed capital structure was 55% debt with a return of 6.95% and 45% equity with a return of 9.00%. In the next two 2nd Generation IRM rate applications Hydro One Brampton's deemed structure was transitioned to 57.5%/42.5% debt/equity in 2007, and then to 60%/40% debt/equity in 2008.The existing rates of return on rate base continue to be based on the 2006 OEB Approved returns noted above.

Hydro One Brampton has prepared this rate application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006.

COST OF CAPITAL

The following section outlines Hydro One Brampton's assumptions with respect to long term debt, short term debt, and return on equity.

RETURN ON EQUITY:

Hydro One Brampton is requesting a return on equity ("ROE") for the 2011 Test year of 9.92%.

The ROE Formula Computation deriving the ROE used for the Revenue Requirement was as follows:

Table 1: Return on Equity Calculation

Return on Equity Calculation			
Initial ROE			9.75%
Canada Bond Yield Change Adjustment			
March 2010 Consensus Forecast 10 year Canada	4.10%		
Average Actual 10 to 30 year term spread March 2010	0.57%		
30 Year Canada Long Bond Forecast Yield		4.67%	
Less Initial 30 year Canada Yield		-4.25%	
Yield Change		0.42%	
Adjustment (50% of Change)			0.21%
Utility Bond Yield Change Adjustment			
Average Utility A Bond Spread March 2010		1.33%	
Less: Base Utility A Spread		-1.42%	
Yield Change		-0.09%	
Adjustment (50% of Change)			-0.04%
Return on Equity			9.92%

Hydro One Brampton computed the ROE based on the March 2010 Consensus Forecast and March 2010 Government of Canada and A-rated Canadian Utility index bond yields.

Hydro One Brampton understands that the OEB will be finalizing the ROE for 2011 rates based on January 2010 market interest rate information. Hydro One Brampton's use of an ROE of 9.92% is without prejudice to any revised ROE that may be adopted by the OEB in early 2011.

Cost of Debt: Long Term

Hydro One Brampton is requesting a return on Long Term Debt for the 2011 Test Year of 6.76% which is the weighted average long term debt for the 2011 Test Year. **Table 2** below calculates the debt rate:

Table 2: Long Term Debt and Weighted Average Debt Rate for 2011 Test Year

Description	Issue Date	Debenture	Debt Rate	Interest on Debt
Debt through parent company public debenture issue	2001	$ 143,000,000	6.95%	$ 9,938,500
New Debt to be issued through parent in 2010	2010	$ 10,000,000	5.71%	$ 571,000
New Debt to be issued through parent in 2011	2011	$ 47,000,000	6.41%	$ 3,012,700
Totals		**$ 200,000,000**	**6.76%**	**$ 13,522,200**

All debt held by Hydro One Brampton is held by its shareholder Hydro One Inc. through external debt issuances. In the Cost of Capital Report the OEB determined "that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.

Cost of Debt: Short Term

Hydro One Brampton is requesting a return on Short Term Debt for the 2011 Test Year of 2.07% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on March 7, 2009. Hydro One Brampton understands that the OEB will be finalizing the return on short term debt for 2011 rates based on January 2011 market interest rate information. Hydro One Brampton's use of a Return on Short Term Debt of 2.07% is without prejudice to any revised ROE that may be adopted by the OEB in early 2010.

NEW LONG-TERM DEBT ASSUMPTIONS

At the end of 2009 HOBNI had $143 million of long-term debt with Hydro One Inc. at an annual interest rate of 6.95%. HOBNI proposes to add $10 million of new long-term debt with Hydro One Inc. in 2010, and another $47 million in 2011. This new debt has an assumed 30 year term at an annual interest rate of 5.71% and 6.41% respectively.

Table 3: Interest Rate Assumption Used for the Bridge and Test Years

Interest rate assumptions *	2010	2011
HO1 5-Year Bond Rate (%)	3.56	4.26
HO1 10-Year Bond Rate (%)	4.68	5.38
HO1 30-Year Bond Rate (%)	5.71	6.41
90-Day Banker's Acceptance Rate (%)	0.84	2.49
Interest Capitalized Brampton (%)	4.91	5.61

**** Rates used for 2011 business planning purposes***

Hydro One Inc. bond rates for 2010 were prepared based on the November 2009 edition of Consensus Forecasts; Hydro One Inc. bond rates for 2011 were based on the long term forecast from the October 2009 edition of Consensus Forecasts. Hydro One credit spreads are based on an average of indicative new issue spreads for November 2009 from the dealers in Hydro One's medium term note syndicate.

The 90-Day Banker's Acceptance Rate for 2010 was prepared based on the November 2009 edition of Consensus Forecasts; the remaining years were based upon the Global Insight November 2009 Long-Term Forecast and Analysis.

Interest capitalization rate – Forecast of Scotia Capital All-Corp Mid-Term Yield (from Treasury – November 2009).

COST OF CAPITAL SUMMARY

Hydro One Brampton's 2011 rate base is $335.1 million, which results in an after tax required return of 7.80% as shown in **Table 4**, below:

Table 4: 2011 Cost of Capital

Particulars	**2011**			
Amount of Deemed	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
Long-term debt	**187.6**	**56**	**6.76**	**12.7**
Short-term debt	**13.4**	**4**	**2.07**	**0.3**
Common equity	**134.0**	**40**	**9.92**	**13.3**
Total Rate Base	**335.1**	**100**	**7.84**	**26.3**

See Exhibit 5 Tab 2 Schedule 1.0 for Historical, Bridge and Test Year debt and equity summary schedules including return on rate base.

COPY OF DEBT INSTRUMENT(S)

The following pages contain a copy of the original Debt Instrument(s) document:

HYDRO ONE BRAMPTON NETWORKS INC.

NOTE

Principal Amount:	**$143,000,000**
Interest Rate:	6.95% per annum
Due:	June 1, 2032

FOR VALUE RECEIVED, HYDRO ONE BRAMPTON NETWORKS INC. (the "**Company**"), incorporated under the laws of the Province of Ontario and having its principal office and place of business at Brampton, Ontario, **PROMISES TO PAY** to or to the order of **HYDRO ONE INC.** ("**Hydro One**") at its offices at Toronto, Ontario or at such other place as Hydro One may designate, the principal amount of **$143,000,000** in lawful money of Canada, with interest on such amount at the rate calculated in the manner and payable at the times specified in this Note.

This Note is subject to redemption or repurchase before maturity by the Company, in whole or in part, on the same terms and conditions, *mutatis mutandis*, as those that apply to the Series 2 Medium-Term Notes issued by Hydro One pursuant to an indenture dated as of June 4, 2001 and a supplemental indenture dated as of June 22, 2001 (collectively, the "Indenture") and which were sold by way of a prospectus dated June 4, 2001 with a pricing supplement dated June 19, 2001. Hydro One shall and is unconditionally and absolutely authorized and directed by the Company to record on the grid attached hereto the date and amount of each prepayment on account of the principal paid to Hydro One on a partial redemption or repurchase of this Note and the resulting outstanding principal amount of this Note. Such notations, in the absence of manifest mathematical error, shall be *prima facie* evidence of such prepayments.

The outstanding principal amount of this Note shall become due and payable on June 1, 2032, together with all interest accrued thereon to that date.

The principal amount of this Note remaining from time to time unpaid and outstanding shall bear interest at a rate of 6.95% per annum from the date of this Note, payable semi-annually in arrears in equal instalments on each Series 2 Note Interest Payment Date. The first Series 2 Note Interest Payment Date will be December 1, 2001 for the period from and including November14, 2001. Interest will be payable in respect of each Series 2 Note Interest Period (after as well as before maturity, default and judgement, with interest on overdue interest at the same rate) on each Series 2 Note Interest Payment Date. Interest on this Note will be computed on the basis of a year of 365 days or 366 days, as the case may be, for the actual number of days elapsed and will accrue from day to day. Capitalized terms not defined herein shall have the meanings assigned to them in the Indenture.

This Note is not transferable or negotiable without the prior written consent of the Company.

The Company waives presentment for payment and notice of non-payment.

This Note shall be construed in accordance with and governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF the Company has executed this Note.

HYDRO ONE BRAMPTON NETWORKS INC.

By: 

EXHIBIT 5

TAB 2

RETURN ON EQUITY AND COST OF DEBT

CALCULATION OF RETURN ON EQUITY AND INTEREST EXPENSE

The Deemed Capital Structure for 2005 to 2009 historical years, 2010 Bridge Year, and the 2011 Test Year are as provided below.

Table 1: Deemed Capital Structure for 2005

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	141,636,680	55.00%	6.95%	9,843,749
Unfunded Short Term Debt				
Total Debt	141,636,680	55.00%		9,843,749
Common Share Equity	115,884,556	45.00%	9.00%	10,429,610
Total equity	115,884,556	45.00%		10,429,610
Total Rate Base	257,521,236	100.00%	7.87%	20,273,359

Table 2: Deemed Capital Structure for 2006

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	143,218,803	55.00%	6.95%	9,953,707
Unfunded Short Term Debt				
Total Debt	143,218,803	55.00%		9,953,707
Common Share Equity	117,179,021	45.00%	9.00%	10,546,112
Total equity	117,179,021	45.00%		10,546,112
Total Rate Base	260,397,824	100.00%	7.87%	20,499,819

Table 3: Deemed Capital Structure for 2007

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	155,943,906	57.50%	6.95%	10,838,102
Unfunded Short Term Debt				
Total Debt	155,943,906	57.50%		10,838,102
Common Share Equity	115,262,887	42.50%	9.00%	10,373,660
Total equity	115,262,887	42.50%		10,373,660
Total Rate Base	271,206,794	100.00%	7.82%	21,211,761

Table 4: Deemed Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	170,774,255	60.00%	6.95%	11,868,811
Unfunded Short Term Debt				
Total Debt	170,774,255	60.00%		11,868,811
Common Share Equity	113,849,504	40.00%	9.00%	10,246,455
Total equity	113,849,504	40.00%		10,246,455
Total Rate Base	284,623,759	100.00%	7.77%	22,115,266

Table 5: Deemed Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	178,887,148	60.00%	6.95%	12,432,657
Unfunded Short Term Debt				
Total Debt	178,887,148	60.00%		12,432,657
Common Share Equity	119,258,098	40.00%	9.00%	10,733,229
Total equity	119,258,098	40.00%		10,733,229
Total Rate Base	298,145,246	100.00%	7.77%	23,165,886

Table 6: Deemed Capital Structure for 2010

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	192,573,874	60.00%	6.87%	13,227,811
Unfunded Short Term Debt				
Total Debt	192,573,874	60.00%		13,227,811
Common Share Equity	128,382,583	40.00%	9.00%	11,554,432
Total equity	128,382,583	40.00%		11,554,432
Total Rate Base	320,956,457	100.00%	7.72%	24,782,244

Table 7: Deemed Capital Structure for 2011

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	187,641,343	56.00%	6.76%	12,686,619
Unfunded Short Term Debt	13,402,953	4.00%	2.07%	277,441
Total Debt	201,044,297	60.00%		12,964,060
Common Share Equity	134,029,531	40.00%	9.92%	13,295,729
Total equity	134,029,531	40.00%		13,295,729
Total Rate Base	335,073,828	100.00%	7.84%	26,259,789

EXHIBIT 6

CALCULATION OF REVENUE

DEFICIENCY

EXHIBIT 6

TAB 1

REVENUE DEFICIENCY

SUMMARY

The information in this Exhibit supports Hydro One Brampton's request in this Application for an increase in its revenue requirement. Hydro One Brampton requires this increase in order to implement its capital and operating budgets for 2011 so that it can;

- Continue to provide a safe and reliable supply of electricity to the customers it serves,
- Earn its regulated rate of return, including its return on equity and return required to service its debt, and
- Pay its' deemed PILs Income Taxes.

The Applicant has determined that its Revenue Deficiency for the 2011 Test Year is $4,042,406. This Revenue Deficiency is the shortfall in Hydro One Brampton's revenue requirement needed to enable the Company to earn its' regulated Return on Rate Base. The calculations which this deficiency is based on are set out in the subsections that follow.

The 2011 Test Year revenue deficiency calculation does not include the following, which are discussed elsewhere in this Application:

- Energy Costs and Revenues are not included in the revenue deficiency calculations as these are not part of the Revenue Requirement;
- Deferral and Variance Account rate riders, which are not recorded as revenue, but rather as dispositions of balance sheet account balances;
- Smart Meter final disposition rate rider for disposition of Smart Meter deferral accounts 1555 and 1556 to December 31, 2009;
- Smart Meter ongoing funding adder for recovery of 2010 Bridge Year revenue requirement and further Smart Meter revenue requirement on additional Smart Meter investments for disposition in a future application to the Board, and
- Proposed LRAM and SSM-related rate riders.

The Revenue Requirement Model can be viewed in Exhibit 11 Tab 1 Schedule 8.

REVENUE DEFICIENCY - OVERVIEW

Hydro One Brampton's revenue deficiency of $4,042,406 is the difference between its deemed 2011 Test Year Revenue Requirement of $66,581,755 and the forecast 2011 Test Year Revenue Requirement of $62,539,349 at existing distribution rates.

REVENUE REQUIREMENT

Hydro One Brampton's revenue requirement is comprised of the following components:

- Operation, Maintenance, and Administration Expense;
- Amortization Expense;
- PILs Income Tax; and
- Return on Rate Base (Debt Interest Expense + Return on Equity).

Hydro One Brampton mainly derives its service revenue requirement through distribution rates charged to customers. Other revenues are received from OEB-approved specific service charges; rent from electric property; late payment charges; interest; and other miscellaneous sources. These other revenues are described in detail in Exhibit 3 and are treated as offsets against Hydro One Brampton's service revenue requirement to calculate the base revenue requirement upon which class-specific distribution rates are calculated.

For detailed 2011 Test Year Revenue Requirement calculations see Exhibit 11 Tab 1 Schedule 8: Revenue Requirement Model.

DETERMINATION OF NET INCOME

Based on the existing 2010 OEB Approved Rates, Hydro One Brampton has determined that its 2011 Test Year Net Income would be $10,395,303. The Company requires an after tax net income of $13,295,729 for the 2011 Test Year in order to earn its' regulated rate of return. The following **Table 1: Determination of Net Utility Income** provides the net income calculations and the associated net and gross revenue deficiencies for the 2006 OEB Approved rebasing year, the actual from 2006 to 2009, the 2010 Bridge Year and the 2011 Test Year at Existing Rates and the Revenue Deficiencies by year.

Table 1: Determination of Net Utility Income

	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Distribution Revenue	53,394,209	57,455,803	59,795,225	60,262,873	60,935,610	59,611,677	58,552,937
Other Revenue	3,008,438	5,092,690	4,571,062	4,061,417	3,789,918	3,883,514	3,986,412
Total Operating Revenue	56,402,647	62,548,493	64,366,287	64,324,291	64,725,528	63,495,191	62,539,349
Operation, Maintenance, and Administration	13,748,003	16,155,651	15,925,811	17,173,680	17,836,429	24,040,769	25,306,728
Amorization Expense	12,792,510	15,278,462	15,598,345	16,216,369	17,450,905	13,145,166	12,494,579
Capital Taxes	864,244	857,800	715,082	694,022	938,034	240,386	-
Interest Expense	9,527,121	9,953,707	10,838,102	11,868,811	12,432,657	13,227,811	12,964,060
Total Utility Expenses	36,931,878	42,245,620	43,077,339	45,952,883	48,658,024	50,654,132	50,765,367
Net Income Before Taxes	19,470,769	20,302,874	21,288,948	18,371,408	16,067,504	12,841,059	11,773,982
PILs Income Taxes	9,376,631	8,717,686	11,490,612	7,557,747	7,502,104	1,894,924	1,378,679
Net Income After PILs Income Taxes	10,094,138	11,585,188	9,798,336	10,813,661	8,565,399	10,946,135	10,395,303
Required Net Income After PILs Income Taxes	10,094,138	10,546,112	10,373,660	10,246,455	10,733,229	11,554,432	13,295,729
Net Income Sufficiency/(Deficiency)	0	1,039,076	(575,324)	567,206	(2,167,829)	(608,297)	(2,900,426)
Gross Income Sufficiency/(Deficiency)	0	1,626,606	(900,632)	852,941	(3,235,566)	(881,590)	(4,042,406)

Table 2 below provides the detail calculations to determine the 2011 Test Year Revenue Deficiency. As can be seen, in order that Hydro One Brampton earns its regulated return on equity, it must earn after tax net income of $13,295,729.

Table 2: 2011 Test Year Revenue Deficiency Determination

	2011 Test - Existing Rates	2011 Test - Required Revenue
Revenue		
Additional Revenue Requirement		4,042,406
Distribution Revenue	58,552,937	58,552,937
Other Operating Revenue (Net)	3,986,412	3,986,412
Total Revenue	62,539,349	66,581,755
Costs and Expenses		
Administrative & General, Billing & Collecting, Community Relations	14,416,233	14,416,233
Operation & Maintenance	10,890,495	10,890,495
Depreciation & Amortization	12,494,579	12,494,579
Capital Taxes	-	-
Deemed Interest	12,964,060	12,964,060
Total Costs and Expenses	50,765,367	50,765,367
Utility Income Before Income Taxes	11,773,982	15,816,388
Income Taxes:		
Corporate Income Taxes	1,378,679	2,520,658
Utility Net Income	10,395,303	13,295,729
Income Tax Expense Calculation:		
Accounting Income	11,773,982	15,816,388
Tax Adjustments to Accounting Income	(6,893,703)	(6,893,703)
Taxable Income	4,880,279	8,922,685
Income Tax Expense	1,378,679	2,520,658
	28.25%	28.25%
Actual Return on Rate Base:		
Rate Base	335,073,828	335,073,828
Interest Expense	12,964,060	12,964,060
Net Income	10,395,303	13,295,729
Total Actual Return on Rate Base	23,359,363	26,259,789
Actual Return on Rate Base	6.97%	7.84%
Deemed Interest Expense	12,964,060	12,964,060
Return On Equity	13,295,729	13,295,729
Total Return	26,259,789	26,259,789
Expected Return on Rate Base	7.84%	7.84%
Revenue Deficiency After Tax	**2,900,426**	**0**
Revenue Deficiency Before Tax	**4,042,406**	**0**

STATEMENT OF RATE BASE & REQUESTED RETURN

Hydro One Brampton has provided a summary of its rate base for the 2006 Board Approved, 2006 to 2009 Actual Years, 2010 Bridge Year and the 2011 Test Year calculated based on the Company's deemed capital structure in accordance with the Filing Requirements. The rate base of $335,073,828 is used to calculate HOBNI's requested return at 7.84% in the amount of $26,259,789 for the 2011 Test Year.

Hydro One Brampton's rate base and requested return are summarized in **Table 3** below, **Table 4** summarizes the Working Capital Allowance and **Table 5** summarizes the Rate of Return on Rate Base.

Table 3: 2011 Test Year Rate Base

RATE BASE CALCULATION FOR 2011	
Fixed Assets Opening Balance 2011	276,108,517
Fixed Assets Closing Balance 2011	285,923,468
Average Fixed Asset Balance for 2011	281,015,992
Working Capital Allowance	54,057,835
Rate Base	335,073,828
Regulated Rate of Return	7.84%
Regulated Return on Capital	26,259,789
Deemed Interest Expense	12,964,060
Deemed Return on Equity	13,295,729

Table 4: 2011 Test Year Working Capital Allowance

WORKING CAPITAL ALLOWANCE FOR 2011	
Distribution Expenses	**$**
Distribution Expenses - Operation	6,854,992
Distribution Expenses - Maintenance	4,035,503
Billing and Collecting	5,656,663
Community Relations	640,000
Administrative and General Expenses	8,119,570
Taxes Other than Income Taxes	-
Less: Capital Taxes within 6105	-
Total Eligible Distribution Expenses	**25,306,728**
Power Supply Expenses	335,078,839
Total Working Capital Expenses	360,385,567
Working Capital Allowance rate of 15%	54,057,835

Table 5: Rates of Return on Rate Base

2011		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	6.76%
Short-Tern Debt	4.00%	2.07%
Return On Equity	40.00%	9.92%
Weighted Debt Rate		6.45%
Regulated Rate of Return		7.84%

ACTUAL UTILITY RETURN ON RATE BASE

Hydro One Brampton's Actual Return on Rate base for 2006 to 2009 at OEB approved rates, 2010 Bridge Year forecast, and the forecast return on rate base for the 2011 Test Year forecast at existing rates is summarized below. Data based on annual financial statement information submitted in Exhibit 11 Tab 1 Schedule 8: Revenue Requirement Model.

Table 6: Actual Return on Rate Base

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge - Forecast	2011 Test - Forecast - At 2010 Rates
Actual Rate Base	260,397,824	271,206,794	284,623,759	298,145,246	320,956,457	335,073,828
Actual Net Income	11,503,784	10,523,234	11,987,272	10,267,005	10,946,135	10,395,303
Actual Interest Expense	10,255,139	10,260,655	10,143,835	9,833,688	13,227,811	12,964,060
Return on Rate Base	21,758,923	20,783,889	22,131,107	20,100,692	24,173,946	23,359,363
Actual Return on Rate Base	8.36%	7.66%	7.78%	6.74%	7.53%	6.97%

INDICATED AND REQUESTED RATE OF RETURN ON RATE BASE

HOBNI has determined its' required rate of return on rate base to be 7.84% as explained in detail in Exhibit 5, Tab 2, Schedule 1.0, above. Summarized in the following **Table 7: Indicated & Requested Rate of Return** is the indicated rate of return on rate base and Hydro One Brampton's requested rate of return on rate base for each of the 2006 Board Approved, 2006 – 2009 Actual Years, 2010 Bridge Year and the 2011 Test Year.

Table 7: Indicated and Requested Rate of Return

	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Rate Base - Exhibit 2	249,237,964	260,397,824	271,206,794	284,623,759	298,145,246	320,956,457	335,073,828
Indicated Return on Rate Base:							
Net Income	10,094,138	11,585,188	9,798,336	10,813,661	8,565,399	10,946,135	10,395,303
Interest Expense (Return on Debt Equity)	9,527,121	9,953,707	10,838,102	11,868,811	12,432,657	13,227,811	12,964,060
Indicated Return on Rate Base	19,621,259	21,538,895	20,636,438	22,682,472	20,998,056	24,173,946	23,359,363
Indicated Rate of Return	7.87%	8.27%	7.61%	7.97%	7.04%	7.53%	6.97%
Requested Return on Rate Base:							
Requested Net Income	10,094,138	10,546,112	10,373,660	10,246,455	10,733,229	11,554,432	13,295,729
Requested Interest Expense	9,527,121	9,953,707	10,838,102	11,868,811	12,432,657	13,227,811	12,964,060
Requested Return on Rate Base	19,621,259	20,499,819	21,211,761	22,115,266	23,165,886	24,782,244	26,259,789
Requested Rate of Return	7.87%	7.87%	7.82%	7.77%	7.77%	7.72%	7.84%
Net Revenue Sufficiency/(Deficiency)	0	1,039,076	(575,324)	567,206	(2,167,829)	(608,297)	(2,900,426)
Gross Revenue Sufficiency/(Deficiency)*	0	1,626,606	(900,632)	852,941	(3,235,566)	(881,590)	(4,042,406)

* - Calculated as the net revenue sufficiency/(deficiency) divided by (one minus the corportate tax rate)

HOBNI's Net Revenue Deficiency for the 2011 Test Year is $2,900,426. Grossed up for taxes of 28.25% is $4,042,406.

DEFICIENCY OR SUFFICIENCY IN REVENUE

Table 8: Deficiency of Sufficiency in Revenue

	2006 OEB Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Operation, Maintenance, and Administration	13,748,003	16,155,651	15,925,811	17,173,680	17,836,429	24,040,769	25,306,728
Amorization Expense	12,792,510	15,278,462	15,598,345	16,216,369	17,450,905	13,145,166	12,494,579
Capital Taxes	864,244	857,800	715,082	694,022	938,034	240,386	-
Interest Expense	9,527,121	9,953,707	10,838,102	11,868,811	12,432,657	13,227,811	12,964,060
PILs Taxes	9,376,631	8,130,156	11,815,920	7,272,011	8,569,841	2,168,217	2,520,658
Return On Equity	10,094,138	10,546,112	10,373,660	10,246,455	10,733,229	11,554,432	13,295,729
Service Revenue Requirement - 1	56,402,647	60,921,887	65,266,919	63,471,349	67,961,095	64,376,782	66,581,755
Distribution Revenue At Current Rates - 2	53,394,209	57,455,803	59,795,225	60,262,873	60,935,610	59,611,677	58,552,937
Other Revenue	3,008,438	5,092,690	4,571,062	4,061,417	3,789,918	3,883,514	3,986,412
Total Operating Revenue	56,402,647	62,548,493	64,366,287	64,324,291	64,725,528	63,495,191	62,539,349
Service Revenue Sufficiency/(Deficiency)	0	1,626,606	(900,632)	852,941	(3,235,566)	(881,590)	(4,042,406)

1 - Note the Service Revenue Requirements for 2006 Actuals to 2010 Bridge Year include Smart Meter amounts to facilitate year over year comparability.

2 - Note the actuals for 2006 to 2009 are based on rates in effect for the rate year multiplied by historical actual normalized throughput quantities. The 2011 Test Year is based on 2010 OEB Approved Rates multiplied by forecast throughput quantities.

The total Service Revenue Requirement for the 2011 Test Year is $66,581,755. Based on existing 2010 rates and 2011 forecast billing determinants, the total Service Revenue for the 2011 Test Year would be $62,539,349. For the 2011 Test Year the Service Revenue would have to increase by $4,042,406 to eliminate this revenue deficiency.

EXHIBIT 7

COST ALLOCATION

EXHIBIT 7

TAB 1

COST ALLOCATION STUDY REQUIREMENTS

COST ALLOCATION STUDY OVERVIEW

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model.

A primary objective of the cost allocation review was to provide information on the revenue to cost ratios among distributors' rate classifications. It was felt that this information would be useful in identifying cross subsidization between classes. As well, the filings would be useful tools in subsequent cost of service electricity distribution rate applications.

On January 15th, 2007, Hydro One Brampton filed with OEB its Cost Allocation Informational Filing. The Company utilized the Standard Cost Allocation Model Version 1.2 Spreadsheet as provided by the OEB as the sole mechanism used to prepare the filing.

The complete Cost Allocation Study can be viewed in Exhibit 11 Tab 1 Schedule 2.

2006 COST ALLOCATION INFORMATIONAL FILING RESULTS

Hydro One Brampton utilized the services of the Hydro One Load Data Team to prepare the utility specific load profiles. In addition, Hydro One Brampton undertook an updated residential appliance saturation survey for its customers on its own; it was not jointly prepared, nor borrowed from another distributor. The survey occurred between February and May 2006. Consistent with the guidelines, Hydro One Brampton's assets were broken out into primary and secondary distribution functions. The breakout of this information was developed from the best data available from its engineering records and customer and financial information systems.

At this time, the Embedded Distributor and Street Light rate classes had only one customer in each class. Hydro One Brampton consolidated the Embedded Distributor information with the GS 700 to 4,999 kW class and the Street Light information was aggregated with the Sentinel Light class. The aggregated classes were chosen on a basis of which class it shared more attributes with for the purpose of this filing.

The Back up/Standby Power class was applicable to only one customer in HOBNI's service territory. This Back up/Standby Power rate, was and still is, a supplemental rate and is not

considered to be a rate class. Exclusion of this class did not materially impact the results of that filing.

Run 1 reflected Hydro One Brampton's approved rate classifications at that time, with the exception of its Back up/Standby Power class, which was approved on an interim basis.

The following rate classes were modeled in Run 1:

- Residential
- General Service (GS) < 50 kW
- General Service (GS) > 50 kW - Regular (50 to 699 kW)
- General Service (GS) > 50 - Intermediate (700 to 4999 kW) / Embedded Distributor
- Large Use (>50MW)
- Street Lighting / Sentinel

Unmetered Scattered Load (USL) was not included in Run 1 as the 2006 EDR approved rates reflected USL as a part of the GS<50 kW rate classification. No separate revenue requirement was determined for this class in the 2006 EDR process.

The following rate classes have been modeled in Run 2:

- Residential
- General Service (GS) < 50 kW
- General Service (GS) > 50 kW - Regular (50 to 699 kW)
- General Service (GS) > 50 - Intermediate (700 to 4999 kW) / Embedded Distributor
- Large Use (>5.0MW)
- Street Lighting / Sentinel
- Unmetered Scattered Load (USL)

The results of a cost allocation study are presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being

subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following **Table 1** outlines the revenue to cost ratios from the Cost Allocation Informational Filing submitted by HOBNI on January 15th, 2007. The calculations are based on HOBNI's OEB-approved 2006 electricity distribution rates.

Table 1: Summary of 2006 Model Results

Rate Class	Revenue to Expenses %	
	Run 1	Run 2
Residential	105.98%	105.80%
GS < 50 kW	120.41%	122.38%
GS > 50 kW - Regular	64.05%	64.05%
GS > 50 – Intermediate	149.65%	149.68%
Large Use (>5.0MW)	95.38%	95.39%
Street Lighting / Sentinel	10.63%	10.63%
Unmetered Scattered Load	N/A	87.52

2010 COST ALLOCATION FILING RESULTS

Hydro One Brampton is using the Cost Allocation methodology recommended by the Board in its September 29, 2006 report, Proceeding EB-2005-0317, to allocate the revenue requirement by customer group. In addition, Hydro One Brampton has prepared its 2011 cost allocation filing in accordance with Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued May 27, 2009.

Hydro One Brampton utilized the services of the Hydro One Load Data Team to prepare the utility specific load profiles for all classes. All financial data and weather normalized load forecast data utilized in the cost allocation process is consistent with information presented in this 2011 rate application. In addition, the Company has removed the costs and revenues associated with the transformer allowance as required under section 2.8.2 The Treatment of

Transformer Ownership Allowance page 20 of "Chapter 2 - Filing Requirements for Transmission and Distribution Applications" issued on May 27, 2009.

CUSTOMER CLASSIFICATION

Hydro One Brampton has not modeled any new classes in this 2011 cost allocation model, as it does not have any significant changes to its operations, following its 2006 EDR test year. It should be noted that since the filing of Hydro One Brampton's 2006 EDR test year, 2004, to December 31, 2009 Hydro One Brampton has connected approximately 21,000 new customers. This represents growth in customer numbers during the period of 18.7%. Most of these new customers are residential.

HOBNI has modeled the following customer classification in this cost allocation filing. All of these customer classifications are currently approved by the OEB.

1. Residential
2. General Service < 50 kW
3. General Service 50 – 699 kW
4. General Service 700 – 4999 kW
5. Large Use > 5000 kW
6. Street Lighting
7. Unmetered Scattered Load (USL)

In addition to these customer classes Hydro One Brampton has a series of other approved classes that were not modeled in this cost allocation model. They are as follows:

Standby Power

Hydro One Brampton currently has an approved Standby Rate for Load Displacement Generation (LDG) customers (above 500 kW demand). Hydro One Brampton currently has only one LDG customer in its territory. Due to the operational requirements of this customer, Hydro One Brampton has not had to levy a Standby charge on this customer for several years. Due to the lack of application of the Standby Rate, for the purpose of this cost allocation filing, a Load Displacement Generation class has not been modeled. The Company is proposing to maintain the current rate as an approved rate in case there becomes a need for it in the future.

Embedded Distributor

In the 2006 cost allocation filing Hydro One Brampton consolidated the Embedded Distributor information with the Intermediate class. Hydro One Brampton then applied for and received approval for an LV Wheeling charge that was to be applied to the embedded distributor. Revenues from this charge have been credited to the LV variance account to offset these costs. The revenues associated with this embedded distributor and the LV rate were approximately $2,200 for 2009. Over the past several years the load supplied to this distributor has been declining. In light of this, and its relatively low impact on revenues, Hydro One Brampton has opted not to include this as a class to be modeled in this cost allocation filing. Hydro One Brampton is proposing to maintain the current rate as an approved rate and will continue to credit this revenue to the LV variance account.

Sentinel Lighting

Over the past several years, Hydro One Brampton has made efforts to remove all of its sentinel lights from its system. These lights have either been removed from the system or are now the customer's responsibility. As a result, Hydro One Brampton no longer has any sentinel lighting customers or volumetrics to include in the cost allocation model.

microFIT Generator

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. There is no volumetric component associated with this classification therefore this rate class was not modeled in the cost allocation model.

EXHIBIT 7

TAB 2

REVENUE TO COST RATIOS

PROPOSED REVENUE TO COST RATIOS

Section 3.7 of the OEB Staff Discussion Paper on the Implications Arising from Review of the Electricity Distributor's Cost Allocation Filings (EB-2007-0667), OEB staff proposed certain acceptable bands of revenue to cost ratios. **Table 1** below identifies these required ranges proposed by OEB staff. This table also identifies the current and proposed revenue to cost ratios for all customer classifications.

Section 3.5 of the Review of the Electricity Distributor's Cost Allocation Filings states: "Any distributor with a class ratio that falls outside the suggested ranges should re-align its distribution rates so that all classes fall within the respective ranges." Hydro One Brampton is proposing to re-align its revenue to cost ratio in this application by adjusting the allocations of revenue among its rate classes in order to reduce the cross- subsidization.

Table 1 below identifies and summarizes the revenue to cost ratios of the 2006 and 2011 cost allocations. In addition, the table further identifies the revenue to cost ratios of the 2011 cost allocation results with and without the transformer corrected values. Hydro One Brampton is proposing to implement a partial shift towards full cost of service. In order to achieve this, revenue to cost ratios must be realigned closer to unity. Table identifies Hydro One Brampton's proposed revenue to cost ratios for each class that are required in order to reduce cross-subsidization impacts.

Table 1: Revenue to Cost Ratio Analysis for 2011 Cost of Service Rate Application

	2006 Cost Allocation Ratios - As Filed	2011 Cost Allocation Ratios - Before Tx Correction	2011 Cost Allocation Ratios - Tx Corrected	2011 Cost Allocation Ratios - Applied For	Class Impact % of Existing Rates	Class Impact % Change	OEB Required Range
Residential	105.8%	95.6%	105.1%	102.5%	97.4%	-2.6%	85% - 115%
GS <50	122.4%	136.7%	133.5%	117.5%	87.3%	-12.7%	80% - 120%
GS>50-Regular	64.1%	76.7%	72.0%	80.0%	111.3%	11.3%	80% - 180%
GS 700 - 4,999	149.7%	179.0%	148.1%	131.3%	88.7%	-11.3%	80% - 180%
Large Use >5MW	95.4%	132.7%	97.1%	100.0%	102.4%	2.4%	85% - 115%
Street Light	10.6%	20.1%	19.0%	70.0%	919.6%	819.6%	70% - 120%
USL	87.5%	84.0%	77.6%	90.0%	128.7%	28.7%	80% - 120%

REVENUE TO COST RATIO ANALYSIS

Table 1 on the previous page illustrates that there are several rate classifications that fall outside of the OEB staff proposed acceptable bands of revenue to cost ratios. Adjusting a rate class revenue to cost ratio that is currently above the acceptable bands down to the upper limit of the recommended band limit will allocate costs from that class to all other rate classes. Conversely, for the various classes that currently have revenue to cost ratios below the minimum recommended band, adjusting the ratios upward will transfer additional costs to said classes from other classes, thus reducing the costs for the other classes.

Hydro One Brampton currently has four of the seven rate classes that have revenue to cost ratios that are outside of the OEB staff proposed acceptable bands. They are as follows:

General Service < 50 kW

Currently this customer class has a revenue to cost ratio of 133.5% (Transformer Ownership Allowance corrected). This indicates that this rate class has been over contributing, and as such, has been subsidizing other rate classes. In an effort to mitigate this class from over contributing, Hydro One Brampton is proposing a revenue to cost ratio of 117.5%. This will allow this class to fall within the OEB staff proposed acceptable band of revenue to cost ratios for this class.

General Service 50 – 699 kW

With a revenue to cost ratio of 72.0% this customer class is currently below the minimum OEB staff proposed acceptable revenue to cost ratio band for this class. Revenue derived from this class has been insufficient to cover the costs of servicing this class. As a result, this class has been partially subsidized by other classes. In order to bring this customer class with in the bands recommended by OEB staff, Hydro One Brampton is proposing to adjust this revenue to cost ratio to 80.0%. HOBNI is concerned that adjusting this class any closer to a unity revenue to cost ratio may cause rate shock to this class.

Street Lighting

It is not uncommon to find that on an initial cost allocation model, that the Street Lighting class has been grossly under contributing in terms of its fare share of costs. In Hydro One Brampton's case, Street Lighting has a revenue to cost ratio of 19.0%. Revenue derived from this class has been insufficient to cover the costs of servicing this class.

HOBNI is proposing to re-align the revenue to cost ratio to 70.0%, the lower limit of the OEB staff's proposed acceptable revenue to cost ratio band for this class.

Unmetered Scattered Load (USL)

Currently this customer class has a revenue to cost ratio of 77.6%. This indicates that this rate class has been slightly under contributing, and as such, has been subsidized by other rate classes. In an effort to mitigate this class from under contributing, Hydro One Brampton is proposing a revenue to cost ratio is 90.0%. This will allow this class to fall within the OEB staff proposed acceptable band of revenue to cost ratios for this class.

Although the remaining classes currently fall within the respective ranges that OEB staff proposed, Hydro One Brampton would like to take this opportunity to move these classes closer to revenue to cost ratios of 100%

Residential

Currently this customer class has a revenue to cost ratio of 105.1%. Hydro One Brampton is proposing a revenue to cost ratio of 102.50%.

General Service 700 – 4,999 kW

This class currently has a revenue to cost ratio of 148.1%. Although within the OEB staff proposed bands, HOBNI would like to migrate this customer class to a revenue to cost ratio of 131.3%. This will help to mitigate the over contribution that this class is currently responsible for.

Large Use > 5000 kW

Currently this customer class has a revenue to cost ratio of 97.1%. Hydro One Brampton is proposing a revenue to cost ratio of 100.0%. This will help to reduce the under contribution associated with this class.

COST ALLOCATION RESULTS

The discussion and tables above support HOBNI's proposed reallocation of distribution costs across customer classes, in order to begin moving toward revenue to cost ratios of 100% and reduce cross-subsidization. HOBNI submits that the proposed reallocation of distribution revenue is fair and reasonable for the following reasons:

Customer class revenues will more closely reflect the actual costs of providing distribution service to those classes;

- Customer class revenues will more closely reflect the actual costs of providing distribution services to that class;
- Rate impacts on total bill is less than the mitigation threshold across all classes, with the exception of the Street Light class;
- Partial reallocation provides adjustment time for the customer and further refinement of the cost allocation model and movement between classes.

Below are the Results of the Revenue to Cost Ratios per the Cost Allocation Study submitted with this rate application, as follows:

Table 1: Revenue to Cost Ratios

Revenue to Cost Ratio

Customer Class	(1) From Cost Allocation Model	(2) Column 1 Revised (Transformer Ownership Allowance)	(3) Proposed for Test Year	(4) Board Target Range
Residential	95.6%	105.1%	102.5%	85% - 115%
GS <50	136.7%	133.5%	117.5%	80% - 120%
GS>50-Regular	76.7%	72.0%	80.0%	80% - 180%
GS >50-Intermediate	179.0%	148.1%	131.3%	80% - 180%
Large Use >5MW	132.7%	97.1%	100.0%	85% - 115%
Street Light	20.1%	19.0%	70.0%	70% - 120%
USL	84.0%	77.6%	90.0%	80% - 120%

Total Revenues at current levels based on 2010 OEB approved rates compared to Test Year Revenues at existing Revenue to Cost ratios, and Test Year Revenues based on proposed Revenue to Cost Ratios, as follows:

Table 2: Test Year Revenue Impacts

Test Year Revenue Impacts

Customer Class	Current Revenues	Test Year Revenue Assuming Current Revenue to Cost Ratios	Test Year Revenue Assuming Proposed Revenue to Cost Ratios
Residential	$ 32,611,130	$ 34,862,553	$ 33,931,976
GS <50	$ 7,083,429	$ 7,572,458	$ 6,619,012
GS>50-Regular	$ 8,764,421	$ 9,369,504	$ 10,468,422
GS >50-Intermediate	$ 7,861,805	$ 8,404,573	$ 7,430,218
Large Use >5MW	$ 1,935,349	$ 2,068,962	$ 2,134,304
Street Light	$ 194,594	$ 208,028	$ 1,883,530
USL	$ 102,209	$ 109,266	$ 127,882

Revised Transformer Allowances

Outputs of the Cost Allocation Model include updated Line Transformer Unit Costs by customer Class. The following per kW unit costs are produced in O3.1 Line Tran Unit Cost of the Cost Allocation Model.

General Service > 50 to 699 kW - $0.7202

General Service 700 to 4,999 kW - $0.8952

Large User - $0.0000

Hydro One Brampton has updated it's Transformer Ownership Allowances so that they are consistent with the cost incurred to provide this service to customers who do not own their own Transformers, since these are effectively Hydro One Brampton's avoided costs.

All Hydro One Brampton Large Use customers are supplied from the Company's primary distribution system and therefore have a share of the associated costs of Hydro One Brampton's primary distribution system allocated accordingly. However, by virtue of being supplied from the primary distribution system, the Large User customer does not have an allocation of transformation or secondary costs assigned to it. The OEB's cost allocation Model allocated costs correctly for primary connected customers. The Model also correctly eliminates the provision of a Transformer Allowance for this primary supplied customer class, as there are no related transformation costs assigned to this class. The Large Use customer class will no longer receive the Transformer Allowance effective January 1, 2011 subject to OEB approval of this rate application and corresponding implementation date.

TRANSFORMER OWNERSHIP ALLOWANCE CORRECTED COST ALLOCATION

In adherence to section 2.8.2 of the OEB Chapter 2 Filing requirements for this rate application, Hydro One Brampton has provided two additional output sheets for tab “O1 – Revenue to cost|RR”. The first is the tab before the correct to the Cost Allocation model for the Transformer Ownership Allowance limitation of the model, and the second is the resulting output sheet O1 after the correction for this limitation in the model.

Below is Output Sheet "O1 – Revenue to cost RR" prior to correction of the Cost Allocation model for the Transformer Ownership Allowance limitation of the model.

2011 COST ALLOCATION INFORMATION FILING
Hydro One Brampton Networks Inc.
EB-2010-0132
Tuesday, June 01, 2010
Sheet O1 Revenue to Cost Summary Worksheet - First Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$62,595,343	$33,931,976	$6,619,012	$10,468,422	$7,430,218	$2,134,304	$1,883,530	$127,882
mi	Miscellaneous Revenue (mi)	$3,986,412	$2,443,358	$369,847	$488,883	$174,116	$89,025	$414,175	$7,008
	Total Revenue	$66,581,755	$36,375,334	$6,988,859	$10,957,305	$7,604,334	$2,223,328	$2,297,705	$134,890
	Expenses								
di	Distribution Costs (di)	$9,056,549	$4,723,848	$743,797	$1,929,602	$860,874	$371,945	$398,544	$27,939
cu	Customer Related Costs (cu)	$7,490,609	$4,761,878	$649,852	$815,902	$265,520	$8,143	$976,140	$13,175
ad	General and Administration (ad)	$8,759,570	$5,019,697	$737,920	$1,455,033	$597,120	$201,670	$726,372	$21,757
dep	Depreciation and Amortization (dep)	$12,494,579	$6,555,039	$1,190,251	$2,798,878	$1,123,221	$443,299	$357,871	$26,019
INPUT	PILs (INPUT)	$2,520,658	$1,263,609	$230,004	$586,558	$258,074	$104,947	$72,125	$5,341
INT	Interest	$12,964,060	$6,498,897	$1,182,939	$3,016,739	$1,327,309	$539,757	$370,947	$27,472
	Total Expenses	$53,286,025	$28,822,968	$4,734,762	$10,602,712	$4,432,119	$1,669,762	$2,901,998	$121,703
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$13,295,729	$6,665,163	$1,213,203	$3,093,919	$1,361,267	$553,566	$380,437	$28,175
	Revenue Requirement (includes NI)	$66,581,755	$35,488,131	$5,947,965	$13,696,631	$5,793,386	$2,223,328	$3,282,435	$149,877
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$301,617,053	$152,052,528	$27,478,073	$69,731,254	$30,477,400	$12,416,669	$8,811,806	$649,323
gp	General Plant - Gross	$13,849,839	$6,963,523	$1,257,514	$3,209,853	$1,408,538	$574,532	$405,948	$29,930
accum dep	Accumulated Depreciation	($18,421,995)	($9,665,667)	($1,765,004)	($4,097,673)	($1,676,264)	($668,904)	($511,161)	($37,321)
co	Capital Contribution	($16,028,901)	($8,461,148)	($1,333,297)	($3,460,826)	($1,445,381)	($623,828)	($658,421)	($45,999)
	Total Net Plant	$281,015,996	$140,889,236	$25,637,286	$65,382,607	$28,764,294	$11,698,469	$8,048,172	$595,933
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$335,078,839	$98,398,444	$25,823,900	$99,821,387	$73,909,904	$34,044,737	$2,645,233	$435,235
	OM&A Expenses	$25,306,728	$14,505,423	$2,131,568	$4,200,537	$1,723,514	$581,759	$2,101,056	$62,871
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$360,385,567*	*$112,903,867*	*$27,955,468*	*$104,021,924*	*$75,633,418*	*$34,626,496*	*$4,746,289*	*$498,106*
	Working Capital	$54,057,835	$16,935,580	$4,193,320	$15,603,289	$11,345,013	$5,193,974	$711,943	$74,716
	Total Rate Base	$335,073,831	$157,824,816	$29,830,606	$80,985,896	$40,109,306	$16,892,443	$8,760,116	$670,649
		Rate Base Input equals Output							
	Equity Component of Rate Base	$134,029,533	$63,129,926	$11,932,242	$32,394,358	$16,043,723	$6,756,977	$3,504,046	$268,260
	Net Income on Allocated Assets	$13,295,730	$7,552,366	$2,254,097	$354,593	$3,172,214	$553,566	($604,294)	$13,187
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$13,295,730	$7,552,366	$2,254,097	$354,593	$3,172,214	$553,566	($604,294)	$13,187
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	102.50%	117.50%	80.00%	131.26%	100.00%	70.00%	90.00%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$0	$887,203	$1,040,894	($2,739,326)	$1,810,947	$0	($984,731)	($14,988)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.92%	11.96%	18.89%	1.09%	19.77%	8.19%	-17.25%	4.92%

Below is Output Sheet "O1 – Revenue to cost RR" after the correction of the Cost Allocation Model for the Transformer Ownership Allowance limitation of the model.

2011 COST ALLOCATION INFORMATION FILING

Hydro One Brampton Networks Inc.

EB-2010-0132

Tuesday, June 01, 2010

Sheet O1 Revenue to Cost Summary Worksheet - First Run

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$64,099,625	$32,286,079	$7,967,940	$10,369,730	$10,260,804	$2,838,972	$252,972	$123,128
mi	Miscellaneous Revenue (mi)	$3,986,412	$2,443,360	$369,847	$488,883	$174,115	$89,024	$414,175	$7,008
	Total Revenue	$68,086,036	$34,729,439	$8,337,787	$10,858,613	$10,434,919	$2,927,995	$667,147	$130,136
	Expenses								
di	Distribution Costs (di)	$10,560,831	$5,561,236	$886,212	$2,325,166	$918,995	$371,932	$464,741	$32,548
cu	Customer Related Costs (cu)	$7,490,609	$4,761,878	$649,852	$815,902	$265,520	$8,143	$976,140	$13,175
ad	General and Administration (ad)	$8,759,570	$5,007,626	$745,527	$1,525,666	$575,695	$184,945	$697,934	$22,178
dep	Depreciation and Amortization (dep)	$12,494,579	$6,557,936	$1,189,886	$2,797,038	$1,122,863	$442,566	$358,218	$26,073
INPUT	PILs (INPUT)	$2,520,658	$1,263,617	$230,005	$586,557	$258,070	$104,944	$72,124	$5,341
INT	Interest	$12,964,060	$6,498,938	$1,182,942	$3,016,734	$1,327,287	$539,742	$370,945	$27,471
	Total Expenses	$54,790,307	$29,651,230	$4,884,423	$11,067,062	$4,468,429	$1,652,273	$2,940,102	$126,787
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$13,295,729	$6,665,205	$1,213,206	$3,093,914	$1,361,244	$553,551	$380,435	$28,174
	Revenue Requirement (includes NI)	$68,086,036	$36,316,436	$6,097,629	$14,160,976	$5,829,673	$2,205,823	$3,320,538	$154,961
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$301,617,053	$152,053,419	$27,478,144	$69,731,160	$30,476,904	$12,416,342	$8,811,766	$649,318
gp	General Plant - Gross	$13,849,839	$6,963,564	$1,257,518	$3,209,848	$1,408,516	$574,517	$405,947	$29,930
accum dep	Accumulated Depreciation	($18,421,995)	($9,665,708)	($1,765,013)	($4,097,683)	($1,676,229)	($668,886)	($511,155)	($37,320)
co	Capital Contribution	($16,028,901)	($8,461,148)	($1,333,297)	($3,460,826)	($1,445,381)	($623,828)	($658,421)	($45,999)
	Total Net Plant	$281,015,996	$140,890,127	$25,637,352	$65,382,498	$28,763,809	$11,698,145	$8,048,136	$595,928
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$335,078,839	$98,398,444	$25,823,900	$99,821,387	$73,909,904	$34,044,737	$2,645,233	$435,235
	OM&A Expenses	$26,811,010	$15,330,739	$2,281,590	$4,666,734	$1,760,209	$565,020	$2,138,815	$67,901
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$361,889,849*	*$113,729,183*	*$28,105,490*	*$104,488,121*	*$75,670,114*	*$34,609,757*	*$4,784,048*	*$503,136*
	Working Capital	$54,283,477	$17,059,377	$4,215,823	$15,673,218	$11,350,517	$5,191,464	$717,607	$75,470
	Total Rate Base	$335,299,474	$157,949,505	$29,853,175	$81,055,716	$40,114,326	$16,889,609	$8,765,744	$671,399
		Rate Base Input equals Output							
	Equity Component of Rate Base	$134,119,789	$63,179,802	$11,941,270	$32,422,286	$16,045,731	$6,755,844	$3,506,297	$268,559
	Net Income on Allocated Assets	$13,295,730	$5,078,209	$3,453,364	($208,449)	$5,966,490	$1,275,723	($2,272,955)	$3,349
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$13,295,730	$5,078,209	$3,453,364	($208,449)	$5,966,490	$1,275,723	($2,272,955)	$3,349
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	95.63%	136.74%	76.68%	179.00%	132.74%	20.09%	83.98%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$0	($1,586,997)	$2,240,158	($3,302,363)	$4,605,246	$722,172	($2,653,390)	($24,825)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.91%	8.04%	28.92%	-0.64%	37.18%	18.88%	-64.82%	1.25%

EXHIBIT 8

RATE DESIGN

EXHIBIT 8

TAB 1

RATE DESIGN

RATE DESIGN OVERVIEW

The purpose of this Exhibit is to document and explain the rate design calculations performed by Hydro One Brampton to establish the proposed distribution rates, by rate class, for the 2011 Test Year.

Hydro One Brampton has determined its' total 2011 Test Year Service Revenue Requirement to be $66,581,754. The total revenue offsets of $3,986,411 reduce Hydro One Brampton's total service revenue requirement to a base revenue requirement of $62,595,343. This value also represents Hydro One Brampton's gross revenue for determining the proposed distribution rates.

The Base Revenue Requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in the Cost Allocation study. The following table illustrates how the base revenue has been allocated across the rate classes

Table 1: Rate Base Revenue Allocation

Customer Class	Total Revenue Requirement 2011 Cost Allocation	Proposed Revenue to Cost Ratio	2011 Proposed Service Revenue Requirement	2011 Proposed Miscellaneous Revenue per Cost Allocation Model	2011 Proposed Base Revenue Requirement
Residential	$ 37,305,911	102.50%	$ 36,375,334	$ 2,443,358	$ 33,931,976
GS <50	$ 7,942,305	117.50%	$ 6,988,859	$ 369,847	$ 6,619,012
GS>50-Regular	$ 9,858,387	80.00%	$ 10,957,305	$ 488,883	$ 10,468,422
GS 700 - 4,999	$ 8,578,688	131.26%	$ 7,604,334	$ 174,116	$ 7,430,218
Large Use >5MW	$ 2,157,987	100.00%	$ 2,223,328	$ 89,025	$ 2,134,304
Street Light	$ 622,203	70.00%	$ 2,297,705	$ 414,175	$ 1,883,530
USL	$ 116,274	90.00%	$ 134,890	$ 7,008	$ 127,882
Total	**$ 66,581,755**		**$ 66,581,755**	**$ 3,986,412**	**$ 62,595,343**

BASE REVENUE REQUIREMENT GIVEN PROPOSED REVENUE TO COST RATIOS

The first step of Rate Design is to establish the Base Revenue Requirement by customer class. The following table provides the change in Base Revenue Requirement by customer class at existing rates as compared to the proposed Base Revenue Requirement by customer class which reflects the proposed revenue to cost ratios

Table 2: Rate Base Revenue Movement

Customer Class	2011 Total Base Revenue with 2010 Rates	2011 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	2011 Proposed Base Revenue Requirement
Residential	$ 32,611,130	$ 34,862,553	$ 33,931,976
GS <50	$ 7,083,429	$ 7,572,458	$ 6,619,012
GS>50-Regular	$ 8,764,421	$ 9,369,504	$ 10,468,422
GS 700 - 4,999	$ 7,861,805	$ 8,404,573	$ 7,430,218
Large Use >5MW	$ 1,935,349	$ 2,068,962	$ 2,134,304
Street Light	$ 194,594	$ 208,028	$ 1,883,530
USL	$ 102,209	$ 109,266	$ 127,882
Total	**$ 58,552,937**	**$ 62,595,343**	**$ 62,595,343**

BASE REVENUE ALLOCATION PER RATE CLASS

Complete Rate Design Calculations can be viewed in Exhibit 11 Tab 1 Schedule 6

EXHIBIT 8

TAB 2

FIXED / VARIABLE PROPORTION

CURRENT AND PROPOSED PROPORTIONS

FIXED AND VARIABLE REVENUE ALLOCATION

The next step in the Rate Design process is to allocate the Base Revenue Requirement between Fixed and Variable Revenues. The purpose of this section is to describe the determination of the fixed and variable proportion by rate class, then to calculate the proposed fixed and variable distribution rates for the 2011 Test year.

Listed below is a chart that identifies Hydro One Brampton's current and proposed allocation of Service revenue allocated between the fixed and volumetric variables. .

Table 1: Current and Proposed Allocation of Service Revenue

Rate Class	Current Fixed Charge Split	Current Volumetric Charge Split	Proposed Fixed Charge Split	Proposed Volumetric Charge Split
Residential	47.7%	52.3%	47.7%	52.3%
GS <50	26.9%	73.1%	26.9%	73.1%
GS>50-Regular	21.6%	78.4%	21.6%	78.4%
GS 700 - 4,999	22.8%	77.2%	22.8%	77.2%
Large Use >5MW	17.6%	82.4%	17.6%	82.4%
Street Light	0.0%	100.0%	35.8%	64.2%
USL	14.7%	85.3%	14.7%	85.3%

HOBNI is proposing to maintain the same fixed/variable proportions that are currently in effect for all classes with the exception of the Street Light class. A fixed Monthly service charge has been designed and will be applied to the number of connections.

FIXED AND VARIABLE PROPORTION

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, the OEB addressed a number of "Other Rate Matters", including its treatment of the fixed component (the Monthly Service Charge, or "MSC") of the bill. On page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is

defined in the September 29, 2006 report of the OEB entitled "Cost Allocation: Board Direction on Cost Allocation Methodology for Electricity Distributors".

With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB's Rate Review proceeding (EB-2008-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time.

Table 2: Fixed/Variable Base Revenue Requirement Allocations by Customer Class

Customer Class	Total Base Revenue Requirement	Fixed Revenue Portion	2011 Fixed Revenue	Variable Revenue Portion	2011 Fixed Revenue
Residential	$ 33,931,976	47.7%	$ 16,181,359	52.3%	$ 17,750,617.49
GS <50	$ 6,619,012	26.9%	$ 1,783,387	73.1%	$ 4,835,625.58
GS>50-Regular	$ 10,468,422	21.6%	$ 2,259,505	78.4%	$ 8,208,917.13
GS 700 - 4,999	$ 7,430,218	22.8%	$ 1,694,711	77.2%	$ 5,735,506.63
Large Use >5MW	$ 2,134,304	17.6%	$ 374,951	82.4%	$ 1,759,352.55
Street Light	$ 1,883,530	35.8%	$ 674,744	64.2%	$ 1,208,785.51
USL	$ 127,882	14.7%	$ 18,757	85.3%	$ 109,124.55
Total	**$ 62,595,343**		**$ 22,987,414**		**$ 39,607,929**

PROPOSED FIXED CHARGES:

HOBNI currently has classes that are above and below the lower and upper bands respectively. As per the OEB's Rate Review proceeding (EB-2008-0031), HOBNI does not currently wish to make changes to the current Monthly Service Charge. HOBNI is concerned that in doing so, in conjunction with rate changes associated with cost allocation, customers will experience rate confusion.

Consistent with the Chapter 2 Filing Requirements issued on May 27, 2009, Hydro One Brampton has provided **Table 3** on the following page which compares the current and

proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study.

Table 3: Monthly Service Charge Analysis

Customer Class	2010 Fixed Rates From OEB Approved Tariff	Fixed Rate Based on no Cost Allocation Adjustment	Fixed Rate Based on Current Fixed/Variable Revenue Proportions	Proposed Fixed Rates	Customer Unit Cost per month Avoided Cost	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)
Residential	$ 10.48	$ 11.20	$ 10.91	$ 10.91	$ 4.19	$ 11.67
GS <50	$ 20.15	$ 21.54	$ 18.83	$ 18.83	$ 10.83	$ 21.25
GS>50-Regular	$ 101.56	$ 108.57	$ 121.31	$ 121.31	$ 55.36	$ 92.70
GS 700 - 4,999	$ 1,410.33	$ 1,507.70	$ 1,332.91	$ 1,332.91	$ 78.24	$ 367.71
Large Use >5MW	$ 4,722.21	$ 5,048.22	$ 5,207.66	$ 5,207.66	-$ 489.05	-$ 183.05
Street Light		$ -	$ -	$ 1.34	$ 3.43	$ 12.27
USL	$ 20.15	$ 21.54	$ -	$ 1.21	$ 0.60	$ 4.82

As can be seen in **Table 3** above, some of the proposed rates are below the Ceiling Fixed Monthly Service Charge per the Cost Allocation model, while others are greater than the Ceiling Fixed Monthly Service Charge. In the case of the Ceiling Monthly Service Charge for the Large User Class the Ceiling Fixed Monthly Service Charge is a negative value, this is illogical, but can be attributable to the way the Cost Allocation model allocates the Late Payment Charge Miscellaneous Revenues. This allocation is an anomaly and the Ceiling Monthly Service Charge calculated in the Cost Allocation model is not a representative value.

All changes in Monthly Service Charges are due solely to changes in the total base revenue requirement in conjunction with adjustments associated with the proposed cost allocation adjustments attributable to each customer class. Below, **Table 4** provides HOBNI's calculations of its proposed monthly fixed distribution charges for the 2011 Test Year assuming the fixed/variable split supporting the current approved rates

Table 4: Proposed Monthly Fixed Distribution Charges

Customer Class	Total Base Revenue Requirement	Fixed Revenue Portion	2011 Fixed Revenue	2011 Customers / Connections	Annualized 2011 Customers / Connections	Proposed Fixed Distribution Rates
Residential	$ 33,931,976	47.7%	$ 16,181,359	123,660	1,483,920	$ 10.91
GS <50	$ 6,619,012	26.9%	$ 1,783,387	7,893	94,715	$ 18.83
GS>50-Regular	$ 10,468,422	21.6%	$ 2,259,505	1,552	18,627	$ 121.31
GS 700 - 4,999	$ 7,430,218	22.8%	$ 1,694,711	106	1,271	$ 1,332.91
Large Use >5MW	$ 2,134,304	17.6%	$ 374,951	6	72	$ 5,207.66
Street Light	$ 1,883,530	35.8%	$ 674,744	42,158	505,899	$ 1.34
USL	$ 127,882	14.7%	$ 18,757	1,300	15,600	$ 1.21
Total	**$ 62,595,343**		**$ 22,987,414**			

PROPOSED VOLUMETRIC CHARGES:

The next step in the Rate Design Process is to establish the volumetric rate based on the allocated variable Base Revenue Requirement plus the forecast Transformer Ownership Allowance for the customer classes that will be entitled to this credit. Once the gross variable revenues, before the credit for Transformer Allowance are established, the rates associated with the volumetric components for the 2011 Test Year can be derived. The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement plus the transformer allowance amount, for each class, by the appropriate 2011 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides HOBNI's calculations of its proposed variable distribution charges for the 2011 Test Year based on utilizing the proposed fixed/variable split as described above. Please note that these proposed rates exclude the proposed Transformer Allowance.

Table 5: Proposed Variable Distribution Charges 2010

Customer Class	A Total Base Revenue Requirement	B 2011 Fixed Revenue	C = A - B 2011 Variable Revenue (Net)	D 2011 Transformer Allowance	E = C + D 2011 Variable Revenue (Gross)	F 2011 Billing Determinants	Metrics	G = E / F Proposed Variable Distribution Rates
Residential	$ 33,931,976	$ 16,189,564	$ 17,742,413		$ 17,742,413	1,107,769,581	kWh	$ 0.0160
GS <50	$ 6,619,012	$ 1,783,492	$ 4,835,520		$ 4,835,520	290,725,436	kWh	$ 0.0166
GS>50-Regular	$ 10,468,422	$ 2,259,588	$ 8,208,834	$ 189,813	$ 8,398,647	3,079,920	kW	$ 2.7269
GS 700 - 4,999	$ 7,430,218	$ 1,694,714	$ 5,735,503	$ 1,384,095	$ 7,119,599	1,879,169	kW	$ 3.7887
Large Use >5MW	$ 2,134,304	$ 374,952	$ 1,759,352		$ 1,759,352	697,451	kW	$ 2.5225
Street Light	$ 1,883,530	$ 677,904	$ 1,205,625		$ 1,205,625	88,637	kW	$ 13.6018
USL	$ 127,882	$ 18,882	$ 109,000		$ 109,000	4,899,876	kWh	$ 0.0222
Total	**$ 62,595,343**	**$ 22,999,095**	**$ 39,596,248**	**$ 1,573,908**	**$ 41,170,156**			

SUMMARY OF PROPOSED DISTRIBUTION RATES:

Table 6: Proposed 2011 Electricity Distribution Rates (excluding proposed rate riders and rate adders)

Customer Class	Proposed Fixed Distribution Rates		Proposed Volumetric Rates		Transformer Allowance
	Customer	Connection	kWh	kW	kW
Residential	$ 10.91	-	$ 0.0160	-	-
GS <50	$ 18.83	-	$ 0.0166	-	-
GS>50-Regular	$ 121.31	-	-	$ 2.7269	-$ 0.7202
GS 700 - 4,999	$ 1,332.91	-	-	$ 3.7887	-$ 0.8952
Large Use >5MW	$ 5,207.66	-	-	$ 2.5225	-
Street Light	-	$ 1.34	-	$ 13.6018	-
USL	-	$ 1.21	$ 0.0222	-	-

EXHIBIT 8

TAB 3

RETAIL TRANSMISSION SERVICE RATES

RETAIL TRANSMISSION SERVICE RATES OVERVIEW

RETAIL TRANSMISSION SERVICE RATES

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e., deferral accounts 1584 and 1586).

On July 22, 2009 the Board issued an amended "Guideline for Electricity Distribution Retail Transmission Service Rates" ("RTSR Guideline"), which provided electricity distributors with instructions on the evidence needed, and the process to be used, to adjust RTSRs to reflect the changes in the UTRs effective July 1, 2009.

On January 21, 2010, the Board approved new UTRs effective January 1, 2010. The new UTRs were as follows:

- Network Service Rate has increased from $2.66 to $2.97 per kW per month.
- Line Connection Service Rate has increased from $0.70 to $0.73 per kW per month.
- Transformation Connection Service Rate has increased from $1.57 to $1.71 per kW per month.

On November 6th, 2009, HOBNI submitted its 2010 Distribution Rate Adjustments in accordance with the July 22, 2009 RSTR Guideline to the OEB for approval. The rate adjustments incorporated the above mentioned UTR's. On April 13, 2010, HOBNI received rate approval from the OEB for its proposed changes to its RTSR's. These rates are currently in effect.

At the time of this rate application, HOBNI is not aware of any proposed changes to the current UTR's. As a result, HOBNI has not revised any of its RTSR's at this time. As HOBNI is currently seeking a January 1, 2011 implementation date, it requests that it be permitted to revise its 2011 RTSR's accordingly, should additional information pertaining to UTR's become available. Until that time HOBNI ask for approval the continuance of the previously approved RTSR's.

Retail Transmission Service Rates Calculation

On April 13, 2010, under OEB decision and order EB-2009-0199, the Board directed Hydro One Brampton to reflect the January 1, 2010 UTRs in accordance with the July 22, 2009 RSTR Guideline. This represented an increase of about 15.6% to the RTSR Network Service Rates, and an increase of 5.2% to the RSTR Line and Transformation Connection Service Rates. This increase was reflected in Hydro One Brampton's 2010 Rate Order **Table 1** below identifies Hydro One Brampton's currently approved RTSR's.

Table 1: Approved Retail Transmission Network, Line, and Service Connection

Rates effective May 1, 2010			
Rate Class	**Metric**	**RTSR - Network**	**RTSR - Connection**
Residential	$/kWh	0.0061	0.0051
General Service < 50	$/kWh	0.0055	0.0044
General Service > 50	$/kW	2.1307	1.6973
Intermediate	$/kW	2.3896	1.8245
Large Use	$/kW	2.7045	2.1088
Unmeted Scattered Load	$/kWh	0.0055	0.0044
Sentinel Lighting	$/kW	1.7764	1.4148
Street Lighting	$/kW	1.7741	1.4130

HISTORICAL TRENDING

Hydro One Brampton has included an analysis of the past three historical years, detailing variance account activity.

Table 2: Accounts 1586 – RSVA Transmission Connection Charge Account

Month	2007 Actuals	2008 Actuals	2009 Actuals
Opening Balance	142,192.19	- 265,127.84	-1,400,192.17
January	- 90,881.42	- 292,440.04	- 154,453.12
February	- 5,011.25	- 101,266.35	138,012.81
March	-285,985.81	- 264,093.87	- 19,661.58
April	54,693.73	- 206,141.59	- 85,306.72
May	73,903.14	- 119,657.98	- 152,822.21
June	129,238.62	48,874.78	236,250.52
July	120,572.67	115,000.83	- 194,838.03
August	- 4,279.34	- 66,585.12	41,687.04
September	178,826.31	94,785.96	- 123,072.39
October	-173,877.42	- 95,663.93	- 128,767.09
November	- 57,553.88	- 118,010.37	- 171,889.42
December	-346,965.38	- 129,866.65	- 95,880.22
Annual Activity	-407,320.03	-1,135,064.33	- 710,740.41
Closing Balanc	**-265,127.84**	**-1,400,192.17**	**-2,110,932.58**

Table 3: Account 1584 – RSVA Transmission Network Charges Account

Month	2007 Actuals	2008 Actuals	2009 Actuals
Opening Balance	876,851.09	969,994.08	- 495,730.41
January	- 22,580.48	- 572,062.79	- 135,512.44
February	- 265,472.85	- 265,306.23	345,758.87
March	75,753.38	- 402,553.06	83,342.97
April	- 140,896.52	- 361,121.10	34,597.86
May	57,243.32	- 86,041.15	- 215,844.05
June	161,745.30	74,486.48	231,710.39
July	221,663.49	180,587.84	- 4,098.76
August	- 61,053.19	- 48,351.22	98,235.22
September	231,155.61	173,435.05	- 52,913.54
October	- 200,647.22	- 12,246.67	164,681.15
November	- 447,295.06	- 94,463.78	17,090.76
December	483,527.21	- 52,087.86	78,640.71
Annual Activity	93,142.99	- 1,465,724.49	645,689.14
Closing Balance	969,994.08	- 495,730.41	149,958.73

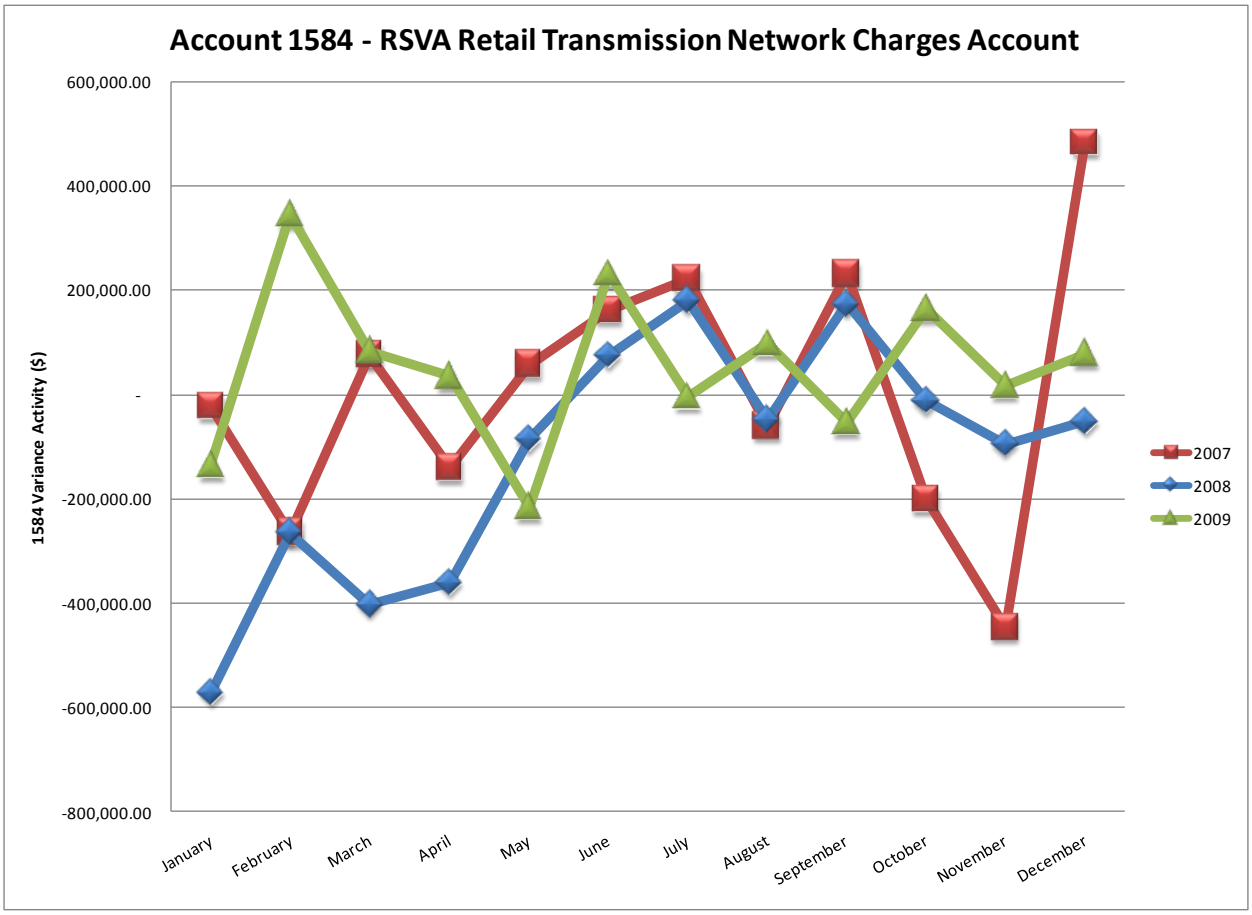


Figure 1: Account 1584 – RSVA Retails Transmission Network Charges Account 1007, 2008, and 2009

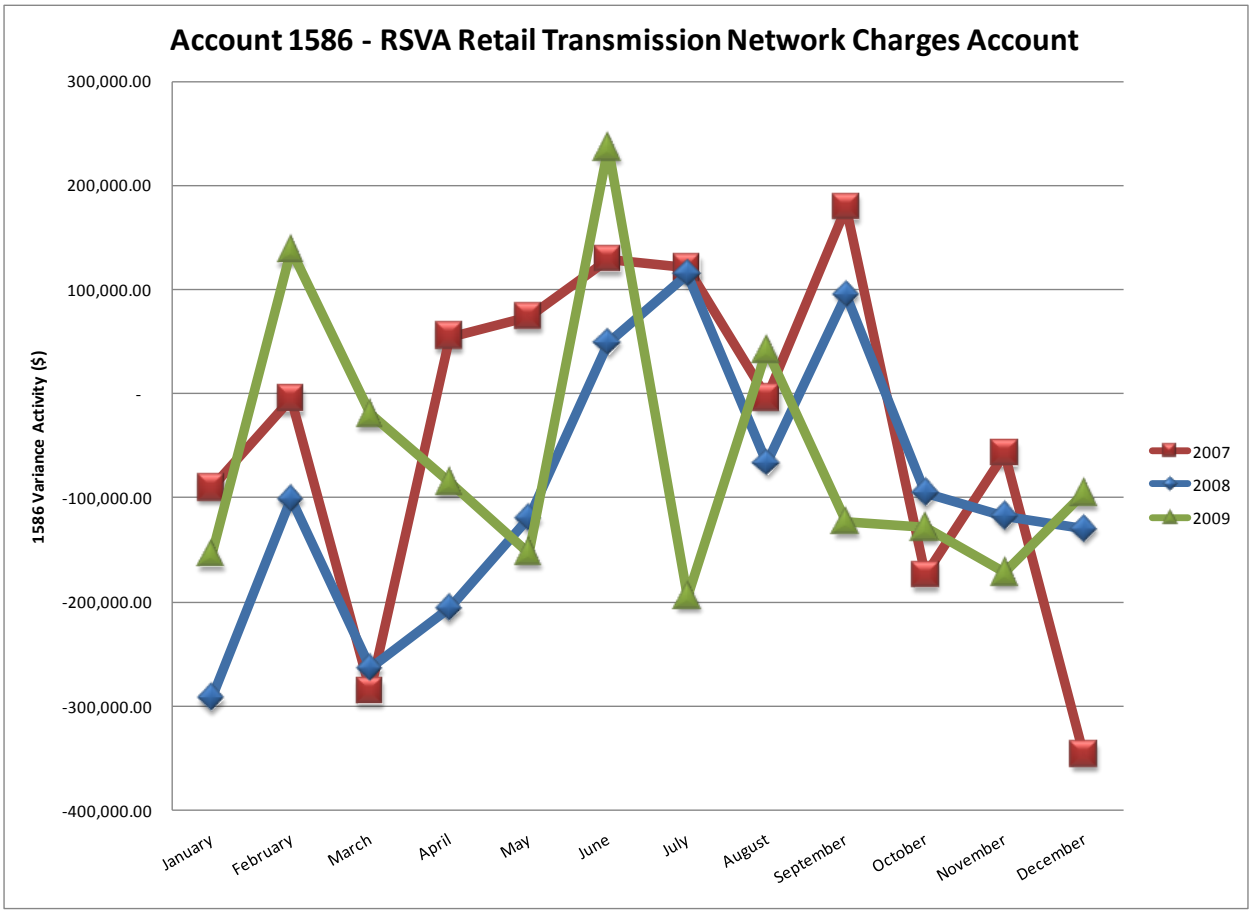


Figure 2: Account 1586 – RSVA Retails Transmission Network Charges Account 2007, 2008, and 2009

EXHIBIT 8

TAB 4

LOW VOLTAGE CHARGES

LOW VOLTAGE CHARGES OVERVIEW

In the Board's Decision and Order, EB-2009-0199, effective May 1, 2010, Hydro One Brampton was directed to book $219,087 as a revenue offset to amounts billed from Hydro One for Low Voltage Charges ("LV") included in account 1550, collected in rates for the period May 1, 2006 to December 31, 2009. This amounts to an approximate annual recovery of $60,000 which is significantly below Hydro One Brampton's current materiality threshold of $300,000.

In response to the Board Staff Submission dated February 9, 2010, Hydro One Brampton identified that the calculated Low Voltage Rate Adders were so minimal that in some cases they did not impact Distribution Volumetric Rates. Column D in **Table 1** below, as determined in the 2006 EDR Rate Application, is not rounded to the same degree of precision as the Distribution Volumetric Rates per unit. Since Distribution Volumetric Rates are rounded to four decimal places, any amount applied to account 1550 should also be rounded to the same degree of precision, as shown in Column C of **Table 1**. As a result, LV Adjustment Revenue was not recognized for Residential or Small General Service rate classes.

Table 1: Impact on Volumetric Distribution Rates Due to LV Charges

		A	B	C	D
Rate Class	Billing Quantity	Distribution Volumetric Rate - Excl LV Adj.	Distribution Volumetric Rate - Incl LV Adj.	Difference in Rates Due to LV Charges Adjustment	LV Charges Adjustment Calculated in 2006 EDR
RESIDENTIAL	per kWh	0.0158	0.0158	-	0.00002847
GENERAL SERVICE Less than 50 kW	per kWh	0.0182	0.0182	-	0.00002656
GENERAL SERVICE Other > 50 kW (specify) . 50 kW to 699 kW	per kW	2.3404	2.3508	0.0104	0.01040880
GENERAL SERVICE Other > 50 kW (specify) .700 kW to 4999 kW	per kW	3.8167	3.8288	0.0121	0.01208561
GENERAL SERVICE Large Use (> 5000 kW)	per kW	2.9602	2.9747	0.0145	0.01448395
GENERAL SERVICE Unmetered Scattered Load	per kWh	0.0182	0.0182	-	-
SENTINEL LIGHTING	per kW	3.8848	3.8936	0.0088	0.00874543
STREET LIGHTING	per kW	2.2507	2.2596	0.0089	0.00886149

Column H, in **Table 2** below, calculates the amount that would be correctly applied to determine the annual amount of offset to account 1550. The product of incremental LV Charges component of rates in Column E, **Table 2** below, (brought forward from Column C of **Table 1**) multiplied by the billing determinants used in the 2006 EDR computes a total annual amount of $58,993.

Table 2: LV Charges Recovered Through Rate Rider

		E=C	F	G	H = F X E or G X E
Rate Class	**Billing Quantity**	**Difference in Rates Due to LV Charges Adjustment**	**kWh Determinants - 2006 EDR**	**kW Determinants - 2006 EDR**	**LV Costs Recovered**
RESIDENTIAL	per kWh	-	989,558,788	-	-
GENERAL SERVICE Less than 50 kW	per kWh	-	276,748,729	-	-
GENERAL SERVICE Other > 50 kW (specify) . 50 kW to 699 kW	per kW	0.0104	1,018,101,225	2,771,782	28,827
GENERAL SERVICE Other > 50 kW (specify) .700 kW to 4999 kW	per kW	0.0121	827,789,524	1,918,198	23,210
GENERAL SERVICE Large Use (> 5000 kW)	per kW	0.0145	244,039,963	443,840	6,436
GENERAL SERVICE Unmetered Scattered Load	per kWh	-	-	-	-
SENTINEL LIGHTING	per kW	0.0088	80,647	233	2
STREET LIGHTING	per kW	0.0089	19,634,754	58,210	518
					58,993

Table 3 below calculates the annual LV Recovery collected through rates.

Table 3: LV Recovery

	GDP-IPI - X	LV Costs Recovered May 1 2006 to April 30 2007	LV Costs Recovered May 1 2007 to April 30 2008	LV Costs Recovered May 1 2008 to April 30 2009	LV Costs Recovered May 1 2009 to Apr 30 2010
LV Charges Recovered May 1 2006 to April 30 2007		58,993			
IPI-X for May 1 2007 to April 30 2008	0.92%				
LV Charges Recovered May 1 2007 to April 30 2008			59,536		
IPI-X for May 1 2008 to April 30 2009	0.90%				
LV Charges Recovered May 1 2008 to April 30 2009				60,072	
IPI-X for May 1 2009 to Dec 31 2009	1.10%				
LV Charges Recovered May 1 2009 to April 30 2010					60,732

Table 4 below details the annual amounts billed from Hydro One for LV included in account 1550.

Table 4: Hydro One LV Charges

LV Charges	2007	2008	2009	2010
JAN	10,609.20	13,471.51	-	3,100.00
FEB	14,064.75	10,830.63	1.04	2,889.27
MAR	10,463.04	10,610.98	-	3,193.12
APR	10,427.13	12,318.81	-	
MAY	10,650.25	10,074.20	-	
JUN	11,799.12	11,311.08	4,959.67	
JUL	12,109.92	12,897.38	-	
AUG	12,497.32	-	-	
SEP	13,203.11	-	2,260.62	
OCT	12,734.69	-	118.27	
NOV	13,865.23	-	118.27	
DEC	10,226.12	-	5,560.07	
TOTAL	**142,649.88**	**81,514.59**	**13,017.94**	**9,182.39**

As volumes relating to Hydro One Brampton's charges from Hydro One for LV are minimal and fluctuations continue year over year, Hydro One Brampton is proposing to remove Low Voltage Rate Adders from the Distribution Volumetric Rate calculation and offsetting the charges from Hydro One (for LV) directly to account 1550. Disposition of account 1550 would then take place annually during the IRM process, assuming the sum of the Group 1 accounts meets the annual disposition threshold of $.001/kWh (credit or debit), as outlined in the Report on the Board on Electricity Distributor's Deferral and Variance Account Review ("EDDVAR") (EB-2008-0046), dated July 31, 2009.

LOW VOLTAGE RATE ADDER CALCULATION

Hydro One Brampton is proposing the removal of Low Voltage Rate Adders from the Distribution Volumetric Rate Calculation and offsetting the charges from Hydro One (for LV) directly to account 1550.

EXHIBIT 8

TAB 5

LOSS ADJUSTMENT FACTORS

LOSS ADJUSTMENT FACTORS OVERVIEW

Through the provision of electricity distribution services, the total volume of electricity delivered to customers will invariably be lower than the total volume of electricity the distributor is supplied at its connection points to the provincial transmission grid. The differences in volumes are known as “line losses” or simply “losses”. Losses can be technical in nature, such as the conversion of electricity to heat energy at various system components such as conductors and transformers. Losses can also be non-technical in nature occurring from theft of power, metering errors, billing errors and inaccurate proxies of unmetered loads. Losses are also categorized based on where they occur. Those originating within the utility’s distribution system are known as distribution system losses and those upstream or attributable to the facility prior to entering the utility’s distribution system are known as supply facility losses. Loss factors are calculated to approximate these volumes of losses – a distribution system loss factor (DLF) and a supply facility loss factor (SFLF). The product of these two factors is known as the total loss factor (TLF). The TLF is applied to customers’ metered consumption or proxy unmetered usage for billing purposes to determine the billed consumption that reflects the volume of electricity supplied or purchased by HOBNI to meet customers’ requirements given that some volumes will be lost due to the factors previously outlined

Hydro One Brampton is entirely supplied from delivery points on the transmission system, and consequently purchases its electricity through the Independent Electricity System Operator (the “IESO”) administered markets with one exception. HOBNI does have one 44 kV distribution line that is owned by Hydro One Networks Inc., and in this respect, HOBNI is considered to be an embedded LDC for this single feeder. The commodity associated with this supply point is also settled via the IESO.

HOBNI has calculated its historical DLF to be 1.0324, a SFLF of 1.0025, a TLF of 1.0349. In addition, HOBNI is also proposing to continue with the approved loss adjustment factor for primary metered large use customers of 1.0045. These calculations are based on methodology 5 outlined in section 2.9.4, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued by the Board on May 27, 2009.

Table 1: Loss Factor Calculation

		Year 1	Year 2	Year 3	Year 4	Year 5	5 Year Average
	Losses in Distributor's System						
A1	"Wholesale" kWh delivered to distributor (uplifted)	3,848,828,345	3,854,274,114	3,958,591,768	3,915,443,564	3,727,941,968	3,861,015,952
A2	"Wholesale" kWh delivered to distributor (non uplifted)	3,839,496,574	3,849,466,656	3,948,241,783	3,903,343,497	3,716,501,580	3,851,410,018
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)	308,575,243	340,889,348	359,937,344	392,283,776	346,811,250	349,699,392
C	Net "Wholesale" kWh delivered to distributor (A2)-(B)	3,530,921,331	3,508,577,308	3,588,304,439	3,511,059,721	3,369,690,330	3,501,710,626
D	"Retail" kWh delivered by distributor	3,723,506,554	3,718,723,113	3,839,000,000	3,791,763,566	3,611,622,564	3,736,923,159
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	304,422,360	334,087,722	355,306,260	388,700,963	342,523,390	345,008,139
F	Net "Retail" kWh delivered by distributor (D)-(E)	3,419,084,194	3,384,635,391	3,483,693,740	3,403,062,603	3,269,099,174	3,391,915,021
G	Loss Factor in distributors system [(C)/(F)]	1.0327	1.0366	1.0300	1.0317	1.0308	1.0324
	Losses Upstream of Distributors System						
H	Supply Facility Loss Factor (A1)/(A2)	1.0024	1.0012	1.0026	1.0031	1.0031	1.0025
	Total Losses						
I	**Total Loss Factor [(G)*(H)]**	**1.0352**	**1.0379**	**1.0327**	**1.0349**	**1.0339**	**1.0349**

HOBNI has calculated an historical SFLF based on actual kWH purchased from the IESO. The calculation was completed by determining the ratio of the kWH purchased uplifted to the kWH purchased non-uplifted. As illustrated in **Table 1** above, the result is a SFLF of 1.0025.

Listed below is a chart that identifies HOBNI's proposed loss factors. It should be noted that HOBNI is proposing to maintain the currently approved loss factors for Large Users. These loss factors are 1.0045 and 1.0145 for Large Users primary and secondary metered respectively.

HOBNI has calculated a SFLF of 1.0025. Large Users are not connected directly to the supply facility. They are connected to the supply facility via distribution lines. As a result, they do incur some distribution losses. HOBNI does not recommend applying the SFLF to the Large User class, but recommends keeping the original loss factors active as they will account for some additional line losses.

Table 2: Loss Factors

Loss Factors	
Supply Facilities Loss Factor	**1.0025**
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	**1.0324**
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	**1.0100**
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	**1.0221**
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	**1.0000**
Total Loss Factor - Secondary Metered Customer < 5,000 kW	**1.0349**
Total Loss Factor - Secondary Metered Customer > 5,000 kW	**1.0145**
Total Loss Factor - Primary Metered Customer < 5,000 kW	**1.0247**
Total Loss Factor - Primary Metered Customer > 5,000 kW	**1.0045**

A brief description of each rate class is provided below.

Residential

This classification refers to an account where electricity is delivered at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation.

Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruple house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

GS < 50 KW

This classification refers to a non residential account where electricity is delivered at 750 volts or less whose monthly average peak demand is less than, or forecast to be less than, 50 kW.

GS > 50 KW

This classification refers to a non residential account whose monthly average peak demand is greater than, or is forecast to be greater than, 50 kW but less than 700 kW.

Intermediate (GS 700 – 4,999KW)

This classification refers to a non residential account whose monthly average peak demand is greater than, or is forecast to be greater than, 700 kW but less than 4,999 kW.

Large Use

This classification refers to a non residential account whose monthly average peak demand is greater than, or is forecast to be greater than 5,000 kW.

Unmetered Scattered Load (USL)

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

Standby Power

Standby Charges are charges imposed by a distributor on a customer with load displacement facilities behind its meter to address the fact that the customer is dependent on the distributor for its entire electricity supply when the load displacement facility is out of service. The distributor must be appropriately compensated for maintaining the ability to accommodate the total load of a customer at any time.

Sentinel Lighting

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

Street Lighting

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micorFIT program and connected to the distributor's distribution system.

LOSS FACTORS

Hydro One Brampton is entirely supplied from delivery points on the transmission system, and consequently purchases its electricity through the Independent Electricity System Operator (the "IESO") administered markets with one exception. One of HOBNI's supply points is a 44 kV distribution line that emanates from a Hydro One Networks Inc. ("HONI") transformer station, and in this respect, HOBNI is considered to be an embedded LDC for this single feeder.

TOTAL LOSS FACTOR

HOBNI has calculated the total loss factor to be applied to customers' consumption based on the weighted average wholesale and retail kWh for the five historical years 2005 to 2009. As a result of the analysis HOBNI is proposing the Total Loss Factor (the "TLF") for 2010 be set at 1.0349 for secondary metered customers < 5,000 kW. This is a decrease from the current Board Approved TLF of 1.0356. The calculations are summarized in **Table 1** on the following page.

Table 1: Loss Factor Calculations

			2005	2006	2007	2008	2009	5 Year Weighted Average
Losses in Distributor's System								
A_1	"Wholesale" kWh delivered to distributor (uplifted)		3,848,828,345	3,854,274,114	3,958,591,768	3,915,443,564	3,727,941,968	19,305,079,759
A_2	"Wholesale" kWh delivered to distributor (non uplifted)		3,839,496,574	3,849,466,656	3,948,241,783	3,903,343,497	3,716,501,580	19,257,050,090
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer		308,575,243	340,889,348	359,937,344	392,283,776	346,811,250	1,748,496,961
C	Net "Wholesale" kWh delivered to distributor	**A_2-B**	**3,530,921,331**	**3,508,577,308**	**3,588,304,439**	**3,511,059,721**	**3,369,690,330**	**17,508,553,129**
D	"Retail" kWh delivered by distributor		3,723,506,554	3,718,723,113	3,839,000,000	3,791,763,566	3,611,622,564	18,684,615,797
E	Portion of "Retail" kWh delivered for Large Use Customer		304,422,360	334,087,722	355,306,260	388,700,963	342,523,390	1,725,040,694
F	Net "Retail" kWh delivered by distributor	**D-E**	**3,419,084,194**	**3,384,635,391**	**3,483,693,740**	**3,403,062,603**	**3,269,099,174**	**16,959,575,103**
G	Loss Factor in distributors system	**C/F**	**1.0327**	**1.0366**	**1.0300**	**1.0317**	**1.0308**	**1.0324**
Losses Upstream of Distributor's System								
H	Supply Facility Loss Factor	**A_1/A_2**	**1.0024**	**1.0012**	**1.0026**	**1.0031**	**1.0031**	**1.0025**
Total Losses								
I	Total Loss Factor	**GxH**	**1.0352**	**1.0379**	**1.0327**	**1.0349**	**1.0339**	**1.0349**

SUPPLY FACILITY LOSS FACTOR:

The Supply Facility Loss Factor (the "SFLF") is calculated in **Table 1**(previous page) and represents the losses on supply to HOBNI. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF is used in the calculations of the total loss factor above. The SFLF weighted average for the five historical years 2005 to 2009 is 1.0025.

MATERIALITY ANALYSIS ON DISTRIBUTION LOSSES:

HOBNI's proposed TLF is 3.49% for secondary metered customers < 5,000 kW. Pursuant to the Filing Requirements for Transmission and Distribution Applications, dated May 27, 2009, the TLF is less than 5%, Hydro One Brampton is not required to provide an explanation of, or justification for, its loss adjustment factor.

Summary of the Supply Facility Loss Factors, Distribution Loss Factors and Total Loss Factors are provided below. Hydro One Brampton applies the TLF to the corresponding customer classes as identified below.

Table 2: Loss Factors Summary

Loss Factors	
Supply Facilities Loss Factor	**1.0025**
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	**1.0324**
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	**1.0100**
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	**1.0221**
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	**1.0000**
Total Loss Factor - Secondary Metered Customer < 5,000 kW	**1.0349**
Total Loss Factor - Secondary Metered Customer > 5,000 kW	**1.0145**
Total Loss Factor - Primary Metered Customer < 5,000 kW	**1.0247**
Total Loss Factor - Primary Metered Customer > 5,000 kW	**1.0045**

EXHIBIT 8

TAB 6

RATE SCHEDULE AND BILL IMPACTS

BILL IMPACTS OVERVIEW

The following tables identify Hydro One Brampton's proposed 2011 electricity distribution rate impacts for each of its customer classes. These cost impacts are based on the assumption that all of the proposed rate adders and rate riders are approved as proposed in this application. These include the following:

- Smart Meter Rate Rider of $0.36 per month per metered customer
- Smart Meter Rate Adder of $1.03 per month per metered customer
- Late Payment Rate Rider of $0.28 per month per customer
- Volumetric Rate Rider for the disposition of Group 2 Regulatory Asset Accounts
- Volumetric Rate Rider associated with LRAM and SSM
- The continuation of previous Riders associated with Hydro One Brampton's 2010 Rate Application

A complete schedule of 2011 Proposed Tariff of Rates and Charges including Specific Service Charges, Allowances and Loss Factors is filed as Exhibit 1, Tab 1, Schedule 4.

BILL IMPACT TABLE

Table 1: Residential Bill Impacts

Consumption	**100**	**kWh**	***Loss Factor Old***			**1.0356**			
RPP Tier One	**600**	**kWh**	***Loss Factor New***			**1.0349**			
Residential	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	104	0.0650	6.73	103	0.0650	6.73	0.00	0.0%	25.11%
Energy Second Tier (kWh)	0	0.0750	0.00	0	0.0750	0.00	0.00	0.0%	0.00%
Sub-Total: Energy			**6.73**			**6.73**	**0.00**	**0.0%**	**25.11%**
Service Charge	1	10.60	10.60	1	11.27	11.27	0.67	6.3%	42.05%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	3.84%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	1.04%
Distribution Volumetric Rate	100	0.0154	1.54	100	0.0160	1.60	0.06	3.9%	5.97%
Distribution Volumetric Rate Rider (2011) Group 2	104	0.0000	0.00	103	0.0010	0.10	0.10	0.0%	0.37%
LRAM Volumetric Rate Rider (2011)	100	0.0000	0.00	100	0.0010	0.10	0.10	0.0%	0.37%
Distribution Volumetric Rate Rider (2010) Group 1	104	-0.0020	-0.21	103	-0.0020	-0.21	0.00	0.0%	-0.78%
Total: Distribution			**12.93**			**14.17**	**1.24**	**9.6%**	**52.87%**
Retail Transmission Rate – Network Service Rate	104	0.0061	0.63	103	0.0061	0.63	0.00	0.0%	2.35%
Retail Transmission Rate – Line and Transformation Connection	104	0.0051	0.53	103	0.0051	0.53	0.00	0.0%	1.98%
Retail Transmission Rate – Low Voltage Volumetric Rate	104	0.0000	0.00	103	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**1.16**			**1.16**	**0.00**	**0.0%**	**4.33%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**14.09**			**15.33**	**1.24**	**8.8%**	**57.20%**
Wholesale Market Service Rate	104	0.0056	0.58	103	0.0056	0.58	0.00	0.0%	2.16%
Rural Rate Protection Charge	104	0.0013	0.13	103	0.0013	0.13	0.00	0.0%	0.49%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.93%
Sub-Total: Regulatory			**0.96**			**0.96**	**0.00**	**0.0%**	**3.58%**
Debt Retirement Charge (DRC)	100	0.0070	**0.70**	100	0.0070	**0.70**	**0.00**	**0.0%**	**2.61%**
Total Bill before Taxes			**22.48**			**23.72**	**1.24**	**5.5%**	**88.51%**
GST	22.48	13%	**2.92**	23.72	13%	**3.08**	**0.16**	**5.5%**	**11.49%**
Total Bill			**25.40**			**26.80**	**1.40**	**5.5%**	**100.00%**

Table 2: Residential Bill Impacts

Consumption	**250**	**kWh**	***Loss Factor Old***			**1.0356**			
RPP Tier One	**600**	**kWh**	***Loss Factor New***			**1.0349**			
Residential	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	259	0.0650	16.83	259	0.0650	16.82	-0.01	(0.1)%	37.14%
Energy Second Tier (kWh)	0	0.0750	0.00	0	0.0750	0.00	0.00	0.0%	0.00%
Sub-Total: Energy			**16.83**			**16.82**	**-0.01**	**(0.1)%**	**37.14%**
Service Charge	1	10.60	10.60	1	11.27	11.27	0.67	6.3%	24.88%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	2.27%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.62%
Distribution Volumetric Rate	250	0.0154	3.85	250	0.0160	4.00	0.15	3.9%	8.83%
Distribution Volumetric Rate Rider (2011) Group 2	259	0.0000	0.00	259	0.0010	0.26	0.26	0.0%	0.57%
LRAM Volumetric Rate Rider (2011)	250	0.0000	0.00	250	0.0010	0.25	0.25	0.0%	0.55%
Distribution Volumetric Rate Rider (2010) Group 1	259	-0.0020	-0.52	259	-0.0020	-0.52	0.00	0.0%	-1.15%
Total: Distribution			**14.93**			**16.57**	**1.64**	**11.0%**	**36.59%**
Retail Transmission Rate – Network Service Rate	259	0.0061	1.58	259	0.0061	1.58	0.00	0.0%	3.49%
Retail Transmission Rate – Line and Transformation Connection	259	0.0051	1.32	259	0.0051	1.32	0.00	0.0%	2.91%
Retail Transmission Rate – Low Voltage Volumetric Rate	259	0.0000	0.00	259	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**2.90**			**2.90**	**0.00**	**0.0%**	**6.40%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**17.83**			**19.47**	**1.64**	**9.2%**	**42.99%**
Wholesale Market Service Rate	259	0.0056	1.45	259	0.0056	1.45	0.00	0.0%	3.20%
Rural Rate Protection Charge	259	0.0013	0.34	259	0.0013	0.34	0.00	0.0%	0.75%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.55%
Sub-Total: Regulatory			**2.04**			**2.04**	**0.00**	**0.0%**	**4.50%**
Debt Retirement Charge (DRC)	250	0.0070	**1.75**	250	0.0070	**1.75**	**0.00**	**0.0%**	**3.86%**
Total Bill before Taxes			**38.45**			**40.08**	**1.63**	**4.2%**	**88.50%**
GST	38.45	13%	**5.00**	40.08	13%	**5.21**	**0.21**	**4.2%**	**11.50%**
Total Bill			**43.45**			**45.29**	**1.84**	**4.2%**	**100.00%**

Table 3: Residential Bill Impacts

Consumption	500	kWh	*Loss Factor Old*			1.0356			
RPP Tier One	600	kWh	*Loss Factor New*			1.0349			
Residential	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	518	0.0650	33.66	517	0.0650	33.63	-0.03	(0.1)%	44.21%
Energy Second Tier (kWh)	0	0.0750	0.00	0	0.0750	0.00	0.00	0.0%	0.00%
Sub-Total: Energy			**33.66**			**33.63**	**-0.03**	**(0.1)%**	**44.21%**
Service Charge	1	10.60	10.60	1	11.27	11.27	0.67	6.3%	14.82%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	1.35%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.37%
Distribution Volumetric Rate	500	0.0154	7.70	500	0.0160	8.00	0.30	3.9%	10.52%
Distribution Volumetric Rate Rider (2011) Group 2	518	0.0000	0.00	517	0.0010	0.52	0.52	0.0%	0.68%
LRAM Volumetric Rate Rider (2011)	500	0.0000	0.00	500	0.0010	0.50	0.50	0.0%	0.66%
Distribution Volumetric Rate Rider (2010) Group 1	518	-0.0020	-1.04	517	-0.0020	-1.03	0.01	(1.0)%	-1.35%
Total: Distribution			**18.26**			**20.57**	**2.31**	**12.7%**	**27.04%**
Retail Transmission Rate – Network Service Rate	518	0.0061	3.16	517	0.0061	3.16	0.00	0.0%	4.15%
Retail Transmission Rate – Line and Transformation Connection	518	0.0051	2.64	517	0.0051	2.64	0.00	0.0%	3.47%
Retail Transmission Rate – Low Voltage Volumetric Rate	518	0.0000	0.00	517	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**5.80**			**5.80**	**0.00**	**0.0%**	**7.62%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**24.06**			**26.37**	**2.31**	**9.6%**	**34.67%**
Wholesale Market Service Rate	518	0.0056	2.90	517	0.0056	2.90	0.00	0.0%	3.81%
Rural Rate Protection Charge	518	0.0013	0.67	517	0.0013	0.67	0.00	0.0%	0.88%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.33%
Sub-Total: Regulatory			**3.82**			**3.82**	**0.00**	**0.0%**	**5.02%**
Debt Retirement Charge (DRC)	500	0.0070	**3.50**	500	0.0070	**3.50**	**0.00**	**0.0%**	**4.60%**
Total Bill before Taxes			**65.04**			**67.32**	**2.28**	**3.5%**	**88.50%**
GST	65.04	13%	**8.46**	67.32	13%	**8.75**	**0.29**	**3.4%**	**11.50%**
Total Bill			**73.50**			**76.07**	**2.57**	**3.5%**	**100.00%**

Table 4: Residential Bill Impacts

Consumption	800	kWh	*Loss Factor Old*			1.0356			
RPP Tier One	600	kWh	*Loss Factor New*			1.0349			
Residential	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.0%	33.74%
Energy Second Tier (kWh)	228	0.0750	17.14	228	0.0750	17.09	-0.05	(0.3)%	14.79%
Sub-Total: Energy			**56.14**			**56.09**	**-0.05**	**(0.1)%**	**48.53%**
Service Charge	1	10.60	10.60	1	11.27	11.27	0.67	6.3%	9.75%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.89%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.24%
Distribution Volumetric Rate	800	0.0154	12.32	800	0.0160	12.80	0.48	3.9%	11.07%
Distribution Volumetric Rate Rider (2011) Group 2	828	0.0000	0.00	828	0.0010	0.83	0.83	0.0%	0.72%
LRAM Volumetric Rate Rider (2011)	800	0.0000	0.00	800	0.0010	0.80	0.80	0.0%	0.69%
Distribution Volumetric Rate Rider (2010) Group 1	828	-0.0020	-1.66	828	-0.0020	-1.66	0.00	0.0%	-1.44%
Total: Distribution			**22.26**			**25.35**	**3.09**	**13.9%**	**21.93%**
Retail Transmission Rate – Network Service Rate	828	0.0061	5.05	828	0.0061	5.05	0.00	0.0%	4.37%
Retail Transmission Rate – Line and Transformation Connection	828	0.0051	4.23	828	0.0051	4.22	-0.01	(0.2)%	3.65%
Retail Transmission Rate – Low Voltage Volumetric Rate	828	0.0000	0.00	828	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**9.28**			**9.27**	**-0.01**	**(0.1)%**	**8.02%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**31.54**			**34.62**	**3.08**	**9.8%**	**29.95%**
Wholesale Market Service Rate	828	0.0056	4.64	828	0.0056	4.64	0.00	0.0%	4.01%
Rural Rate Protection Charge	828	0.0013	1.08	828	0.0013	1.08	0.00	0.0%	0.93%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.22%
Sub-Total: Regulatory			**5.97**			**5.97**	**0.00**	**0.0%**	**5.17%**
Debt Retirement Charge (DRC)	800	0.0070	**5.60**	800	0.0070	**5.60**	**0.00**	**0.0%**	**4.85%**
Total Bill before Taxes			**99.25**			**102.28**	**3.03**	**3.1%**	**88.49%**
GST	99.25	13%	**12.90**	102.28	13%	**13.30**	**0.40**	**3.1%**	**11.51%**
Total Bill			**112.15**			**115.58**	**3.43**	**3.1%**	**100.00%**

Table 5: Residential Bill Impacts

Consumption	**1,000**	**kWh**	***Loss Factor Old***			**1.0356**			
RPP Tier One	**600**	**kWh**	***Loss Factor New***			**1.0349**			
Residential	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.0%	27.36%
Energy Second Tier (kWh)	436	0.0750	32.67	435	0.0750	32.62	-0.05	(0.2)%	22.88%
Sub-Total: Energy			**71.67**			**71.62**	**-0.05**	**(0.1)%**	**50.24%**
Service Charge	1	10.60	10.60	1	11.27	11.27	0.67	6.3%	7.91%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.72%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.20%
Distribution Volumetric Rate	1,000	0.0154	15.40	1,000	0.0160	16.00	0.60	3.9%	11.22%
Distribution Volumetric Rate Rider (2011) Group 2	1,036	0.0000	0.00	1,035	0.0010	1.03	1.03	0.0%	0.72%
LRAM Volumetric Rate Rider (2011)	1,000	0.0000	0.00	1,000	0.0010	1.00	1.00	0.0%	0.70%
Distribution Volumetric Rate Rider (2010) Group 1	1,036	-0.0020	-2.07	1,035	-0.0020	-2.07	0.00	0.0%	-1.45%
Total: Distribution			**24.93**			**28.54**	**3.61**	**14.5%**	**20.02%**
Retail Transmission Rate – Network Service Rate	1,036	0.0061	6.32	1,035	0.0061	6.31	-0.01	(0.2)%	4.43%
Retail Transmission Rate – Line and Transformation Connection	1,036	0.0051	5.28	1,035	0.0051	5.28	0.00	0.0%	3.70%
Retail Transmission Rate – Low Voltage Volumetric Rate	1,036	0.0000	0.00	1,035	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**11.60**			**11.59**	**-0.01**	**(0.1)%**	**8.13%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**36.53**			**40.13**	**3.60**	**9.9%**	**28.15%**
Wholesale Market Service Rate	1,036	0.0056	5.80	1,035	0.0056	5.80	0.00	0.0%	4.07%
Rural Rate Protection Charge	1,036	0.0013	1.35	1,035	0.0013	1.35	0.00	0.0%	0.95%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.18%
Sub-Total: Regulatory			**7.40**			**7.40**	**0.00**	**0.0%**	**5.19%**
Debt Retirement Charge (DRC)	1,000	0.0070	**7.00**	1,000	0.0070	**7.00**	**0.00**	**0.0%**	**4.91%**
Total Bill before Taxes			**122.60**			**126.15**	**3.55**	**2.9%**	**88.50%**
GST	122.60	13%	**15.94**	126.15	13%	**16.40**	**0.46**	**2.9%**	**11.50%**
Total Bill			**138.54**			**142.55**	**4.01**	**2.9%**	**100.00%**

Table 6: Residential Bill Impacts

Consumption	**1,500**	**kWh**	***Loss Factor Old***			**1.0356**			
RPP Tier One	**600**	**kWh**	***Loss Factor New***			**1.0349**			
Residential	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.0%	18.57%
Energy Second Tier (kWh)	953	0.0750	71.51	952	0.0750	71.43	-0.08	(0.1)%	34.02%
Sub-Total: Energy			**110.51**			**110.43**	**-0.08**	**(0.1)%**	**52.59%**
Service Charge	1	10.60	10.60	1	11.27	11.27	0.67	6.3%	5.37%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.49%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.13%
Distribution Volumetric Rate	1,500	0.0154	23.10	1,500	0.0160	24.00	0.90	3.9%	11.43%
Distribution Volumetric Rate Rider (2011) Group 2	1,553	0.0000	0.00	1,552	0.0010	1.55	1.55	0.0%	0.74%
LRAM Volumetric Rate Rider (2011)	1,500	0.0000	0.00	1,500	0.0010	1.50	1.50	0.0%	0.71%
Distribution Volumetric Rate Rider (2010) Group 1	1,553	-0.0020	-3.11	1,552	-0.0020	-3.10	0.01	(0.3)%	-1.48%
Total: Distribution			**31.59**			**36.53**	**4.94**	**15.6%**	**17.40%**
Retail Transmission Rate – Network Service Rate	1,553	0.0061	9.48	1,552	0.0061	9.47	-0.01	(0.1)%	4.51%
Retail Transmission Rate – Line and Transformation Connection	1,553	0.0051	7.92	1,552	0.0051	7.92	0.00	0.0%	3.77%
Retail Transmission Rate – Low Voltage Volumetric Rate	1,553	0.0000	0.00	1,552	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**17.40**			**17.39**	**-0.01**	**(0.1)%**	**8.28%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**48.99**			**53.92**	**4.93**	**10.1%**	**25.68%**
Wholesale Market Service Rate	1,553	0.0056	8.70	1,552	0.0056	8.69	-0.01	(0.1)%	4.14%
Rural Rate Protection Charge	1,553	0.0013	2.02	1,552	0.0013	2.02	0.00	0.0%	0.96%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.12%
Sub-Total: Regulatory			**10.97**			**10.96**	**-0.01**	**(0.1)%**	**5.22%**
Debt Retirement Charge (DRC)	1,500	0.0070	**10.50**	1,500	0.0070	**10.50**	**0.00**	**0.0%**	**5.00%**
Total Bill before Taxes			**180.97**			**185.81**	**4.84**	**2.7%**	**88.49%**
GST	180.97	13%	**23.53**	185.81	13%	**24.16**	**0.63**	**2.7%**	**11.51%**
Total Bill			**204.50**			**209.97**	**5.47**	**2.7%**	**100.00%**

Table 7: Residential Bill Impacts

Consumption	**2,000**	**kWh**	***Loss Factor Old***			**1.0356**			
RPP Tier One	**600**	**kWh**	***Loss Factor New***			**1.0349**			
Residential	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.0%	14.06%
Energy Second Tier (kWh)	1,471	0.0750	110.34	1,470	0.0750	110.24	-0.10	(0.1)%	39.74%
Sub-Total: Energy			**149.34**			**149.24**	**-0.10**	**(0.1)%**	**53.80%**
Service Charge	1	10.60	10.60	1	11.27	11.27	0.67	6.3%	4.06%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.37%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.10%
Distribution Volumetric Rate	2,000	0.0154	30.80	2,000	0.0160	32.00	1.20	3.9%	11.54%
Distribution Volumetric Rate Rider (2011) Group 2	2,071	0.0000	0.00	2,070	0.0010	2.07	2.07	0.0%	0.75%
LRAM Volumetric Rate Rider (2011)	2,000	0.0000	0.00	2,000	0.0010	2.00	2.00	0.0%	0.72%
Distribution Volumetric Rate Rider (2010) Group 1	2,071	-0.0020	-4.14	2,070	-0.0020	-4.14	0.00	0.0%	-1.49%
Total: Distribution			**38.26**			**44.51**	**6.25**	**16.3%**	**16.05%**
Retail Transmission Rate – Network Service Rate	2,071	0.0061	12.63	2,070	0.0061	12.63	0.00	0.0%	4.55%
Retail Transmission Rate – Line and Transformation Connection S	2,071	0.0051	10.56	2,070	0.0051	10.56	0.00	0.0%	3.81%
Retail Transmission Rate – Low Voltage Volumetric Rate	2,071	0.0000	0.00	2,070	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**23.19**			**23.19**	**0.00**	**0.0%**	**8.36%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**61.45**			**67.70**	**6.25**	**10.2%**	**24.41%**
Wholesale Market Service Rate	2,071	0.0056	11.60	2,070	0.0056	11.59	-0.01	(0.1)%	4.18%
Rural Rate Protection Charge	2,071	0.0013	2.69	2,070	0.0013	2.69	0.00	0.0%	0.97%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.09%
Sub-Total: Regulatory			**14.54**			**14.53**	**-0.01**	**(0.1)%**	**5.24%**
Debt Retirement Charge (DRC)	2,000	0.0070	**14.00**	2,000	0.0070	**14.00**	**0.00**	**0.0%**	**5.05%**
Total Bill before Taxes			**239.33**			**245.47**	**6.14**	**2.6%**	**88.50%**
GST	239.33	13%	**31.11**	245.47	13%	**31.91**	**0.80**	**2.6%**	**11.50%**
Total Bill			**270.44**			**277.38**	**6.94**	**2.6%**	**100.00%**

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Table 8: GS < 50

Consumption	**500**	**kWh**	***Loss Factor Old***			**1.0356**			
RPP Tier One	**750**	**kWh**	***Loss Factor New***			**1.0349**			
General Service < 50 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.0%	59.97%
Energy Second Tier (kWh)	-232	0.0750	-17.42	-233	0.0750	-17.44	-0.02	0.1%	-21.45%
Sub-Total: Energy			**31.33**			**31.31**	**-0.02**	**(0.1)%**	**38.52%**
Service Charge	1	20.27	20.27	1	19.19	19.19	-1.08	(5.3)%	23.61%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	1.27%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.34%
Distribution Volumetric Rate	500	0.0178	8.90	500	0.0166	8.30	-0.60	(6.7)%	10.21%
Distribution Volumetric Rate Rider (2011) Group 2	518	0.0000	0.00	517	0.0008	0.41	0.41	0.0%	0.50%
LRAM Volumetric Rate Rider (2011)	500	0.0000	0.00	500	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	518	-0.0020	-1.04	517	-0.0020	-1.03	0.01	(1.0)%	-1.27%
Total: Distribution			**29.13**			**28.18**	**-0.95**	**(3.3)%**	**34.67%**
Retail Transmission Rate – Network Service Rate	518	0.0055	2.85	517	0.0055	2.85	0.00	0.0%	3.51%
Retail Transmission Rate – Line and Transformation Connection	518	0.0044	2.28	517	0.0044	2.28	0.00	0.0%	2.80%
Retail Transmission Rate – Low Voltage Volumetric Rate	518	0.0000	0.00	517	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**5.13**			**5.13**	**0.00**	**0.0%**	**6.31%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**34.26**			**33.31**	**-0.95**	**(2.8)%**	**40.98%**
Wholesale Market Service Rate	518	0.0056	2.90	517	0.0056	2.90	0.00	0.0%	3.57%
Rural Rate Protection Charge	518	0.0013	0.67	517	0.0013	0.67	0.00	0.0%	0.82%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.31%
Sub-Total: Regulatory			**3.82**			**3.82**	**0.00**	**0.0%**	**4.70%**
Debt Retirement Charge (DRC)	500	0.0070	**3.50**	500	0.0070	**3.50**	**0.00**	**0.0%**	**4.31%**
Total Bill before Taxes			**72.91**			**71.94**	**-0.97**	**(1.3)%**	**88.50%**
GST	72.91	13%	**9.48**	71.94	13%	**9.35**	**-0.13**	**(1.4)%**	**11.50%**
Total Bill			**82.39**			**81.29**	**-1.10**	**(1.3)%**	**100.00%**

Table 9: GS < 50

Consumption	**1,000**	**kWh**	***Loss Factor Old***			**1.0356**			
RPP Tier One	**750**	**kWh**	***Loss Factor New***			**1.0349**			
General Service < 50 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.0%	33.03%
Energy Second Tier (kWh)	286	0.0750	21.42	285	0.0750	21.37	-0.05	(0.2)%	14.48%
Sub-Total: Energy			**70.17**			**70.12**	**-0.05**	**(0.1)%**	**47.51%**
Service Charge	1	20.27	20.27	1	19.19	19.19	-1.08	(5.3)%	13.00%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.70%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.19%
Distribution Volumetric Rate	1,000	0.0178	17.80	1,000	0.0166	16.60	-1.20	(6.7)%	11.25%
Distribution Volumetric Rate Rider (2011) Group 2	1,036	0.0000	0.00	1,035	0.0008	0.83	0.83	0.0%	0.56%
LRAM Volumetric Rate Rider (2011)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	1,036	-0.0020	-2.07	1,035	-0.0020	-2.07	0.00	0.0%	-1.40%
Total: Distribution			**37.00**			**35.86**	**-1.14**	**(3.1)%**	**24.30%**
Retail Transmission Rate – Network Service Rate	1,036	0.0055	5.70	1,035	0.0055	5.69	-0.01	(0.2)%	3.86%
Retail Transmission Rate – Line and Transformation Connection	1,036	0.0044	4.56	1,035	0.0044	4.55	-0.01	(0.2)%	3.08%
Retail Transmission Rate – Low Voltage Volumetric Rate	1,036	0.0000	0.00	1,035	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**10.26**			**10.24**	**-0.02**	**(0.2)%**	**6.94%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**47.26**			**46.10**	**-1.16**	**(2.5)%**	**31.23%**
Wholesale Market Service Rate	1,036	0.0056	5.80	1,035	0.0056	5.80	0.00	0.0%	3.93%
Rural Rate Protection Charge	1,036	0.0013	1.35	1,035	0.0013	1.35	0.00	0.0%	0.91%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.17%
Sub-Total: Regulatory			**7.40**			**7.40**	**0.00**	**0.0%**	**5.01%**
Debt Retirement Charge (DRC)	1,000	0.0070	**7.00**	1,000	0.0070	**7.00**	**0.00**	**0.0%**	**4.74%**
Total Bill before Taxes			**131.83**			**130.62**	**-1.21**	**(0.9)%**	**88.50%**
GST	131.83	13%	**17.14**	130.62	13%	**16.98**	**-0.16**	**(0.9)%**	**11.50%**
Total Bill			**148.97**			**147.60**	**-1.37**	**(0.9)%**	**100.00%**

Table 10: GS < 50

Consumption	**2,000**	**kWh**	***Loss Factor Old***		**1.0356**			
RPP Tier One	**750**	**kWh**	***Loss Factor New***		**1.0349**			
General Service < 50 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.0%	17.40%
Energy Second Tier (kWh)	1,321	0.0750	99.09	1,320	0.0750	98.99	-0.10	(0.1)%	35.33%
Sub-Total: Energy			**147.84**			**147.74**	**-0.10**	**(0.1)%**	**52.72%**
Service Charge	1	20.27	20.27	1	19.19	19.19	-1.08	(5.3)%	6.85%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.37%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.10%
Distribution Volumetric Rate	2,000	0.0178	35.60	2,000	0.0166	33.20	-2.40	(6.7)%	11.85%
Distribution Volumetric Rate Rider (2011) Group 2	2,071	0.0000	0.00	2,070	0.0008	1.66	1.66	0.0%	0.59%
LRAM Volumetric Rate Rider (2011)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	2,071	-0.0020	-4.14	2,070	-0.0020	-4.14	0.00	0.0%	-1.48%
Total: Distribution			**52.73**			**51.22**	**-1.51**	**(2.9)%**	**18.28%**
Retail Transmission Rate – Network Service Rate	2,071	0.0055	11.39	2,070	0.0055	11.38	-0.01	(0.1)%	4.06%
Retail Transmission Rate – Line and Transformation Connection	2,071	0.0044	9.11	2,070	0.0044	9.11	0.00	0.0%	3.25%
Retail Transmission Rate – Low Voltage Volumetric Rate	2,071	0.0000	0.00	2,070	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**20.50**			**20.49**	**-0.01**	**(0.0)%**	**7.31%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**73.23**			**71.71**	**-1.52**	**(2.1)%**	**25.59%**
Wholesale Market Service Rate	2,071	0.0056	11.60	2,070	0.0056	11.59	-0.01	(0.1)%	4.14%
Rural Rate Protection Charge	2,071	0.0013	2.69	2,070	0.0013	2.69	0.00	0.0%	0.96%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.09%
Sub-Total: Regulatory			**14.54**			**14.53**	**-0.01**	**(0.1)%**	**5.19%**
Debt Retirement Charge (DRC)	2,000	0.0070	**14.00**	2,000	0.0070	**14.00**	**0.00**	**0.0%**	**5.00%**
Total Bill before Taxes			**249.61**			**247.98**	**-1.63**	**(0.7)%**	**88.49%**
GST	249.61	13%	**32.45**	247.98	13%	**32.24**	**-0.21**	**(0.6)%**	**11.51%**
Total Bill			**282.06**			**280.22**	**-1.84**	**(0.7)%**	**100.00%**

Table 11: GS < 50

Consumption	**3,000**	**kWh**	***Loss Factor Old***		**1.0356**			
RPP Tier One	**750**	**kWh**	***Loss Factor New***		**1.0349**			
General Service < 50 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0650	48.75	750	0.0650	48.75	0.00	0.0%	11.81%
Energy Second Tier (kWh)	2,357	0.0750	176.76	2,355	0.0750	176.60	-0.16	(0.1)%	42.78%
Sub-Total: Energy			**225.51**			**225.35**	**-0.16**	**(0.1)%**	**54.59%**
Service Charge	1	20.27	20.27	1	19.19	19.19	-1.08	(5.3)%	4.65%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.25%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.07%
Distribution Volumetric Rate	3,000	0.0178	53.40	3,000	0.0166	49.80	-3.60	(6.7)%	12.06%
Distribution Volumetric Rate Rider (2011) Group 2	3,107	0.0000	0.00	3,105	0.0008	2.48	2.48	0.0%	0.60%
LRAM Volumetric Rate Rider (2011)	3,000	0.0000	0.00	3,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	3,107	-0.0020	-6.21	3,105	-0.0020	-6.21	0.00	0.0%	-1.50%
Total: Distribution			**68.46**			**66.57**	**-1.89**	**(2.8)%**	**16.13%**
Retail Transmission Rate – Network Service Rate	3,107	0.0055	17.09	3,105	0.0055	17.08	-0.01	(0.1)%	4.14%
Retail Transmission Rate – Line and Transformation Connection	3,107	0.0044	13.67	3,105	0.0044	13.66	-0.01	(0.1)%	3.31%
Retail Transmission Rate – Low Voltage Volumetric Rate	3,107	0.0000	0.00	3,105	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**30.76**			**30.74**	**-0.02**	**(0.1)%**	**7.45%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**99.22**			**97.31**	**-1.91**	**(1.9)%**	**23.57%**
Wholesale Market Service Rate	3,107	0.0056	17.40	3,105	0.0056	17.39	-0.01	(0.1)%	4.21%
Rural Rate Protection Charge	3,107	0.0013	4.04	3,105	0.0013	4.04	0.00	0.0%	0.98%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.06%
Sub-Total: Regulatory			**21.69**			**21.68**	**-0.01**	**(0.0)%**	**5.25%**
Debt Retirement Charge (DRC)	3,000	0.0070	**21.00**	3,000	0.0070	**21.00**	**0.00**	**0.0%**	**5.09%**
Total Bill before Taxes			**367.42**			**365.34**	**-2.08**	**(0.6)%**	**88.50%**
GST	367.42	13%	**47.76**	365.34	13%	**47.49**	**-0.27**	**(0.6)%**	**11.50%**
Total Bill			**415.18**			**412.83**	**-2.35**	**(0.6)%**	**100.00%**

Table 12: GS < 50

Consumption	**5,000**	**kWh**	***Loss Factor Old***		**1.0356**			
RPP Tier One	**600**	**kWh**	***Loss Factor New***		**1.0349**			
General Service < 50 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	600	0.0650	39.00	600	0.0650	39.00	0.00	0.0%	5.74%
Energy Second Tier (kWh)	4,578	0.0750	343.35	4,575	0.0750	343.09	-0.26	(0.1)%	50.47%
Sub-Total: Energy			**382.35**			**382.09**	**-0.26**	**(0.1)%**	**56.21%**
Service Charge	1	20.27	20.27	1	19.19	19.19	-1.08	(5.3)%	2.82%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.15%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.28	0.28	0.28	0.0%	0.04%
Distribution Volumetric Rate	5,000	0.0178	89.00	5,000	0.0166	83.00	-6.00	(6.7)%	12.21%
Distribution Volumetric Rate Rider (2011) Group 2	5,178	0.0000	0.00	5,175	0.0008	4.14	4.14	0.0%	0.61%
LRAM Volumetric Rate Rider (2011)	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	5,178	-0.0020	-10.36	5,175	-0.0020	-10.35	0.01	(0.1)%	-1.52%
Total: Distribution			**99.91**			**97.29**	**-2.62**	**(2.6)%**	**14.31%**
Retail Transmission Rate – Network Service Rate	5,178	0.0055	28.48	5,175	0.0055	28.46	-0.02	(0.1)%	4.19%
Retail Transmission Rate – Line and Transformation Connection	5,178	0.0044	22.78	5,175	0.0044	22.77	-0.01	(0.0)%	3.35%
Retail Transmission Rate – Low Voltage Volumetric Rate	5,178	0.0000	0.00	5,175	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**51.26**			**51.23**	**-0.03**	**(0.1)%**	**7.54%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**151.17**			**148.52**	**-2.65**	**(1.8)%**	**21.85%**
Wholesale Market Service Rate	5,178	0.0056	29.00	5,175	0.0056	28.98	-0.02	(0.1)%	4.26%
Rural Rate Protection Charge	5,178	0.0013	6.73	5,175	0.0013	6.73	0.00	0.0%	0.99%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.04%
Sub-Total: Regulatory			**35.98**			**35.96**	**-0.02**	**(0.1)%**	**5.29%**
Debt Retirement Charge (DRC)	5,000	0.0070	**35.00**	5,000	0.0070	**35.00**	**0.00**	**0.0%**	**5.15%**
Total Bill before Taxes			**604.50**			**601.57**	**-2.93**	**(0.5)%**	**88.50%**
GST	604.50	13%	**78.59**	601.57	13%	**78.20**	**-0.39**	**(0.5)%**	**11.50%**
Total Bill			**683.09**			**679.77**	**-3.32**	**(0.5)%**	**100.00%**

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Table 13: GS > 50 < 700

Consumption	**28,123**	**kWh**	**84**	**kW**	***Loss Factor Old***	***1.0356***	
RPP Tier One	**750**	**kWh**	***Load Factor***	***45.0%***	***Loss Factor New***	***1.0349***	

General Service 50 to 699 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	1.49%
Energy Second Tier (kWh)	28,374	0.0694	1,968.61	28,355	0.0694	1,967.25	-1.36	(0.1)%	56.48%
Sub-Total: Energy			**2,020.65**			**2,019.29**	**-1.36**	**(0.1)%**	**57.98%**
Service Charge	1	101.68	101.68	1	121.67	121.67	19.99	19.7%	3.49%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.03%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.01%
Distribution Volumetric Rate	84	2.2935	192.65	84	2.7269	229.06	36.41	18.9%	6.58%
Global Adjustment Rate Rider	84	0.4861	40.83	84	0.4861	40.83	0.00	0.0%	1.17%
Distribution Volumetric Rate Rider (2011) Group 2	84	0.0000	0.00	84	0.1357	11.40	11.40	0.0%	0.33%
LRAM Volumetric Rate Rider (2011)	84	0.0000	0.00	84	0.0079	0.66	0.66	0.0%	0.02%
Distribution Volumetric Rate Rider (2010) Group 1	84	-0.7321	-61.50	84	-0.7321	-61.50	0.00	0.0%	-1.77%
Total: Distribution			**274.66**			**343.43**	**68.77**	**25.0%**	**9.86%**
Retail Transmission Rate – Network Service Rate	84	2.1307	178.98	84	2.1307	178.98	0.00	0.0%	5.14%
Retail Transmission Rate – Line and Transformation Connection S	84	1.6973	142.57	84	1.6973	142.57	0.00	0.0%	4.09%
Retail Transmission Rate – Low Voltage Volumetric Rate	84	0.0000	0.00	84	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**321.55**			**321.55**	**0.00**	**0.0%**	**9.23%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**596.21**			**664.98**	**68.77**	**11.5%**	**19.09%**
Wholesale Market Service Rate	29,124	0.0056	163.10	29,105	0.0056	162.99	-0.11	(0.1)%	4.68%
Rural Rate Protection Charge	29,124	0.0013	37.86	29,105	0.0013	37.84	-0.02	(0.1)%	1.09%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.01%
Sub-Total: Regulatory			**201.21**			**201.08**	**-0.13**	**(0.1)%**	**5.77%**
Debt Retirement Charge (DRC)	28,123	0.0070	**196.86**	28,123	0.0070	**196.86**	**0.00**	**0.0%**	**5.65%**
Total Bill before Taxes			**3,014.93**			**3,082.21**	**67.28**	**2.2%**	**88.50%**
GST	3,014.93	13%	**391.94**	3,082.21	13%	**400.69**	**8.75**	**2.2%**	**11.50%**
Total Bill			**3,406.87**			**3,482.90**	**76.03**	**2.2%**	**100.00%**

Table 14: GS > 50 < 700

Consumption	**68,448**	**kWh**	**184**	**kW**	***Loss Factor Old***	***1.0356***	
RPP Tier One	**750**	**kWh**	***Load Factor***	***50.0%***	***Loss Factor New***	***1.0349***	

General Service 50 to 699 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.64%
Energy Second Tier (kWh)	70,135	0.0694	4,865.95	70,087	0.0694	4,862.62	-3.33	(0.1)%	59.82%
Sub-Total: Energy			**4,917.99**			**4,914.66**	**-3.33**	**(0.1)%**	**60.46%**
Service Charge	1	101.68	101.68	1	121.67	121.67	19.99	19.7%	1.50%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.01%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	184	2.2935	422.00	184	2.7269	501.75	79.75	18.9%	6.17%
Global Adjustment Rate Rider	184	0.4861	89.44	184	0.4861	89.44	0.00	0.0%	1.10%
Distribution Volumetric Rate Rider (2011) Group 2	184	0.0000	0.00	184	0.1357	24.97	24.97	0.0%	0.31%
LRAM Volumetric Rate Rider (2011)	184	0.0000	0.00	184	0.0079	1.45	1.45	0.0%	0.02%
Distribution Volumetric Rate Rider (2010) Group 1	184	-0.7321	-134.71	184	-0.7321	-134.71	0.00	0.0%	-1.66%
Total: Distribution			**479.41**			**605.88**	**126.47**	**26.4%**	**7.45%**
Retail Transmission Rate – Network Service Rate	184	2.1307	392.05	184	2.1307	392.05	0.00	0.0%	4.82%
Retail Transmission Rate – Line and Transformation Connection S	184	1.6973	312.30	184	1.6973	312.30	0.00	0.0%	3.84%
Retail Transmission Rate – Low Voltage Volumetric Rate	184	0.0000	0.00	184	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**704.35**			**704.35**	**0.00**	**0.0%**	**8.67%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**1,183.76**			**1,310.23**	**126.47**	**10.7%**	**16.12%**
Wholesale Market Service Rate	70,885	0.0056	396.95	70,837	0.0056	396.69	-0.26	(0.1)%	4.88%
Rural Rate Protection Charge	70,885	0.0013	92.15	70,837	0.0013	92.09	-0.06	(0.1)%	1.13%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**489.35**			**489.03**	**-0.32**	**(0.1)%**	**6.02%**
Debt Retirement Charge (DRC)	68,448	0.0070	**479.14**	68,448	0.0070	**479.14**	**0.00**	**0.0%**	**5.89%**
Total Bill before Taxes			**7,070.24**			**7,193.06**	**122.82**	**1.7%**	**88.50%**
GST	7,070.24	13%	**919.13**	7,193.06	13%	**935.10**	**15.97**	**1.7%**	**11.50%**
Total Bill			**7,989.37**			**8,128.16**	**138.79**	**1.7%**	**100.00%**

Table 15: GS > 50 < 700

Consumption	**88,536**	**kWh**	**238**	**kW**	***Loss Factor Old***	***1.0356***			
RPP Tier One	**750**	**kWh**	***Load Factor***	***50.0%***	***Loss Factor New***	***1.0349***			

General Service 50 to 699 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.50%
Energy Second Tier (kWh)	90,938	0.0694	6,309.27	90,876	0.0694	6,304.97	-4.30	(0.1)%	60.20%
Sub-Total: Energy			**6,361.31**			**6,357.01**	**-4.30**	**(0.1)%**	**60.70%**
Service Charge	1	101.68	101.68	1	121.67	121.67	19.99	19.7%	1.16%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.01%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	238	2.2935	545.85	238	2.7269	649.00	103.15	18.9%	6.20%
Global Adjustment Rate Rider	238	0.4861	115.69	238	0.4861	115.69	0.00	0.0%	1.10%
Distribution Volumetric Rate Rider (2011) Group 2	238	0.0000	0.00	238	0.1357	32.30	32.30	0.0%	0.31%
LRAM Volumetric Rate Rider (2011)	238	0.0000	0.00	238	0.0079	1.88	1.88	0.0%	0.02%
Distribution Volumetric Rate Rider (2010) Group 1	238	-0.7321	-174.24	238	-0.7321	-174.24	0.00	0.0%	-1.66%
Total: Distribution			**589.98**			**747.61**	**157.63**	**26.7%**	**7.14%**
Retail Transmission Rate – Network Service Rate	238	2.1307	507.11	238	2.1307	507.11	0.00	0.0%	4.84%
Retail Transmission Rate – Line and Transformation Connection S	238	1.6973	403.96	238	1.6973	403.96	0.00	0.0%	3.86%
Retail Transmission Rate – Low Voltage Volumetric Rate	238	0.0000	0.00	238	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**911.07**			**911.07**	**0.00**	**0.0%**	**8.70%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**1,501.05**			**1,658.68**	**157.63**	**10.5%**	**15.84%**
Wholesale Market Service Rate	91,688	0.0056	513.45	91,626	0.0056	513.11	-0.34	(0.1)%	4.90%
Rural Rate Protection Charge	91,688	0.0013	119.19	91,626	0.0013	119.11	-0.08	(0.1)%	1.14%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**632.89**			**632.47**	**-0.42**	**(0.1)%**	**6.04%**
Debt Retirement Charge (DRC)	88,536	0.0070	**619.75**	88,536	0.0070	**619.75**	**0.00**	**0.0%**	**5.92%**
Total Bill before Taxes			**9,115.00**			**9,267.91**	**152.91**	**1.7%**	**88.50%**
GST	9,115.00	13%	**1,184.95**	9,267.91	13%	**1,204.83**	**19.88**	**1.7%**	**11.50%**
Total Bill			**10,299.95**			**10,472.74**	**172.79**	**1.7%**	**100.00%**

Table 16: GS > 50 < 700

Consumption	**215,760**	**kWh**	**500**	**kW**	***Loss Factor Old***	***1.0356***			
RPP Tier One	**750**	**kWh**	***Load Factor***	***58.0%***	***Loss Factor New***	***1.0349***			

General Service 50 to 699 kW	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.21%
Energy Second Tier (kWh)	222,691	0.0694	15,450.31	222,540	0.0694	15,439.83	-10.48	(0.1)%	62.41%
Sub-Total: Energy			**15,502.35**			**15,491.87**	**-10.48**	**(0.1)%**	**62.62%**
Service Charge	1	101.68	101.68	1	121.67	121.67	19.99	19.7%	0.49%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.00%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	500	2.2935	1,146.75	500	2.7269	1,363.45	216.70	18.9%	5.51%
Global Adjustment Rate Rider	500	0.4861	243.05	500	0.4861	243.05	0.00	0.0%	0.98%
Distribution Volumetric Rate Rider (2011) Group 2	500	0.0000	0.00	500	0.1357	67.85	67.85	0.0%	0.27%
LRAM Volumetric Rate Rider (2011)	500	0.0000	0.00	500	0.0079	3.95	3.95	0.0%	0.02%
Distribution Volumetric Rate Rider (2010) Group 1	500	-0.7321	-366.05	500	-0.7321	-366.05	0.00	0.0%	-1.48%
Total: Distribution			**1,126.43**			**1,435.23**	**308.80**	**27.4%**	**5.80%**
Retail Transmission Rate – Network Service Rate	500	2.1307	1,065.35	500	2.1307	1,065.35	0.00	0.0%	4.31%
Retail Transmission Rate – Line and Transformation Connection S	500	1.6973	848.65	500	1.6973	848.65	0.00	0.0%	3.43%
Retail Transmission Rate – Low Voltage Volumetric Rate	500	0.0000	0.00	500	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**1,914.00**			**1,914.00**	**0.00**	**0.0%**	**7.74%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**3,040.43**			**3,349.23**	**308.80**	**10.2%**	**13.54%**
Wholesale Market Service Rate	223,441	0.0056	1,251.27	223,290	0.0056	1,250.42	-0.85	(0.1)%	5.05%
Rural Rate Protection Charge	223,441	0.0013	290.47	223,290	0.0013	290.28	-0.19	(0.1)%	1.17%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**1,541.99**			**1,540.95**	**-1.04**	**(0.1)%**	**6.23%**
Debt Retirement Charge (DRC)	215,760	0.0070	**1,510.32**	215,760	0.0070	**1,510.32**	**0.00**	**0.0%**	**6.11%**
Total Bill before Taxes			**21,595.09**			**21,892.37**	**297.28**	**1.4%**	**88.50%**
GST	21,595.09	13%	**2,807.36**	21,892.37	13%	**2,846.01**	**38.65**	**1.4%**	**11.50%**
Total Bill			**24,402.45**			**24,738.38**	**335.93**	**1.4%**	**100.00%**

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Table 17: GS > 700 < 5000

Consumption	503,710	kWh	857	kW		*Loss Factor Old*	*1.0356*		
RPP Tier One	750	kWh	*Load Factor*	*79.0%*		*Loss Factor New*	*1.0349*		

General Service 700 - 4,999	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.09%
Energy Second Tier (kWh)	520,892	0.0694	36,139.52	520,540	0.0694	36,115.05	-24.47	(0.1)%	62.17%
Sub-Total: Energy			**36,191.56**			**36,167.09**	**-24.47**	**(0.1)%**	**62.26%**
Service Charge	1	1410.45	1,410.45	1	1333.27	1,333.27	-77.18	(5.5)%	2.30%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.00%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	857	3.7355	3,201.32	857	3.7887	3,246.92	45.60	1.4%	5.59%
Global Adjustment Rate Rider	857	0.5881	504.00	857	0.5881	503.98	-0.02	(0.0)%	0.87%
Distribution Volumetric Rate Rider (2011) Group 2	857	0.0000	0.00	857	0.1778	152.37	152.37	0.0%	0.26%
LRAM Volumetric Rate Rider (2011)	857	0.0000	0.00	857	0.0378	32.39	32.39	0.0%	0.06%
Distribution Volumetric Rate Rider (2010) Group 1	857	-0.8881	-761.10	857	-0.8881	-761.10	0.00	0.0%	-1.31%
Total: Distribution			**4,355.67**			**4,509.14**	**153.47**	**3.5%**	**7.76%**
Retail Transmission Rate – Network Service Rate	857	2.3896	2,047.89	857	2.3896	2,047.89	0.00	0.0%	3.53%
Retail Transmission Rate – Line and Transformation Connection	857	1.8245	1,563.60	857	1.8245	1,563.60	0.00	0.0%	2.69%
Retail Transmission Rate – Low Voltage Volumetric Rate	857	0.0000	0.00	857	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**3,611.49**			**3,611.49**	**0.00**	**0.0%**	**6.22%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**7,967.16**			**8,120.63**	**153.47**	**1.9%**	**13.98%**
Wholesale Market Service Rate	521,642	0.0056	2,921.20	521,290	0.0056	2,919.22	-1.98	(0.1)%	5.02%
Rural Rate Protection Charge	521,642	0.0013	678.14	521,290	0.0013	677.68	-0.46	(0.1)%	1.17%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**3,599.59**			**3,597.15**	**-2.44**	**(0.1)%**	**6.19%**
Debt Retirement Charge (DRC)	503,710	0.0070	**3,525.97**	503,710	0.0070	**3,525.97**	**0.00**	**0.0%**	**6.07%**
Total Bill before Taxes			**51,284.28**			**51,410.84**	**126.56**	**0.2%**	**88.50%**
GST	51,284.28	13%	**6,666.96**	51,410.84	13%	**6,683.41**	**16.45**	**0.2%**	**11.50%**
Total Bill			**57,951.24**			**58,094.25**	**143.01**	**0.2%**	**100.00%**

Table 18: GS > 700 < 5000

Consumption	773,388	kWh	1,350	kW		*Loss Factor Old*	*1.0356*		
RPP Tier One	750	kWh	*Load Factor*	*77.0%*		*Loss Factor New*	*1.0349*		

General Service 700 - 4,999	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.06%
Energy Second Tier (kWh)	800,171	0.0694	55,515.84	799,629	0.0694	55,478.28	-37.56	(0.1)%	62.55%
Sub-Total: Energy			**55,567.88**			**55,530.32**	**-37.56**	**(0.1)%**	**62.61%**
Service Charge	1	1410.45	1,410.45	1	1333.27	1,333.27	-77.18	(5.5)%	1.50%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.00%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	1,350	3.7355	5,042.93	1,350	3.7887	5,114.75	71.82	1.4%	5.77%
Global Adjustment Rate Rider	1,350	0.5881	793.94	1,350	0.5881	793.89	-0.05	(0.0)%	0.90%
Distribution Volumetric Rate Rider (2011) Group 2	1,350	0.0000	0.00	1,350	0.1778	240.03	240.03	0.0%	0.27%
LRAM Volumetric Rate Rider (2011)	1,350	0.0000	0.00	1,350	0.0378	51.03	51.03	0.0%	0.06%
Distribution Volumetric Rate Rider (2010) Group 1	1,350	-0.8881	-1,198.94	1,350	-0.8881	-1,198.94	0.00	0.0%	-1.35%
Total: Distribution			**6,049.38**			**6,335.34**	**285.96**	**4.7%**	**7.14%**
Retail Transmission Rate – Network Service Rate	1,350	2.3896	3,225.96	1,350	2.3896	3,225.96	0.00	0.0%	3.64%
Retail Transmission Rate – Line and Transformation Connection	1,350	1.8245	2,463.08	1,350	1.8245	2,463.08	0.00	0.0%	2.78%
Retail Transmission Rate – Low Voltage Volumetric Rate	1,350	0.0000	0.00	1,350	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**5,689.04**			**5,689.04**	**0.00**	**0.0%**	**6.41%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**11,738.42**			**12,024.38**	**285.96**	**2.4%**	**13.56%**
Wholesale Market Service Rate	800,921	0.0056	4,485.16	800,379	0.0056	4,482.12	-3.04	(0.1)%	5.05%
Rural Rate Protection Charge	800,921	0.0013	1,041.20	800,379	0.0013	1,040.49	-0.71	(0.1)%	1.17%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**5,526.61**			**5,522.86**	**-3.75**	**(0.1)%**	**6.23%**
Debt Retirement Charge (DRC)	773,388	0.0070	**5,413.72**	773,388	0.0070	**5,413.72**	**0.00**	**0.0%**	**6.10%**
Total Bill before Taxes			**78,246.63**			**78,491.28**	**244.65**	**0.3%**	**88.50%**
GST	78,246.63	13%	**10,172.06**	78,491.28	13%	**10,203.87**	**31.81**	**0.3%**	**11.50%**
Total Bill			**88,418.69**			**88,695.15**	**276.46**	**0.3%**	**100.00%**

Table 19: GS > 700 < 5000

Consumption	**1,249,920**	**kWh**	**2,100**	**kW**		***Loss Factor Old***	***1.0356***		
RPP Tier One	**750**	**kWh**	***Load Factor***	***80.0%***		***Loss Factor New***	***1.0349***		
General Service 700 - 4,999	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.04%
Energy Second Tier (kWh)	1,293,667	0.0694	89,754.63	1,292,792	0.0694	89,693.92	-60.71	(0.1)%	63.31%
Sub-Total: Energy			**89,806.67**			**89,745.96**	**-60.71**	**(0.1)%**	**63.34%**
Service Charge	1	1410.45	1,410.45	1	1333.27	1,333.27	-77.18	(5.5)%	0.94%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.00%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	2,100	3.7355	7,844.55	2,100	3.7887	7,956.27	111.72	1.4%	5.62%
Global Adjustment Rate Rider	2,100	0.5881	1,235.01	2,100	0.5881	1,234.95	-0.06	(0.0)%	0.87%
Distribution Volumetric Rate Rider (2011) Group 2	2,100	0.0000	0.00	2,100	0.1778	373.38	373.38	0.0%	0.26%
LRAM Volumetric Rate Rider (2011)	2,100	0.0000	0.00	2,100	0.0378	79.38	79.38	0.0%	0.06%
Distribution Volumetric Rate Rider (2010) Group 1	2,100	-0.8881	-1,865.01	2,100	-0.8881	-1,865.01	0.00	0.0%	-1.32%
Total: Distribution			**8,626.00**			**9,113.55**	**487.55**	**5.7%**	**6.43%**
Retail Transmission Rate – Network Service Rate	2,100	2.3896	5,018.16	2,100	2.3896	5,018.16	0.00	0.0%	3.54%
Retail Transmission Rate – Line and Transformation Connection	2,100	1.8245	3,831.45	2,100	1.8245	3,831.45	0.00	0.0%	2.70%
Retail Transmission Rate – Low Voltage Volumetric Rate	2,100	0.0000	0.00	2,100	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**8,849.61**			**8,849.61**	**0.00**	**0.0%**	**6.25%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**17,475.61**			**17,963.16**	**487.55**	**2.8%**	**12.68%**
Wholesale Market Service Rate	1,294,417	0.0056	7,248.74	1,293,542	0.0056	7,243.84	-4.90	(0.1)%	5.11%
Rural Rate Protection Charge	1,294,417	0.0013	1,682.74	1,293,542	0.0013	1,681.60	-1.14	(0.1)%	1.19%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**8,931.73**			**8,925.69**	**-6.04**	**(0.1)%**	**6.30%**
Debt Retirement Charge (DRC)	1,249,920	0.0070	**8,749.44**	1,249,920	0.0070	**8,749.44**	**0.00**	**0.0%**	**6.18%**
Total Bill before Taxes			**124,963.45**			**125,384.25**	**420.80**	**0.3%**	**88.50%**
GST	124,963.45	13%	**16,245.25**	125,384.25	13%	**16,299.95**	**54.70**	**0.3%**	**11.50%**
Total Bill			**141,208.70**			**141,684.20**	**475.50**	**0.3%**	**100.00%**

Table 20: Large Use

Consumption	**3,124,800**	**kWh**	**6,000**	**kW**		***Loss Factor Old***	***1.0045***		
RPP Tier One	**750**	**kWh**	***Load Factor***	***70.0%***		***Loss Factor New***	***1.0045***		

Large Use	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.01%
Energy Second Tier (kWh)	3,138,112	0.0694	217,722.18	3,138,112	0.0694	217,722.18	0.00	0.0%	62.28%
Sub-Total: Energy			**217,774.22**			**217,774.22**	**0.00**	**0.0%**	**62.29%**
Service Charge	1	4,722.33	4,722.33	1	5,208.02	5,208.02	485.69	10.3%	1.49%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.00%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	6,000	2.9023	17,413.80	6000	2.5225	15,135.00	-2,278.80	(13.1)%	4.33%
Global Adjustment Rate Rider	6,000	0.7109	4,265.40	6,000	0.7109	4,265.40	0.00	0.0%	1.22%
Distribution Volumetric Rate Rider (2011) Group 2	6,000	0.0000	0.00	6,000	0.1574	944.40	944.40	0.0%	0.27%
LRAM Volumetric Rate Rider (2011)	6,000	0.0000	0.00	6,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	6,000	-1.0611	-6,366.60	6,000	-1.0611	-6,366.66	-0.06	0.0%	-1.82%
TX Allowance $0.60/kw	6,000	-0.6000	-3,600.00	6,000	0.0000	0.00	3,600.00	(100.0)%	0.00%
Total: Distribution			**16,435.93**			**19,187.47**	**2,751.54**	**16.7%**	**5.49%**
Retail Transmission Rate – Network Service Rate	6,000	2.7045	16,227.00	6,000	2.7045	16,227.00	0.00	0.0%	4.64%
Retail Transmission Rate – Line and Transformation Connection	6,000	2.1088	12,652.80	6,000	2.1088	12,652.80	0.00	0.0%	3.62%
Retail Transmission Rate – Low Voltage Volumetric Rate	6,000	0.0000	0.00	6,000	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**28,879.80**			**28,879.80**	**0.00**	**0.0%**	**8.26%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**45,315.73**			**48,067.27**	**2,751.54**	**6.1%**	**13.75%**
Wholesale Market Service Rate	3,138,862	0.0056	17,577.62	3,138,862	0.0056	17,577.62	0.00	0.0%	5.03%
Rural Rate Protection Charge	3,138,862	0.0013	4,080.52	3,138,862	0.0013	4,080.52	0.00	0.0%	1.17%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**21,658.39**			**21,658.39**	**0.00**	**0.0%**	**6.20%**
Debt Retirement Charge (DRC)	3,124,800	0.0070	**21,873.60**	3,124,800	0.0070	**21,873.60**	**0.00**	**0.0%**	**6.26%**
Total Bill before Taxes			**306,621.94**			**309,373.48**	**2,751.54**	**0.9%**	**88.50%**
GST	306,621.94	13%	**39,860.85**	309,373.48	13%	**40,218.55**	**357.70**	**0.9%**	**11.50%**
Total Bill			**346,482.79**			**349,592.03**	**3,109.24**	**0.9%**	**100.00%**

Table 21: Large Use

Consumption	**5,208,000**	**kWh**	**10,000**	**kW**		***Loss Factor Old***	***1.0045***		
RPP Tier One	**750**	**kWh**	***Load Factor***	***70.0%***		***Loss Factor New***	***1.0045***		

Large Use	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.01%
Energy Second Tier (kWh)	5,230,686	0.0694	362,904.99	5,230,686	0.0694	362,904.99	0.00	0.0%	62.71%
Sub-Total: Energy			**362,957.03**			**362,957.03**	**0.00**	**0.0%**	**62.72%**
Service Charge	1	4,722.33	4,722.33	1	5,208.02	5,208.02	485.69	10.3%	0.90%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.00%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	10,000	2.9023	29,023.00	10000	2.5225	25,225.00	-3,798.00	(13.1)%	4.36%
Global Adjustment Rate Rider	10,000	0.7109	7,109.00	10,000	0.7109	7,109.00	0.00	0.0%	1.23%
Distribution Volumetric Rate Rider (2011) Group 2	10,000	0.0000	0.00	10,000	0.1574	1,574.00	1,574.00	0.0%	0.27%
LRAM Volumetric Rate Rider (2011)	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	10,000	-1.0611	-10,611.00	10,000	-1.0611	-10,611.10	-0.10	0.0%	-1.83%
TX Allowance $0.60/kw	10,000	-0.6000	-6,000.00	10,000	0.0000	0.00	6,000.00	(100.0)%	0.00%
Total: Distribution			**24,244.33**			**28,506.23**	**4,261.90**	**17.6%**	**4.93%**
Retail Transmission Rate – Network Service Rate	10,000	2.7045	27,045.00	10,000	2.7045	27,045.00	0.00	0.0%	4.67%
Retail Transmission Rate – Line and Transformation Connection	10,000	2.1088	21,088.00	10,000	2.1088	21,088.00	0.00	0.0%	3.64%
Retail Transmission Rate – Low Voltage Volumetric Rate	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**48,133.00**			**48,133.00**	**0.00**	**0.0%**	**8.32%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**72,377.33**			**76,639.23**	**4,261.90**	**5.9%**	**13.24%**
Wholesale Market Service Rate	5,231,436	0.0056	29,296.04	5,231,436	0.0056	29,296.04	0.00	0.0%	5.06%
Rural Rate Protection Charge	5,231,436	0.0013	6,800.87	5,231,436	0.0013	6,800.87	0.00	0.0%	1.18%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**36,097.16**			**36,097.16**	**0.00**	**0.0%**	**6.24%**
Debt Retirement Charge (DRC)	5,208,000	0.0070	**36,456.00**	5,208,000	0.0070	**36,456.00**	**0.00**	**0.0%**	**6.30%**
Total Bill before Taxes			**507,887.52**			**512,149.42**	**4,261.90**	**0.8%**	**88.50%**
GST	507,887.52	13%	**66,025.38**	512,149.42	13%	**66,579.42**	**554.04**	**0.8%**	**11.50%**
Total Bill			**573,912.90**			**578,728.84**	**4,815.94**	**0.8%**	**100.00%**

Table 22: Large Use

Consumption	**7,812,000**	**kWh**	**15,000**	**kW**		***Loss Factor Old***	***1.0045***		
RPP Tier One	**750**	**kWh**	***Load Factor***	***70.0%***		***Loss Factor New***	***1.0045***		

Large Use	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.01%
Energy Second Tier (kWh)	7,846,404	0.0694	544,383.51	7,846,404	0.0694	544,383.51	0.00	0.0%	62.92%
Sub-Total: Energy			**544,435.55**			**544,435.55**	**0.00**	**0.0%**	**62.93%**
Service Charge	1	4,722.33	4,722.33	1	5,208.02	5,208.02	485.69	10.3%	0.60%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.00%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	15,000	2.9023	43,534.50	15000	2.5225	37,837.50	-5,697.00	(13.1)%	4.37%
Global Adjustment Rate Rider	15,000	0.7109	10,663.50	15,000	0.7109	10,663.50	0.00	0.0%	1.23%
Distribution Volumetric Rate Rider (2011) Group 2	15,000	0.0000	0.00	15,000	0.1574	2,361.00	2,361.00	0.0%	0.27%
LRAM Volumetric Rate Rider (2011)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	15,000	-1.0611	-15,916.50	15,000	-1.0611	-15,916.65	-0.15	0.0%	-1.84%
TX Allowance $0.60/kw	15,000	-0.6000	-9,000.00	15,000	0.0000	0.00	9,000.00	(100.0)%	0.00%
Total: Distribution			**34,004.83**			**40,154.68**	**6,149.85**	**18.1%**	**4.64%**
Retail Transmission Rate – Network Service Rate	15,000	2.7045	40,567.50	15,000	2.7045	40,567.50	0.00	0.0%	4.69%
Retail Transmission Rate – Line and Transformation Connection	15,000	2.1088	31,632.00	15,000	2.1088	31,632.00	0.00	0.0%	3.66%
Retail Transmission Rate – Low Voltage Volumetric Rate	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**72,199.50**			**72,199.50**	**0.00**	**0.0%**	**8.35%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**106,204.33**			**112,354.18**	**6,149.85**	**5.8%**	**12.99%**
Wholesale Market Service Rate	7,847,154	0.0056	43,944.06	7,847,154	0.0056	43,944.06	0.00	0.0%	5.08%
Rural Rate Protection Charge	7,847,154	0.0013	10,201.30	7,847,154	0.0013	10,201.30	0.00	0.0%	1.18%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**54,145.61**			**54,145.61**	**0.00**	**0.0%**	**6.26%**
Debt Retirement Charge (DRC)	7,812,000	0.0070	**54,684.00**	7,812,000	0.0070	**54,684.00**	**0.00**	**0.0%**	**6.32%**
Total Bill before Taxes			**759,469.49**			**765,619.34**	**6,149.85**	**0.8%**	**88.50%**
GST	759,469.49	13%	**98,731.03**	765,619.34	13%	**99,530.51**	**799.48**	**0.8%**	**11.50%**
Total Bill			**858,200.52**			**865,149.85**	**6,949.33**	**0.8%**	**100.00%**

Table 23: Large Use

Consumption	**10,416,000**	**kWh**	**20,000**	**kW**		***Loss Factor Old***	***1.0045***		
RPP Tier One	**750**	**kWh**	***Load Factor***	***70.0%***		***Loss Factor New***	***1.0045***		

Large Use	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.00%
Energy Second Tier (kWh)	10,462,122	0.0694	725,862.02	10,462,122	0.0694	725,862.02	0.00	0.0%	63.03%
Sub-Total: Energy			**725,914.06**			**725,914.06**	**0.00**	**0.0%**	**63.04%**
Service Charge	1	4,722.33	4,722.33	1	5,208.02	5,208.02	485.69	10.3%	0.45%
Service Charge Rate Adder(s) Smart Meter	1	1.00	1.00	1	1.03	1.03	0.03	3.0%	0.00%
Service Charge Rate Rider(s) Late Payment				1	0.28	0.28	0.28	0.0%	0.00%
Distribution Volumetric Rate	20,000	2.9023	58,046.00	20000	2.5225	50,450.00	-7,596.00	(13.1)%	4.38%
Global Adjustment Rate Rider	20,000	0.7109	14,218.00	20,000	0.7109	14,218.00	0.00	0.0%	1.23%
Distribution Volumetric Rate Rider (2011) Group 2	20,000	0.0000	0.00	20,000	0.1574	3,148.00	3,148.00	0.0%	0.27%
LRAM Volumetric Rate Rider (2011)	20,000	0.0000	0.00	20,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	20,000	-1.0611	-21,222.00	20,000	-1.0611	-21,222.20	-0.20	0.0%	-1.84%
TX Allowance $0.60/kw	20,000	-0.6000	-12,000.00	20,000	0.0000	0.00	12,000.00	(100.0)%	0.00%
Total: Distribution			**43,765.33**			**51,803.13**	**8,037.80**	**18.4%**	**4.50%**
Retail Transmission Rate – Network Service Rate	20,000	2.7045	54,090.00	20,000	2.7045	54,090.00	0.00	0.0%	4.70%
Retail Transmission Rate – Line and Transformation Connection	20,000	2.1088	42,176.00	20,000	2.1088	42,176.00	0.00	0.0%	3.66%
Retail Transmission Rate – Low Voltage Volumetric Rate	20,000	0.0000	0.00	20,000	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**96,266.00**			**96,266.00**	**0.00**	**0.0%**	**8.36%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**140,031.33**			**148,069.13**	**8,037.80**	**5.7%**	**12.86%**
Wholesale Market Service Rate	10,462,872	0.0056	58,592.08	10,462,872	0.0056	58,592.08	0.00	0.0%	5.09%
Rural Rate Protection Charge	10,462,872	0.0013	13,601.73	10,462,872	0.0013	13,601.73	0.00	0.0%	1.18%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**72,194.06**			**72,194.06**	**0.00**	**0.0%**	**6.27%**
Debt Retirement Charge (DRC)	10,416,000	0.0070	**72,912.00**	10,416,000	0.0070	**72,912.00**	**0.00**	**0.0%**	**6.33%**
Total Bill before Taxes			**1,011,051.45**			**1,019,089.25**	**8,037.80**	**0.8%**	**88.50%**
GST	1,011,051.45	13%	**131,436.69**	1,019,089.25	13%	**132,481.60**	**1,044.91**	**0.8%**	**11.50%**
Total Bill			**1,142,488.14**			**1,151,570.85**	**9,082.71**	**0.8%**	**100.00%**

Table 24: Street Lighting

Consumption	**2,010,000**	**kWh**	**6,700**	**kW**		***Loss Factor Old***	***1.0356***		
RPP Tier One	**750**	**kWh**				***Loss Factor New***	***1.0349***		
Street Lighting	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	750	0.0694	52.04	750	0.0694	52.04	0.00	0.0%	0.01%
Energy Second Tier (kWh)	2,080,806	0.0694	144,366.32	2,079,399	0.0694	144,268.70	-97.62	(0.1)%	41.37%
Sub-Total: Energy			**144,418.36**			**144,320.74**	**-97.62**	**(0.1)%**	**41.39%**
Service Charge Connections	0	0.00	0.00	18000	1.3400	24,120.00	24,120.00	0.0%	6.92%
Service Charge Rate Adder(s)	0	0.00	0.00	0	0.00	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate	6,700	2.2046	14,770.82	6700	13.6018	91,132.06	76,361.24	517.0%	26.13%
Global Adjustment Rate Rider	6,700	0.4461	2,988.94	6,700	0.4461	2,988.94	0.00	0.0%	0.86%
Distribution Volumetric Rate Rider (2011) Group 2	6,700	0.0000	0.00	6,700	0.1074	719.58	719.58	0.0%	0.21%
LRAM Volumetric Rate Rider (2011)	6,700	0.0000	0.00	6,700	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	6,700	-0.6678	-4,474.26	6,700	-0.6678	-4,474.26	0.00	0.0%	-1.28%
Total: Distribution			**13,285.50**			**114,486.32**	**101,200.82**	**761.7%**	**32.83%**
Retail Transmission Rate – Network Service Rate	6,700	1.7741	11,886.47	6,700	1.7741	11,886.47	0.00	0.0%	3.41%
Retail Transmission Rate – Line and Transformation Connection	6,700	1.4130	9,467.10	6,700	1.4130	9,467.10	0.00	0.0%	2.71%
Retail Transmission Rate – Low Voltage Volumetric Rate	6,700	0.0000	0.00	6,700	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**21,353.57**			**21,353.57**	**0.00**	**0.0%**	**6.12%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**34,639.07**			**135,839.89**	**101,200.82**	**292.2%**	**38.96%**
Wholesale Market Service Rate	2,081,556	0.0056	11,656.71	2,080,149	0.0056	11,648.83	-7.88	(0.1)%	3.34%
Rural Rate Protection Charge	2,081,556	0.0013	2,706.02	2,080,149	0.0013	2,704.19	-1.83	(0.1)%	0.78%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.00%
Sub-Total: Regulatory			**14,362.98**			**14,353.27**	**-9.71**	**(0.1)%**	**4.12%**
Debt Retirement Charge (DRC)	2,010,000	0.0070	**14,070.00**	2,010,000	0.0070	**14,070.00**	**0.00**	**0.0%**	**4.03%**
Total Bill before Taxes			**207,490.41**			**308,583.90**	**101,093.49**	**48.7%**	**88.50%**
GST	207,490.41	13%	**26,973.75**	308,583.90	13%	**40,115.91**	**13,142.16**	**48.7%**	**11.50%**
Total Bill			**234,464.16**			**348,699.81**	**114,235.65**	**48.7%**	**100.00%**

Table 25: USL

Consumption	**1,000**	**kWh**	***Loss Factor Old***			**1.0356**			
RPP Tier One	**750**	**kWh**	***Loss Factor New***			**1.0349**			
General Service USL	**Volume**	**RATE $**	**CHARGE $**	**Volume**	**RATE $**	**CHARGE $**	**$**	**%**	**% of Total Bill**
Energy First Tier (kWh)	500	0.0650	32.50	500	0.0650	32.50	0.00	0.0%	30.65%
Energy Second Tier (kWh)	0	0.0750	0.00	0	0.0750	0.00	0.00	0.0%	0.00%
Sub-Total: Energy			**32.50**			**32.50**	**0.00**	**0.0%**	**30.65%**
Service Charge / Connections	1	20.15	20.15	13	1.21	15.73	-4.42	(21.9)%	14.84%
Service Charge Rate Adder(s) Smart Meter	1	0.00	0.00	1	0.00	0.00	0.00	0.0%	0.00%
Service Charge Rate Rider(s) Late Payment	1	0.00	0.00	1	0.00	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate	1,000	0.0178	17.80	1,000	0.0222	22.20	4.40	24.7%	20.94%
Distribution Volumetric Rate Rider (2011) Group 2	1,036	0.0000	0.00	1,035	0.0008	0.83	0.83	0.0%	0.78%
LRAM Volumetric Rate Rider (2011)	1,000	0.0000	0.00	1,000	0.0000	0.00	0.00	0.0%	0.00%
Distribution Volumetric Rate Rider (2010) Group 1	1,036	-0.0020	-2.07	1,035	-0.0020	-2.07	0.00	0.0%	-1.95%
Total: Distribution			**35.88**			**36.69**	**0.81**	**2.3%**	**34.60%**
Retail Transmission Rate – Network Service Rate	1,036	0.0055	5.70	1,035	0.0055	5.69	-0.01	(0.2)%	5.37%
Retail Transmission Rate – Line and Transformation Connection	1,036	0.0044	4.56	1,035	0.0044	4.55	-0.01	(0.2)%	4.29%
Retail Transmission Rate – Low Voltage Volumetric Rate	1,036	0.0000	0.00	1,035	0.0000	0.00	0.00	0.0%	0.00%
Total: Retail Transmission			**10.26**			**10.24**	**-0.02**	**(0.2)%**	**9.66%**
Sub-Total: Delivery (Distribution and Retail Transmission)			**46.14**			**46.93**	**0.79**	**1.7%**	**44.26%**
Wholesale Market Service Rate	1,036	0.0056	5.80	1,035	0.0056	5.80	0.00	0.0%	5.47%
Rural Rate Protection Charge	1,036	0.0013	1.35	1,035	0.0013	1.35	0.00	0.0%	1.27%
Standard Supply Service – Administration Charge (if applicable)	1	0.25	0.25	1	0.25	0.25	0.00	0.0%	0.24%
Sub-Total: Regulatory			**7.40**			**7.40**	**0.00**	**0.0%**	**6.98%**
Debt Retirement Charge (DRC)	1,000	0.0070	**7.00**	1,000	0.0070	**7.00**	**0.00**	**0.0%**	**6.60%**
Total Bill before Taxes			**93.04**			**93.83**	**0.79**	**0.8%**	**88.49%**
GST	93.04	13%	**12.10**	93.83	13%	**12.20**	**0.10**	**0.8%**	**11.51%**
Total Bill			**105.14**			**106.03**	**0.89**	**0.8%**	**100.00%**

REVENUE PER RATE CLASS AT CURRENT & PROPOSED RATES

The following table provides a comparison of Revenue Per Customer class based on 2011forecast billing determinant throughput quantities at existing rates, at proposed rates and finally based on expected Base Revenue Requirement.

Table 1: Revenue at Existing Rates, Expected Revenue, and Revenue at Proposed Rates

Customer Class	Throughput Distribution Revenue At Existing Rates	Revenue Requirement Expected by Customer Class	Difference - Existing vs Proposed	Throughput Distribution Revenue At Proposed Rates	Difference - Proposed vs Expected
Residential	$32,611,130	$33,931,976	$1,320,846	$33,913,877	($18,099)
GS < 50 kW	$7,083,429	$6,619,012	($464,417)	$6,609,534	($9,478)
GS > 50 to 699 kW	$8,764,421	$10,468,422	$1,704,001	$10,468,409	($13)
GS > 700 to 4,999 kW	$7,861,805	$7,430,218	($431,588)	$7,430,227	$9
Large Use	$1,935,349	$2,134,304	$198,955	$2,134,272	($32)
Street Lighting	$194,594	$1,883,530	$1,688,936	$1,883,527	($3)
Unmetered Scattered Load	$102,209	$127,882	$25,672	$127,659	($223)
Total	$58,552,937	$62,595,343	$4,042,406	$62,567,504	($27,839)

2011 Forecast throughput revenues at existing rates would be $58,552,937 as compared to the requested Revenue Requirement expected to be $62,595,343 with the difference of $4,042,406 which is equivalent to the Revenue Deficiency calculated for the 2011 test year. When the rates are calculated then rounded as shown in the Tariff of Rates and Charges this rounding does not permit HOBNI to recover of the exact amount of the Revenue Deficiency. There is a rounding difference of $27,839.

DETAILED RECONCILIATION OF RATE CLASS REVENUE TO REVENUE REQUIREMENT

Table 1 provides a reconciliation between the 2011 distribution rate calculations based on the 2011 Proposed Rates at forecast throughput billing determinants and the total base revenue required. The approved Service Charge (fixed monthly) is either applied on a per customer or per connection basis. These Service Charges are presented in the Tariff of Rates and Charges to two decimal places. The Distribution Volumetric Rate is applied to either the kWh consumption or the Peak Monthly Demand depending on the customer class. These charges are presented in the Tariff of Rates and Charges to 4 decimal places. When rates are established in the HOBNI Rate Design Model the full revenue requirement is allocated to customer classes assuming the full amount will be recovered through rates with no rounding. When Rates are rounded as presented in the Tariff of Rates and Charges and multiplied by the forecast annual throughput quantities a rounding difference is created. The difference below of $27,839 is the result of this rounding. HOBNI rounded the Service Charges up in order to minimize the difference due to rounding.

Table 1: 2011 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue	Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected
Residential	$ 16,189,564	$ 17,724,313		$ 33,913,877	$ 33,931,976
GS < 50 kW	$ 1,783,492	$ 4,826,042		$ 6,609,534	$ 6,619,012
GS > 50 to 699 kW	$ 2,259,588	$ 8,398,634	($189,813)	$ 10,468,409	$ 10,468,422
GS > 700 to 4,999 kW	$ 1,694,714	$ 7,119,608	($1,384,095)	$ 7,430,227	$ 7,430,218
Large Use	$ 374,952	$ 1,759,320	$0	$ 2,134,272	$ 2,134,304
Street Lighting	$ 677,904	$ 1,205,623		$ 1,883,527	$ 1,883,530
Unmetered Scattered Load	$ 18,882	$ 108,777		$ 127,659	$ 127,882
Total	**$ 22,999,095**	**$ 41,142,317**	**($1,573,908)**	**$ 62,567,504**	**$ 62,595,343**

Difference Due to Rate Rounding
$ 27,839

RATE MITIGATION PLAN

In preparing this Application, Hydro One Brampton has considered the rate impacts associated with changes to rate base, increased ROE and the various rate adders on its customers. . Hydro One Brampton's proposal includes the continuance of the disposition of Deferral and Variance Account associated with Group 1 balances along with the commencement of a new disposition rider of Group 2 accounts.

Hydro One Brampton submits that the bill impacts associated with its proposed 2011 electricity distribution rates including rate riders are reasonable and are not significant enough to warrant any mitigation measures. For the Street Light rate class, the bill impacts are above 10% resulting from the implementation of the recent cost allocation study. Hydro One Brampton has proposed to move this customer class to the OEB's staff recommended minimum Revenue to Cost ratio. As a result, this class will experience higher increases than other customer classes.

In a further attempt to mitigate customer rate increases, Hydro One Brampton is requesting that the Rate Riders associated with the disposition of Group 2 Deferral and Variance Account, and LRAM recoveries occur over a two year period.

CUSTOMER IMPACT

In preparing this application, Hydro One Brampton has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, most customer classes have been adjusted closer to a unity Revenue to Cost ratio with marginal customer impacts to overall bill increases.

For the Street Light rate class, the bill impacts are above 10% resulting from the implementation of the recent cost allocation study. Hydro One Brampton has proposed to move this customer class to the OEB's staff recommended minimum Revenue to Cost ratio. As a result, this class will experience higher increases than other customer classes

As a result of the cost allocation study the Street Light class will be contributing more distribution revenue to the cost pool in 2011. This will slightly offset the distribution revenue required from the other classes. This will help to mitigate some of the other rate increases to the other classes.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates [monthly service charge and volumetric rates], revised loss factors, LRAM/SSM rate riders, Smart Meter rate rider and rate adder, and regulatory asset rate riders to dispose of the balances in the Deferral and Variance Accounts requested in this Application are set out in the table below

Table 1: Requested Deferral and Variance Accounts

Class – Typical Usage	Monthly Dollar Impact	Total Bill Impact %
Residential - 800 kWh/mth		
Comparison to 2010	$ 3.43	3.06%
General Service < 50 kW - 2,000 kWh/mth		
Comparison to 2010	-$ 1.84	-0.65%
General Service 50 to 699 kW 184 kW 68,500 kWh/mth		
Comparison to 2010	$ 138.79	1.74%
General Service 700 - 4,999 857 kW 500,000 kWh/mth		
Comparison to 2010	$ 143.01	0.25%
Large Use > 5,000 6,000 kW 3,100,000 kWh/mth		
Comparison to 2010	$ 3,109.24	0.90%
Street Light		
Comparison to 2010	$ 114,235.65	48.72%
USL		
Comparison to 2010	$ 0.89	0.85%

SPECIFIC SERVICE CHARGES

Hydro One Brampton is not seeking any additions or changes to the current Board Approved Specific Service Charges.

EXISTING SCHEDULE OF TARIFFS AND CHARGES

Hydro One Brampton's existing Schedule of Tariffs and Charges is provided in the following pages.

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account where the electricity is used supplied exclusively to single-family dwelling units for domestic or household purposes, including seasonal occupancy. This includes, but is not limited to, detached houses, one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex also qualify as residential 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 or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	10.60
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0154
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0020)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification applies to a non residential account less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall normally be classified as general service.

Where service is provided to combined residential and business, or residential and agricultural, whether seasonal or all-year premises, and the wiring does not provide for separate metering, the service shall normally be classed as general service.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	20.27
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kWh	0.0178
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0020)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

GENERAL SERVICE 50 to 699 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 700 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	101.68
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kW	2.2935
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.4861
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(0.7321)
Retail Transmission Rate – Network Service Rate	$/kW	2.1307
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6973

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

GENERAL SERVICE 700 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 700 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1,410.45
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kW	3.7355
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.5881
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(0.8881)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.3896
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8245

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand over 12 consecutive months used for billing purposes is equal to or greater than 5,000 kW, or is forecast to be equal to or greater than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	4,722.33
Smart Meter Funding Adder	$	1.00
Distribution Volumetric Rate	$/kW	2.9023
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.7109
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(1.0611)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.7045
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1088

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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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, 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.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	20.15
Distribution Volumetric Rate	$/kWh	0.0178
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0020)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	1.5047

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

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.

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MONTHLY RATES AND CHARGES – Delivery Component

Distribution Volumetric Rate	$/kW	3.7988
Retail Transmission Rate – Network Service Rate	$/kW	1.7764
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4148

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

STREET LIGHTING SERVICE CLASSIFICATION

All service supplied to roadway lighting equipment owned by or operated by the City of Brampton, Regional Municipality of Peel, or the Ministry of Transportation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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MONTHLY RATES AND CHARGES – Delivery Component

Distribution Volumetric Rate	$/kW	2.2046
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kW	0.4461
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(0.6678)
Retail Transmission Rate – Network Service Rate	$/kW	1.7741
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4130

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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MONTHLY RATES AND CHARGES – Delivery Component – effective September 21, 2009

Service Charge	$	5.25

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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MONTHLY RATES AND CHARGES

Distribution Wheeling Service Rate	$/kW	0.0612

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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ALLOWANCES

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

SPECIFIC SERVICE CHARGES

APPLICATION

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Customer Administration		
Arrears certificate	$	15.00
Pulling post dated Cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Special Billing Service (aggregation)	$	125.00
Special Billing Service (sub-metering charge per meter)	$	25.00

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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1	Non-Payment of Account		
2	Late Payment - per month	%	1.50
3	Late Payment - per annum	%	19.56
4	Collection of account charge - no disconnection	$	30.00
5	Disconnect/Reconnect at meter - during regular hours	$	65.00
6	Disconnect/Reconnect at meter - after regular hours	$	185.00
7	Disconnect/Reconnect at pole - during regular hours	$	185.00
8	Disconnect/Reconnect at pole - after regular hours	$	415.00
9	Disconnect/Reconnection for >300 volts - during regular hours	$	60.00
10	Disconnect/Reconnection for >300 volts - after regular hours	$	155.00
11	Owner Requested Disconnection/Reconnection - during regular hours	$	120.00
12	Owner Requested Disconnection/Reconnection - after regular hours	$	155.00
13	Specific Charge for Access to the Power Poles - per pole/year	$	22.35

Hydro One Brampton Networks Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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

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	1.0356
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0253
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

PROPOSED SCHEDULE OF TARIFFS AND CHARGES

Hydro One Brampton's proposed Schedule of Tariffs and Charges is provided in the following pages.

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account where the electricity is used supplied exclusively to single-family dwelling units for domestic or household purposes, including seasonal occupancy. This includes, but is not limited to, detached houses, one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex also qualify as residential 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 or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	11.27
Smart Meter Funding Adder	$	1.03
Late Payment Recovery – effective until December 31, 2011	$	0.28
Distribution Volumetric Rate	$/kWh	0.0160
Rate Rider for LRAM/SSM Recovery – effective until December 31, 2012	$/kWh	0.0010
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider #1 for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0020)
Rate Rider #2 for Deferral/Variance Account Disposition (2011) – effective until December 31, 2012	$/kWh	0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.

PROPOSED TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Multi-unit residential establishments such as apartment buildings supplied through one service (bulk metered) shall normally be classified as general service.

Where service is provided to combined residential and business, or residential and agricultural, whether seasonal or all-year premises, and the wiring does not provide for separate metering, the service shall normally be classed as general service.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	19.19
Smart Meter Funding Adder	$	1.03
Late Payment Recovery – effective until December 31, 2011	$	0.28
Distribution Volumetric Rate	$/kWh	0.0166
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider #1 for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0020)
Rate Rider #2 for Deferral/Variance Account Disposition (2011) – effective until December 31, 2012	$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

GENERAL SERVICE 50 TO 699 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 700 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	121.67
Smart Meter Funding Adder	$	1.03
Late Payment Recovery – effective until December 31, 2011	$	0.28
Distribution Volumetric Rate	$/kW	2.7269
Rate Rider for LRAM/SSM Recovery – effective until December 31, 2012	$/kW	0.0079
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.4861
Rate Rider #1 for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(0.7321)
Rate Rider #2 for Deferral/Variance Account Disposition (2011) – effective until December 31, 2012	$/kW	0.1357
Retail Transmission Rate – Network Service Rate	$/kW	2.1307
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6973

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

GENERAL SERVICE 700 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 700 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	1,333.27
Smart Meter Funding Adder	$	1.03
Late Payment Recovery – effective until December 31, 2011	$	0.28
Distribution Volumetric Rate	$/kW	3.7887
Rate Rider for LRAM/SSM Recovery – effective until December 31, 2012	$/kW	0.0378
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.5881
Rate Rider #1 for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(0.8881)
Rate Rider #2 for Deferral/Variance Account Disposition (2011) – effective until December 31, 2012	$/kW	0.1778
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.3896
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8245

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand over 12 consecutive months used for billing purposes is equal to or greater than 5,000 kW, or is forecast to be equal to or greater than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5,208.02
Smart Meter Funding Adder	$	1.03
Late Payment Recovery – effective until December 31, 2011	$	0.28
Distribution Volumetric Rate	$/kW	2.5225
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.7109
Rate Rider #1 for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(1.0611)
Rate Rider #2 for Deferral/Variance Account Disposition (2011) – effective until December 31, 2012	$/kW	0.1574
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.7045
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1088

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

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, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.21
Distribution Volumetric Rate	$/kWh	0.0222
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012		
Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider #1 for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.0020)
Rate Rider #2 for Deferral/Variance Account Disposition (2011) – effective until December 31, 2012	$/kWh	0.0008
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0044

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

STANDBY POWER SERVICE CLASSIFICATION

This classification refers to an account that has Load Displacement Generation and requires the distributor to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).	$/kW	1.5047

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

STREET LIGHTING SERVICE CLASSIFICATION

All service supplied to roadway lighting equipment owned by or operated by the City of Brampton, Regional Municipality of Peel, or the Ministry of Transportation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.34
Distribution Volumetric Rate	$/kW	13.6018
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kW	0.4461
Rate Rider #1 for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kW	(0.6678)
Rate Rider #2 for Deferral/Variance Account Disposition (2011) – effective until December 31, 2012	$/kW	0.1074
Retail Transmission Rate – Network Service Rate	$/kW	1.7741
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4130

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES

Distribution Wheeling Service Rate	$/kW	0.0612

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

ALLOWANCES

Transformer Allowance for Ownership		
General Service 50 to 699 kW- per kW of billing demand/month	$/kW	(0.7202)
General Service 700 to 4,999 kW - per kW of billing demand/month	$/kW	(0.8952)
Primary Metering Allowance for transformer losses – applied to measured demand and energy		%(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration

Arrears certificate	$	15.00
Pulling post dated Cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Special Billing Service (aggregation)	$	125.00
Special Billing Service (sub-metering charge per meter)	$	25.00

Non-Payment of Account

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

Hydro One Brampton Networks Inc.
PROPOSED TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2011

Non-Payment of Account – Continued

Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Disconnect/Reconnection for >300 volts - during regular hours	$	60.00
Disconnect/Reconnection for >300 volts - after regular hours	$	155.00
Owner Requested Disconnection/Reconnection - during regular hours	$	120.00
Owner Requested Disconnection/Reconnection - after regular hours	$	155.00
Specific Charge for Access to the Power Poles - per pole/year	$	22.35

RETAIL SERVICE CHARGES (IF APPLICABLE)

APPLICATION

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

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

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

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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

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

Hydro One Brampton Networks Inc.

PROPOSED TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2011

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	1.0349
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0247
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045