DISTRIBUTION LINE LOSS

1.0 INTRODUCTION

This exhibit presents a discussion on the types of line loss, the reason they exist, an estimate of the technical and non-technical line loss associated with Hydro One's Distribution System as a whole, recommended Distribution Loss Factors and how Hydro One manages distribution line loss.

The term "distribution line losses" refers to the difference between the amount of energy delivered to the distribution system and the amount of energy customers are billed. Distribution line losses are comprised of two types: technical and non-technical (the description of each type is presented in the sections below).

It is important to know the magnitude and causality factors for line losses because the cost of energy lost is recovered from customers.

As a result of the composition and scale of the Hydro One distribution system it is not economic to provide metering and the supporting processes capable of measuring line loses directly. Since energy meters do not total data for the same periods, as load varies over time a direct measurement of actual losses is not feasible. Instead, Hydro One relies on studies which, are designed to calculate the magnitude, composition and distribution of system losses based on annual aggregate metering information for energy purchases, energy sales and system modeling methods. These studies are conducted with the assistance of industry experts in this field to ensure appropriate scientific methods and modeling techniques are utilized in establishing the magnitude, composition and distribution of losses.

2.0 TECHNICAL LOSSES

Technical losses on distribution systems are primarily due to heat dissipation resulting from current passing through conductors and from magnetic losses in transformers. Losses are inherent to the distribution of electricity and cannot be eliminated.

Hydro One issued a Request for Proposals (RFP) to carry out an independent assessment of technical losses on Hydro One's distribution system. After evaluating proposals from several bidders, the work was awarded to Kinectrics Inc. because the company provided an economic proposal and is a world renowned Research and Development company recognized as a leading authority on Distribution Systems and distribution losses in particular.

The report prepared by Kinectrics and entitled "Distribution System Energy Losses at Hydro One" is presented in Appendix A of this Exhibit.

This report forms the basis for Hydro One's statements on the magnitude, composition and distribution of losses on the System. The report establishes the Distribution Loss Factors (DLFs) for the various customer groups and also provides the rationale and recommendations for Hydro One's distribution loss reduction program.

Hydro One owns primarily a rural distribution system with some pockets of urban development. Hydro One's distribution system technical losses are estimated to be 5.65 percent of the energy delivered to the distribution system and consist of estimated 5.05 percent for losses incurred in the distribution system and 0.6 percent of losses that relate to transformer losses

Losses occur on subtransmission lines, distribution lines, station transformers, distribution transformers and secondary services to customers. Transformer losses include no-load losses that are independent of transformer loading and load losses that are dependent on the loading.

2.1 Comparison of Typical Urban vs Rural Losses

The loss breakdown by power system components for the distribution system of typical urban and rural utilities is shown in the table below. Typical urban area loss is 3.6 percent of energy sold and can range from 2 percent to 5 percent. Typical rural area loss is 7.3 percent of energy sold and can range from 4 percent to 10 percent.

Typical Urban vs. Rural Losses

Component	**Estimated Loss as a Percentage of Energy Sold**	
	Typical Urban	**Typical Rural**
Subtransmission lines	0.1	0.7
Power transformers	0.1	0.7
Distribution lines	0.9	2.5
Distribution transformers no load	1.2	1.7
Distribution transformers load	0.8	0.8
Secondary lines	0.5	0.9
Total	3.6	7.3

2.2 Hydro One Losses Estimate

The estimated Hydro One’s distribution system losses as estimated by the Kinectrics study presented in Appendix A are summarized in the table below.

Hydro One Losses Estimate

Component	**Estimated Loss as a Percent of Energy Sold**
Subtransmission lines	2.33
Power transformers no load	0.21
Power transformers load	0.12
Distribution lines	1.18
Distribution transformers no load	0.78
Distribution transformers load	0.19
Secondary lines	0.24
Total	**5.05**

* Note: This table does not include transformation losses (0.6%) that are included in Hydro One's Total Distribution Loss Factors.

The total annual energy loss in Hydro One's distribution system is estimated to be about 5.05 percent of the energy sales (excluding 0.6 percent for transformation losses). This is in line with typical losses incurred by other utilities considering Hydro One's mix of rural and urban customers.

3.0 NON-TECHNICAL LOSSES

Non-technical losses occur as a result of theft, metering inaccuracies and unmetered energy. The following sections are a discussion on each of these items.

3.1 Theft of Power Losses

Theft of power is energy delivered to customers that is not measured by the energy meter for the customer. This can happen as a result of meter tampering or by bypassing the meter.

Hydro One manages theft of power by inspection of the meter for tampering or bypassing during meter reading activities, monitoring anomalies during bill preparation and in cooperation with police activities.

3.2 Metering Inaccuracies Losses

Losses due to metering inaccuracies are defined as the difference between the amount of energy actually delivered through the meters and the amount registered by the meters. All energy meters have some level of error which requires that standards be established. Industry Canada is responsible for regulating energy meter accuracy.

Hydro One manages energy losses due to metering inaccuracies through a meter accuracy verification program.

3.3 Unmetered Losses

Unmetered losses are situations where the energy usage is estimated instead of measured with an energy meter. This happens when the loads are very small and energy meter installation is economically impractical. Examples of this are street lights and cable television amplifiers.

3.4 Estimate of Non-Technical Losses

Non-technical losses have been established by reviewing losses from theft, meter inaccuracies and unmetered energy in other jurisdictions. Based on the Kinectrics overview of the non-technical losses value from utilities across North America, United Kingdom and Australia, a value of 1.2% was recommended as a reasonable estimate.

4.0 LOSS ALLOCATION

To appropriately allocate the cost of losses to the different classes of distribution customers, it is necessary to estimate the losses in Hydro One's distribution system attributable to sub-transmission, primary distribution and secondary distribution sub-systems.

Within each of the Sub-Transmission, Primary Distribution and Secondary Distribution classes of customers, there are differences among the losses incurred by customers in relation to the energy used. For example, delivering electricity to a Retail customer at the end of a long secondary distribution line would entail more loss than a customer using the same amount of electricity upstream on that line.

Although different customers will have characteristically different loss factors, individual customers are not billed by individual loss factors. It is not practical to accurately measure or to model each specific customer's loss factor. Therefore, customers are allocated losses based on the losses incurred by all similar customers in a group, and they are billed a Distribution Loss Factor (DLF) based on the losses incurred by that entire group.

The estimated values for the DLF for each of the customer classes are based on the Kinectrics study presented in Appendix A of this Exhibit.

4.1 Sub-transmission System Customers Class

To serve sub-transmission class customers, electricity flows through sub-transmission feeders, which operate at relatively high voltage levels that range between nominal voltages of 44kV and 13.8 kV. Since lines operating at higher voltage levels experience less energy loss per amount of energy delivered than lower voltage lines, serving sub-transmission class customers generally involves lower losses as a percent of energy delivered, compared to customers served from lower voltage facilities.

4.2 Primary Distribution Customers Class

These customers are connected to primary distribution lines, which function at voltage levels ranging between 12.5 kV and 2.4 kV. At these lower voltages, primary distribution lines generally lose more energy (per length of line) than sub-transmission lines. Moreover, most Intermediate class customers are served through Low Voltage Distributing Stations (LVDS), who in turn receive supply from the sub-transmission system further upstream. Energy is lost within both the LVDS transformers and in the lines emanating from them. This results in more energy lost per amount delivered to this Intermediate class of customers than to Sub-transmission customers.

4.3 Secondary Distribution Customers Class

These customers receive electricity after it has passed through several stages of transformation before being sent at low voltage through secondary distribution lines that operate at voltages around 120V. Pole-top, pad-mount and underground step-down transformers that step-down voltage from primary distribution system to the secondary distribution system generally lose more energy per quantity delivered than do transformer stations or HVDS's. The pole-top, pad-mount and underground transformers function at much lower load factors because they serve less diverse groupings of lower-volume customers (e.g. a small number of residences). Therefore, they often operate at little or no load, though still drawing power for their operation thus sustaining relatively high losses per energy delivered. In addition to all the losses associated with the transformation to the secondary voltage, the secondary distribution lines themselves lose a substantial amount of energy per unit delivered.

The total losses attributable to the Secondary Distribution Customers Class also include the losses in the sub-transmission and primary distribution systems upstream in the delivery chain. As a result, retail customers generally incur higher losses per unit delivered than any other customer class.

4.4 Comparison of the Estimated DLFs with the DLFs in the Existing Rate

The table below compares DLFs in the existing rate with the ones estimated in the Kinectrics study for the three customer classes.

Customer Type	Total DLF in Present Rates	Total Estimated DLF
Embedded LDC and Subtransmission Customers	3.4%	4.4 %
Primary Customers	6.1%	6.8%
Secondary Customers	9.2%	9.6%

The losses in the table include technical and non-technical losses in the distribution system and 0.6% for transformation losses.

For all the customer classes the DLFs based on the Kinectrics study results are higher than the DLFs included in the existing rate. To mitigate financial impact on the future rates to the extent possible, Hydro One utilizes a number of approaches to reduce the losses as a general business practice as described in the section below. In addition, Hydro One is also planning to implement a specific loss management initiative summarized in the section below with the more detailed description provided in the Kinectrics report included in Appendix A of this exhibit.

5.0 HYDRO ONE LOSS MANAGEMENT

5.1 General Practices

Hydro One manages losses in the following ways, where it is cost-effective:

[1] Technical evaluation of projects - Presently, when Hydro One evaluates projects, the incremental cost of mitigating losses is considered among the options. If two projects are close in cost, the option that will result in lower losses may be a deciding factor. Standard planning practices include the developing options, which would reduce system losses. This includes the consideration of installing low loss transformers, conductors and other equipment, where it is economic to do so.

[2] Voltage conversion projects **–** In many cases, by-passing and thus providing capacity relief for Distribution Stations by supplying some of the incremental loads from high voltage feeders (typically 27.6 kV) is considered as an alternative, with benefits from the reduced losses included in the evaluation. These projects are also considered as an alternative when Distribution Stations need to be replaced due to end of life considerations.

[3] Reducing load on heavily loaded feeders – Unloading heavily loaded feeders by transferring load to alternate feeders or new feeders can be effective in reducing losses and is utilized, where economic.

[4] Load growth/risk reduction projects - These include phase balancing, voltage improvement, power factor correction, and voltage upgrades.

[5] Installing larger conductors – When replacing conductors that reach their End-of-Life, larger size conductors than the ones required for meeting thermal requirements are installed when feasible. This reduces losses, particularly on heavily loaded feeders.

5.2 Specific Initiatives

The existing Hydro One distribution system was designed and built assuming specific load growth rates and loading patterns. However, in some cases these assumptions do not materialize as forecasted. As a result, some feeders end up loaded in a sub-optimal manner from a perspective of minimizing losses. This situation presents an opportunity to further minimize losses on the Hydro One distribution system. To uncover the extent of these opportunities Hydro One has contracted with Kinectrics to establish the most cost effective approaches for the Hydro One distribution system. The results of this analysis by Kinectrics are contained in Appendix A of this Exhibit. Hydro One has filed a report with the Ontario Energy board outlining it's planned Demand Management Program. This program includes a loss reduction component based on the findings of Kinectrics. The related Capacitor installation program is described in the Business Case Summary for the work presented in Exhibit D2, Schedule 2, Tab 3 **C4**.

KINECTRICS INC. REPORT ON DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

Appendix A

DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

Kinectrics Inc. Report No: K-011568-001-RA-0001-R00

July 20, 2005

Ray Piercy
Senior Engineer
Transmission and Distribution Technologies

Stephen L. Cress
Manager – Distribution Systems
Transmission and Distribution Technologies

PRIVATE INFORMATION

Kinectrics Inc., 800 Kipling Avenue
Toronto, Ontario, Canada M8Z 6C4

DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

Kinectrics Inc. Report No.: K-011568-001-RA-0001-R00

July 20, 2005

Ray Piercy

Prepared by: ________________________________

Ray Piercy
Senior Engineer
Distribution Systems

Peer Review by: ________________________________

Stephen L. Cress
Manager – Distribution Systems

Approved by: ________________________________

Dr. John Kuffel
Manager
Transmission and Distribution Technologies

Dated: July 29, 2005

DISCLAIMER

REVISIONS

Revision Number	Date	Comments	Approved

DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

Kinectrics Inc. Report No.: K-011568-001-RA-0001-R00

July 20, 2005

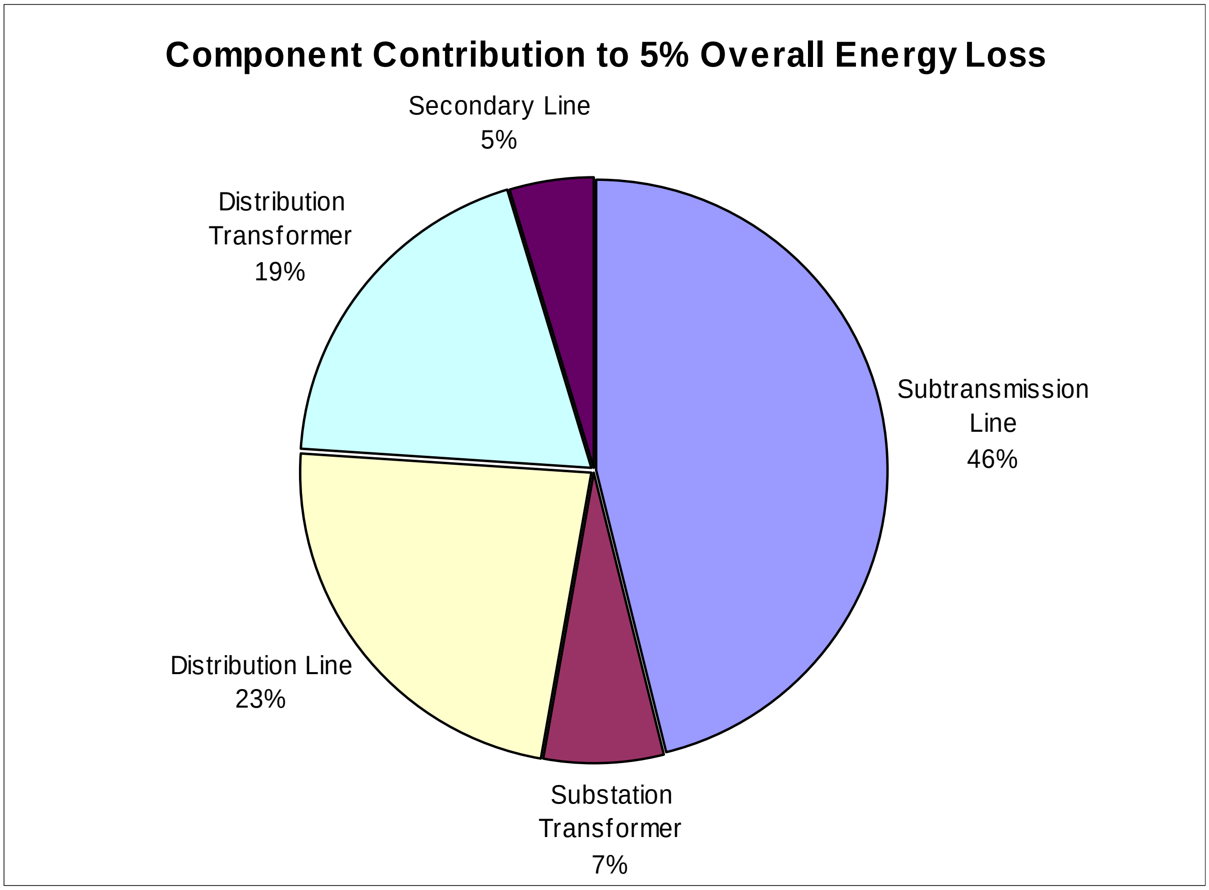
EXECUTIVE SUMMARY

As part of the support for the rate application to the OEB, Hydro One requested a study of the energy losses on its electric power distribution system. The project included an overall assessment of technical energy losses on various components of the distribution system, an allocation of losses to different rate classes resulting in distribution loss factors for each class, and development of a program to reduce energy losses.

High level system modeling using system component inventories and loading data from 2005 and 2004 has shown that the best estimate of the annual energy loss in Hydro One distribution systems is 5.05% of energy sales, with an outside range of 3.9 to 6.1% based on input parameter sensitivity modeling. The contribution of different system components to this total is shown in the pie chart on the following page.

The distribution system loss has been allocated to the major rate classes to produce several distribution loss factors (DLF). The comparison of these new DLFs with those that have been in use for the last three years is shown in the table on the following page. Computation of DLFs for more specific rate classes (R1, R2, UG etc.) and customer specific DLFs for subtransmission customers has been investigated, but further data gathering and discussion of implications is recommended before this is used in rate calculations.

The recommended loss management program for Hydro One is based on a combination of shunt capacitor installation and phase balancing. A program with an overall benefit to cost ratio of 5:1 has been designed based on a combination of $10.3 million in capital spending on shunt capacitors and $2.2 million in O&M costs on phase balancing over the next two years. A further study of the total ownership cost of transformers has been recommended, to develop an appropriately designed cost of loss equation to optimally size and load replaced transformers. This will also be a cost effective method of loss reduction but the loss reduction could only be achieved over many years. Investigation of opportunities for conductor replacement may also reveal specific sites where this method of loss reduction may be cost effective



Customer Type	DLF in Present Rates*	Total Estimated DLF*
Embedded LDC and Subtransmission Customers	3.4%	4.4%
Primary Customers	6.1%	6.8%
Secondary Customers	9.2%	9.6%

* Note: These DLFs include technical losses and non-technical losses on the distribution system and the supply facilities factor (0.6%) for losses on the transmission system.

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To: Carmine Marcello
Director of System Investment
Hydro One Networks Inc.
483 Bay St.
Toronto, ON
M5G 2P5

DISTRIBUTION SYSTEM ENERGY LOSSES AT HYDRO ONE

1. CONCLUSIONS AND RECOMMENDATIONS

1.1 OVERALL LOSS ESTIMATE

A high level computation using the latest system component inventories and loading data has shown that the best estimate of the annual energy technical loss in Hydro One distribution systems is 5.05% of energy sales, with an expected range of 3.9 to 6.1%.

The loss breakdown by power system component is shown in the following table.

Component	**Estimated Loss as a Percent of Total Energy Sold**
Subtransmission Lines	2.33
Power Transformers No Load	0.21
Power Transformers Load	0.12
Distribution Lines	1.18
Distribution Transformers No Load	0.78
Distribution Transformers Load	0.19
Secondary Lines	0.24
Total	5.05

1.2 DISTRIBUTION LOSS FACTORS

The Distribution Loss Factors (DLFs) calculated based on these technical losses are shown in the following table and compared to the previous DLF values used by Hydro One.

Customer Type	**DLF in Present Rates**	**Total Estimated DLF**
Embedded LDC and Subtransmission Customers	3.4%	4.4%
Primary Customers	6.1%	6.8%
Secondary Customers	9.2%	9.6%

The DLFs in the above table include the technical and non-technical losses on the distribution system and an allowance of 0.6% for loss in the transmission system.

1.3 TECHNICAL LOSS REDUCTION PROGRAM

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. These estimates are based on the characteristics of the Hydro One distribution system and the avoided costs for generation, transmission, distribution and environmental impacts. The present value of the benefits has been calculated over twenty years. The overall benefit to cost ratio of the program is 5:1.

Program Savings

Program	**Maximum Reduction in Annual Energy Loss GW-hr**	**Avoided Energy Demand and Environmental Costs PV $M**
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAr or more	53	52.9
Phase balancing - balance 750 circuits	15	11.4

Program Costs

($'000s)				
Distribution Network Loss Reduction	**2004/2005**	**2006**	**2007**	**Total**
PF Correction Capacitors		2,600	7,700	10,300
Phase balancing		700	1,500	2,200
Reconductoring		100	na	100
Transformer Size and Efficiency		150	na	150
Total				12,750

2. INTRODUCTION

As part of the support for the rate application to the OEB Hydro One has requested a study of the technical line losses on its electric power distribution system. The project included an overall assessment of technical energy losses, an allocation of loss to different types of customers resulting in distribution loss factors (DLF) for each type, and development of a program to reduce energy.

Energy losses on power systems can be divided into two broad categories, technical losses and non-technical losses. The majority of this report deals with technical losses, however a brief discussion of non-technical losses is provided in section 2.2.

2.1 DEFINITION OF TERMS

Distribution Loss Factor (DLF)
A factor used to increase the measured energy from a customer's meter to account for losses in the delivery of the energy. Strictly speaking it should be a value with no units such as 1.08 but it is often expressed as a percentage using just the decimal part, for example 1.08 is expressed as 8%. It includes technical losses, an adjustment for theft and other non-technical losses and the supply facilities factor.

Supply Facilities Factor
A value added to the DLF to account for loss in the transmission system. This has been previously estimated to be 0.6% by Hydro One.

Technical Losses
Power or energy used in the components of the system that delivers electricity to the customer's meter. This includes conductor losses that depend on resistance and current and transformer losses that include a conductor loss and a core loss. The core loss does not vary with loading.

Power losses are expressed in kW or as a % of the loss at peak load.
Energy losses are expressed in kW-h per year or as a % of the total energy sold in a year.

Non-technical Losses
Includes all unaccounted for energy other than technical losses. This can occur through theft, meter inaccuracies, billing errors etc.

Loss Allocation
When technical losses are not averaged over all customers on the system they are divided into parts and each part assigned (allocated) to a different customer or group of customers. The loss allocation can be either power or energy losses, but usually it is energy losses. It can be expressed in kW-h or as a % of energy sold to that customer or group of customers in a year. The loss allocation is often used as a basis for a DLF. The DLF for a specific customer group can be calculated by adjusting for the amount of energy sold to that group and adding a factor for non-technical losses and the supply facilities factor.

Loss Factor
A factor used to convert the power loss at peak load to the average power loss. It depends on the details of the load profile, i.e. how the load changes with time. It is often estimated based on an equation involving the load factor as follows:

$$\text{Loss Factor} = p \times \text{load factor} + (1-p) \times \text{load factor}^2$$

The constant "p" in this equation depends on the load profile. It is typically 0.3 for subtransmission systems, 0.2 for distribution lines, and 0.15 for distribution transformers and secondary circuits.

Load Factor
A factor used to convert peak power to average power. It is the ratio of the average power to the peak power.

2.2 NON-TECHNICAL LOSSESS

Non-technical losses occur as a result of the difference between the amount of electricity distributed to customers and the amount that is actually paid for. These losses occur because of the following:

- Theft, fraud, meter tampering/bypassing
- Faulty meters - resulting in the amount of electricity used being under-recorded.
- Incorrect records, billing errors

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales. (Ref 3).

Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold (Ref 1) and the upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors (Ref 2).

Any distribution loss factor calculated from technical loss allocation must be increased to cover all forms of non-technical loss. In the past Hydro One has used a figure of 10% of the technical losses to estimate non-technical losses. With technical losses at approximately 6% of energy sold this represents only 0.6% of energy sales as an estimate for non-technical losses. This is well below (<15%) of the published figures for utilities in North America and is less than that used in Australia or most of the United Kingdom. A more reasonable estimate for theft and other non-technical losses would by 1.2% of energy sales. This figure has been adopted in this report.

3. OVERALL TECHNICAL LOSS ESTIMATE

3.1 METHOD

There are two basic methods that can be used to calculate technical energy losses, a method based on subtraction of metered energy purchased and metered energy sold to customers and a method based on modeling losses in individual components of the system.

The method based on subtraction of energy sold from energy purchased is the traditional method outlined by the OEB. This method is not appropriate for Hydro One because of the extensive metering system that would be required and does not now exist. The existing meters do not total energy over the same time periods because they are manually read at fairly long intervals. More expensive metering would be required. Energy meters are also not installed at all intermediate levels of the system where they would be required to allocate losses to different types of customers.

The method of loss estimation based on modeling losses in individual components of the system has been used in this report in order to be able to allocate different amounts of loss to different types of customer within Hydro One. The following method was applied to each system component (subtransmission lines, power transformers, distribution lines, distribution transformers, secondary lines):

1. Identify different types of the component that would have different losses (e.g. different transformer ratings, line voltage levels, secondary line lengths etc.)
2. Assume a load profile for each component type (hours per year at each load level)
3. Calculate from the load profiles, values for load and loss factors for each component
4. Estimate the number of each type of component in the Hydro One system
5. Calculate the total loss at peak load and the annual energy loss.

The energy loss computation requires information on several basic factors: the inherent loss of the component, the profile of time varying load on the component, and the population of such components on the Hydro One system. The following sections describe the details of the loss computation for each separate type of component.

3.1.1 Subtransmission Lines

The number of subtransmission circuits at each voltage level and the total circuit length was available from spreadsheet “PSDB_Feeders_2005_07_14.xls” obtained in July 2005. There are 300 circuits at 44 kV, 221 circuits at 27.6 kV and 42 circuits at 13.8 kV. Circuits that are metered at the transformer station and/or owned by other utilities were not included. The 44 kV circuits were divided evenly into two different types, 44 kV in a developed rural area (surveyed lines and concession roads) and 44 kV in a sparse load rural area. The total length of subtransmission line was 15,800 km, obtained from Dx asset inventory numbers. A linear feeder topology was used for all types with four sub-stations per circuit in the developed rural areas and with two stations per circuit in all other types. An average value of conductor resistance was used based on the proportion of conductor sizes used in Hydro One. The circuit topology and the conductor sizes were based on an examination of Hydro One circuit maps.

The Hydro One load data spreadsheet (DNAMLoadingNov11.xls) provided the frequency distribution of total peak load on all sub-transmission circuits (78.7% of rating on average). The average peak loading was used in the calculation, adjusted to give the 2004 energy sold, obtained from "Dx Losses Customers Info.xls", but the resulting loss was multiplied by an adjustment factor to account for the actual distribution of peak loading obtained from the load data spreadsheet. The factor was calculated as the weighted average of the ratio of the per unit loadings squared.

Load loss at load levels other than the peak load was calculated by multiplying the load loss at peak load by the ratio of the square of the currents.

3.1.2 Power Transformers

The most recent load data for Hydro One substations was available in a data base "TLL Database_Apr_18_release.mdb", obtained in April 2005, as the sum of the load on all circuits of a substation. The total number of substation transformers was obtained from a text file, "Dx transformers .doc" provided by Hydro One in July 2005.

Typical load and no-load loss data for power transformers was available from a detailed study of 170 power transformers in Hydro One Networks. The differences in percentage loss between different voltage levels and MVA size was negligible so all transformers were assumed to be the average size.

The number of customers with power transformers was obtained from the "TLL Database_Apr_18_release.mdb", obtained in April 2005. Some of these customers are metered on the high voltage side of their transformers and the transformer loss should therefore not be included in the Hydro One loss estimate. The exact number of these customers is not known but examination of many circuits diagrams discovered that most LDC customers are metered on the high side and most other customers are not. Therefore all non-LDC customer transformers were included and no LDC customer transformers.

The energy sold through substation and customer power transformers was available from a spreadsheet "Dx Losses Customers Info.xls" provided in July 2005. The data was from 2004. This is the most recent data available. The total number of transformers, the total energy sold and the resulting peak load on the transformers was compared with data from previous calculations to ensure that it was reasonable.

The average peak loading was used in the calculation of transformer losses but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading obtained from the database. The factor was calculated as the weighted average of the ratio of the per unit loadings squared. The total loading was adjusted to give the correct annual energy sales through each type of power transformer.

Daily load profiles were obtained from data (based on load studies in the 1980s) for the different customer classes (residential, seasonal, farm, general <5 MW). This is the most recent load profile data available. The aggregate load profiles for the different types of customer are not expected to have changed significantly since this data was obtained. These daily load profiles were combined using the appropriate number of each type of customer for Hydro One into a total daily load profile. The Hydro One monthly load profile was combined with the total daily load profile to give a total number of hours at each load level in steps of 10% per unit. These hours were used to convert peak values into annual energy for both loss and energy delivered.

Load loss at load levels other than the rated load was calculated by multiplying the load loss at rated load by the ratio of the square of the currents.

3.1.3 Distribution Lines

Five different types of distribution line were modeled, based on voltage level (4.16, 8.3, 12.5, 25, and 27.6 kV). The number of each type was obtained from the spreadsheet "PSDB_Feeders_2005_07_14.xls" obtained in July 2005 and the frequency distribution of total load on each circuit was obtained from the data base "TLL Database_Apr_18_ release.mdb". A topology of a three phase main trunk with single phase laterals was used, with three main trunk sections and 25 lateral sections. The conductor sizes and lengths of each section were estimated based on examination of Hydro One maps. Loads were assumed to be evenly distributed. The total length of distribution line was 103,600 km, obtained from the Dx asset inventory numbers

The average peak loading for each circuit type was used in the calculation, adjusted to give the correct energy sold in 2004, but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading. The factor was calculated as the weighted average of the ratio of the per unit loadings squared. The same factor was used for all types.

The loss was also adjusted by factors to account for the distribution of imbalance between phases on the circuits (obtained from the April database) and for the assumed power factor of 0.92. The power factor assumption was based on a small sample of circuits for which measured values were obtained for other detailed projects in recent years.

Load loss at load levels other than the peak load was calculated by multiplying the load loss at peak load by the ratio of the square of the currents.

3.1.4 Distribution Transformers

Sixty different types of transformer were modeled, including twelve different kVA sizes in five high voltage ratings. The no load and load losses for each type of transformer was obtained from a Kinectrics data compilation which is based on manufacturer's data.

The total number of distribution transformers was 470,543, available from the Dx asset inventory numbers. The number of transformers at each voltage level was calculated using the proportion of circuit km at each voltage level (from the April database) and the distribution of transformer sizes was obtained from previous studies of Hydro One circuits in the Kingston area.

The average peak load on each transformer was assumed to be the same for all types since there was no data to support differences. The average peak load was calculated to give the total energy sold to retail customers in 2004. The average peak loading for each type was used in the calculation but the resulting load loss was multiplied by an adjustment factor to account for the actual distribution of peak loading. The factor calculated for distribution lines was used for distribution transformers because the frequency distribution specific to transformers was not available.

Load loss at load levels other than the rated load was calculated by multiplying the load loss at rated load by the ratio of the square of the currents.

3.1.5 Secondary Lines

Five types of secondary line were modeled: residential year round (urban and rural), residential seasonal, farm and general. Three phase farm and large customer general classes were assumed to be metered close to the transformers without the use of Hydro One secondary circuits.

All were assumed to be 120/240 Volt secondary except general which was assumed to be 600/347 Volts.

Most secondary lines were assumed to be directly from the transformer with no secondary bus as described in the Hydro One Line design standard and were assumed to use 3/0 Al triplex conductor. Urban customers were assumed to have eight customers per transformer and a secondary bus parallel to the road and then a perpendicular service drop.

The lengths of line were assumed to be 15m, 50m, 75m, 25m, and 10m respectively for the different types of customer. The maximum in the line design standard is 75m. Farms are usually shorter than residences because a primary line is run back from the road. General customers have shorter secondary lines because the meter is usually installed close to the transformer before the secondary is split to provide multiple main load locations.

The proportion of customers in each type was obtained from the “Dx Losses Customers Info.xls” spreadsheet.

3.2 RESULTS

The overall technical loss results are shown below in Table 1. The overall loss estimate is 5.05% of energy sold. This is the sum of the annual losses (1,976 GWh) divided by the total energy sold by Hydro One in a year (39,165 GWh). This total energy does not include the energy sold by Hydro One to non-embedded LDCs and non-embedded direct customers. These customers are supplied through dedicated subtransmission lines that are metered at the transformer station. All the losses in those lines are accounted for by the customer since they occur downstream of the revenue meter.

The loss percentage may appear to be high compared to urban utilities and low compared to most rural utilities. Hydro One's loss percentage is dependent on the composite rural/urban nature of their system and the fact that Hydro One serves many customers directly from their subtransmission system. The losses in Hydro One are higher than those in urban utilities because of the large rural area served by Hydro One. Rural areas have longer power lines with fewer customers per kilometer of line which increases the line losses. Distribution transformer losses also tend to be higher in rural utilities because of the minimum practical size of distribution transformer and the lack of load diversity when it only supplies a single customer.

The losses in Hydro One appear lower than most rural utilities because Hydro One provides 48% of its energy sales to customers at the subtransmission level, without use of distribution lines, distribution transformers and secondary conductors. This is a much larger percentage than most rural utilities because Hydro One serves local distribution companies. This means that 48% of the energy does not flow through the components of the system that produce half of the losses.

Another consequence of the high proportion of energy sold at the subtransmission level is that a larger proportion of Hydro One's losses occur at this level (46%) than would be typical of most utilities. This makes the portion of loss attributed to other components look smaller. For example, the 5% of the loss occurring on secondary lines is more typically 10% for other utilities.

The energy delivered through the sub-transmission lines (35,000 GWh) is less than the total sold (39,165 GWh) because some of the energy is sold through high voltage substations supplied directly from the 115 kV transmission system.

Table 1   Summary of Loss Estimation Results

	Peak Power (delivered by component) (MW)	Annual Energy (delivered by component) (GW-h)	Power Loss at Peak (MW)	Power Loss at Peak (% of total)	Annual Energy Loss (GW-hr)	Annual Energy Loss (% of total)	Annual Energy Loss as % of total energy sold
Subtransmission Line	8,600	35,000	200	34	913	46	2.33
Power Transformer No Load	3,270	20,500	9	2	82	4	0.21
Power Transformer Load	3,270	20,500	11	2	48	2	0.12
Distribution Line	4,530	18,750	233	40	461	23	1.18
Distribution Transformer No Load	4,290	16,900	35	6	304	15	0.78
Distribution Transformer Load	4,290	16,900	37	6	74	4	0.19
Secondary Line	4,290	16,800	62	11	93	5	0.24
Totals			587	100	1,976	100	5.05

The total annual energy delivered by the subtransmission lines is less than the total purchased from the transmission grid (39,165 GWh) because some of the energy purchased flows through high voltage substations supplied directly from 115 kV. Similarly the total energy delivered by distribution lines is less than the energy delivered by distribution transformers and secondary lines plus the primary customers because some of those distribution transformers are directly connected to 27.6 kV subtransmission lines in south west Ontario.

4. CALCULATION OF DISTRIBUTION LOSS FACTORS

The total loss percentage is calculated with reference to the total energy sales. However, when a DLF is applied, it is only applied to the portion of the total sales actually delivered to a particular customer group. In order to fully recover the costs for losses allocated to the group the DLF must be larger than the loss expressed as a percentage of total energy sales.

To calculate the DLF for the subtransmission customers (embedded LDC's, embedded directs and Transmission class customers) the first step is to calculate the fraction of the total energy sold that is sold to this group (19,089 / 39,165) which is 0.48 of the total. This fraction of the loss on the subtransmission lines and power transformers must be allocated to these customers (0.48 x (913+82+48)) which is 500 GWh. The DLF from technical losses alone is then 2.6% (500 / 19,089). Adding 1.2% for non-technical losses such as theft gives a final DLF of 3.8%. This can be compared with the previous DLF for this group which was 2.8%. Most of the difference is that the previous 2.8% DLF only included 0.28% for non-technical losses. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 4.4%.

To calculate the DLF for primary voltage customers a similar procedure is used. They purchase 8.3% of the energy sold through subtransmission and 16.2% of the energy sold through distribution lines. Their allocation of loss is therefore 161 GWh (0.083 x (913+82+48) + 0.162 x 461). And the DLF due to technical losses is 5.0% (161 / 3249). Adding 1.2% for non-technical loss such as theft gives a DLF of 6.2%. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 6.8%.

Secondary customers purchase 43% of the energy sold through subtransmission, 84% of the energy sold through distribution lines and 100% of the energy sold through distribution transformers and secondary lines. Their allocation of losses is therefore 1307 GWh (0.43 x (913+82+48) + 0.84x461 + 304 +74 + 93). The part of the DLF created by technical losses is 7.8% (1307 / 16,833). Adding 1.2% for non-technical losses such as theft gives a DLF of 9.0%. When the supply facilities factor of 0.6% is added to account for loss in the transmission system the total DLF is 9.6%.

The following table compares the previous DLF's used by Hydro One, with the new DLFs calculated in this study.

Table 2 Comparison of DLFs

Customer Type	DLF in Present Rates	Technical Losses part of DLF	Total Estimated DLF
Embedded LDC and Subtransmission Customers	3.4%	2.6%	4.4 %
Primary Customers	6.1%	5.0%	6.8%
Secondary Customers	9.2%	7.8%	9.6%

The DLFs in Table 2 include the 0.6% supply facilities loss factor.

5. SENSITIVITY STUDY

The assumed values for various parameters in the model that produced the global system loss estimate have been varied over their reasonable range to determine the probable error in the total estimate.

Table 3 Sensitivity Study Results

Parameter	**Value used**	**Maximum**	**Minimum**	**Range in Total Loss (as a % of estimated loss)**
Conductor size in main sections	556 AL and 336 AL	556 AL	336 AL	±12%
Factor adjusting for peak loading differences from average [note1]	1.8	+10%	-10%	±8%
Load level	normal	+10%	-10%	±6%
Load profile (load factor)	0.5	0.7	0.35	±4.5%
km of distribution line	103,000 km	+10%	-10%	±4%
Distribution line current imbalance	24% average	+10%	-10%	±4%
km of subtransmission line	15,800 km	+10%	-10%	±2.5%
Transformer no load loss	power 0.14% dist. 0.27%	+10%	-10%	±2%
Number of distribution transformers	470,000	+10%	-10%	±1.5%
Split of circuits between developed and rural 44 kV	50/50	70 / 30	50 / 50	±1.3%
Split of line lengths between developed and rural 44 kV	50/50	35 / 65	50 / 50	±1.2%
Transformer load loss	power 0.4% dist 1.4%	+10%	-10%	±1%
Number of power transformers	1425	+10%	-10%	±1%
Topology of subtransmission lines	both	Linear	branched	±0.7%
Length of secondary line	47,800 km	+10%	-10%	±0.7%
Resistance of secondary line	0.35ohms/km	+10%	-10%	±0.6%
Number of secondary circuits	925,000	+10%	-10%	±0.6%

Note 1 The factor adjusting for peak loading differences from the average converts the loss calculated from the average loading on the circuits or transformers into the actual loss created by the distribution of loading.

The cumulative effect of all the parameter sensitivities, some positive and some negative is expected to be ±22% of the estimated loss in GW-h or ±1.11% of the energy sold. This is a practical estimate of the probable range, not a “worst case”.

6. TECHNICAL LOSS MANAGEMENT PROGRAMS

Technical losses on distribution systems are primarily due to I^2R losses in conductors and magnetic losses in transformers. Losses are inherent to the distribution of electricity and cannot be eliminated but may be minimized. In order to properly manage the inevitable losses it is necessary to understand the relative impact of different sources of losses. The largest source of losses is not always the easiest to reduce. Some sources can be reduced more cost effectively than others.

Canadian Electricity Association Technologies research has developed loss estimates for “typical” urban and rural distribution systems as shown in Table 4 below. Hydro One has primarily rural distribution with some pockets of urban development. Independent assessments of Hydro One’s distribution system losses indicate that technical losses are in the order of 4.4% of the energy delivered to the distribution system. This represents annual energy losses of approximately 1,700 GW-hr. Losses occur on 3-wire subtransmission lines, 4-wire distribution lines, station transformers, line transformers and secondaries to customers. Transformer losses include no-load losses that are independent of transformer loading and load losses that vary with loading. The breakdown of these losses from the various causes is shown in Table 4.

Table 4 Typical Loss Values

	Estimated Loss as a Percent of Energy Sold		
Component	**CEATI Typical Urban**	**CEATI Typical Rural**	**Hydro One***
Subtransmission Lines	0.1	0.7	2.33
Power Transformers	0.1	0.7	0.33
Distribution Lines	0.9	2.5	1.18
Distribution Transformers No Load	1.2	1.7	0.78
Distribution Transformers Load	0.8	0.8	0.19
Secondary Lines	0.5	0.9	0.24
Total	**3.6**	**7.3**	**5.05**

* Note: This table does not include the non-technical losses or the supply facilities factor that is included in Hydro One’s total Distribution Loss Factors.

Management of system losses is an on-going consideration in the planning, design, operation, purchase, upgrading and replacement of Networks’ distribution facilities and equipment. Nonetheless, Networks believes that there is an opportunity to achieve incremental economic reductions in distribution system delivery losses through targeted investment programs. Modest reductions in losses can yield considerable benefit in terms of avoided cost of energy and demand.

Studies of Hydro One distribution losses have indicated that there are several methods that can be practically and economically applied to reduce distribution losses. These include:

- Power factor correction using shunt capacitors
- Balancing of load on phases
- Reconductoring lines which presently have under-sized conductors
- Installing properly sized high-efficiency transformers

Each method is limited in the amount of energy that can be saved as well as a penetration limit on the number of Hydro One sites that would be amenable to the particular loss reduction method. Furthermore each method has an associated cost of implementation. Table 5 shows the results of demand and energy savings that were achievable in applying loss reduction methods to particular Hydro One feeders. The Profitability Index is provided as an indicator of how the reduction in the cost of losses relates to the investment required to achieve these savings. The Profitability Index is calculated as the net present value of the savings in loss costs over twenty years divided by the cost of the loss reduction method.

Table 5 Effects of Loss Minimization Techniques Applied to Example Feeders

Loss Reduction Technique	Reduction of Peak Losses (% Peak Feeder Losses)	Reduction of Loss Costs (% Feeder Loss Costs)	Profitability Index
Capacitor application	3.1%	3.2%	4.2
Phase Balancing	2%	1.6%	5.4
Reconductoring	30%	29%	1.4
Re-sizing Distribution Transformers	2.3%	4.1%	0.1

6.1 DESCRIPTION OF THE PROGRAM

The Distribution Network Loss Reduction Program will involve identifying and implementing projects where incremental investments will result in an overall economic benefit to customers by reducing system delivery losses.

The three major areas offering the best economic opportunities are described below and information on the project costs and financial benefits is provided:

- ***Power Factor Correction using Shunt Capacitors***

  Feeder power factors in the Hydro One distribution network are typically in the range of 0.85 to 0.95, depending on time of year, mix of customers, and customer usage patterns. Power factor correction can be achieved through application of shunt capacitor banks. Capacitors reduce feeder losses by providing reactive power compensation near the load, thereby reducing the current flow in the line. The challenge in capacitor application involves the determination of the location, size, number and type of capacitors to be placed in the system. Fixed and/or switched capacitors can be used in the system. Fixed shunt capacitors provide constant reactive power compensation and are suitable for loads having approximately constant reactive power requirements. Switched shunt capacitors are used in cases of load variability since they allow more flexibility in controlling the losses and voltage drop. Hydro One purchases rack mounted capacitors with pre-installed oil switches. Targeting feeders with the known poorest power factors will generate the highest contributions to loss reduction DSM.

A preliminary analysis has indicated a potential for saving and forms the basis of the capacitor installation plan. It indicates that shunt capacitor banks could be applied to 660 Hydro One feeders (70 feeders with 600 kVAR banks, 150 with 450kVAR units, and 440 feeders with 300KVAR banks). When fully implemented these capacitors would result in annual energy savings of approximately 53 GW-hr, about a 3.0% reduction in distribution system energy losses. This translates to a 20-year Present Value of savings in the order of $53M. The capital and labor cost for these installation in a two year program, plus analysis to determine optimal locations would be $10.3M. These costs and benefits are summarized in Tables 6 and 7 below.

Additional loss reduction could be achieved with the installation of switched capacitor banks which would match the connected kVAR to the variations in the load. Since this loss reduction method would require control schemes to monitor voltage levels, time of day and / or status of switching equipment, the costs would increase substantially, and will require further investigation in future.

- ***Feeder Phase Balancing/System Configuration***

The distribution network consists of approximately 400 “sub-transmission feeders” and 2700 “distribution” feeders. A considerable part of the Hydro One distribution system consists of single-phase residential loads, making the power flow in three-phase main feeders difficult to balance. The total I^2R loss in the three phases of an unbalanced system is higher than that of a balanced system, and therefore, a concerted effort to balance phases, can result in loss reduction. Phase imbalance is often expressed as the maximum phase current minus the average of the phase currents divided by the average of the phase currents. At the present time phase imbalances at the distribution stations on the worst third of the Hydro One feeders are in a range of 30% to 100 % indicating considerable room for improvement.

The phase balancing program will target the worst 750 of Hydro Ones’ distribution feeders in a 2-year period. It is estimated that at full implementation, balancing of these feeders will result in a 15GW-hr annual energy saving. Since unbalance will recur with the passage of time, the benefits from this phase balance were estimated assuming a decline in energy savings over a 20 year period. With this assumption, the 20 year present value of avoided costs is about $11M. The cost to implement the phase balancing over a two year period would be $2.2M.

- ***Re-conductoring***

The sizing of distribution conductors and cables is normally determined by considering the thermal capability of the conductors and cables, and by the amount of voltage drop from source to the receiving-end. Hydro One's long rural feeders are generally voltage-drop limited as opposed to ampacity limited. Another consideration, however, is cost of losses related to the conductor size selected. The larger the conductor size, the lower are the losses. Larger conductors require more capital expenditures and a balance must be found when sizing the conductors. The conductor size is typically optimized, through the planning process, when a feeder is initially installed. However, as the system evolves and conditions change from original plans occurrences of sub-optimally sized conductors will materialize. Reconductoring of sections of a feeder that are heavily loaded can provide loss improvements.

Though not often highly profitable, reconductoring can be very effective in reducing losses on circuits that are particularly overloaded. As a portion of the distribution loss reduction program a study will be conducted to identify the Hydro One feeders that are prime candidates for reconductoring with profitability greater than one.

- ***Transformer Sizing and Efficiency***

The series and shunt resistance and reactance of distribution transformers result in significant losses on distribution systems. The consumption of reactive power by transformer reactance introduces higher reactive current flow in the primary circuits, which contributes to the system losses. Distribution system losses can be reduced by properly sizing the distribution transformers.

Transformer no-load losses are constant and depend on the size of the transformer installed and the loss formula to which it was purchased. Decreasing the transformer rating will decrease the no-load losses. On the Hydro One system it is notable that on many feeders, the actual peak load on the feeder is only 20 to 40 % of connected kVA. This implies that the connected kVA is unnecessarily high and a reduction in transformer sizes would not overload the smaller transformers. Consideration would have to be given to the cost of inventory for stocking smaller transformer sizes.

The low profitability index in Table 5 indicates that the cost of replacing existing transformers is typically beyond the benefits achieved. This illustrates that distribution transformers must be sized appropriately on initial installation in order to achieve minimal transformer losses.

Therefore, a portion of the distribution losses program will include a review of transformer sizing practices including the cost-of-losses formula, loss-of-life, load growth and inventory considerations. The intent is to minimize future losses by ensuring correct sizing and the purchase of transformers with the highest efficiency that can be justified by a total life-time cost consideration.

Benefits

Lowering distribution system delivery losses will reduce overall system demand and provide additional network capacity for growth. Since system delivery losses are currently passed onto all customers, improvements in this area will benefit all customers.

The expected benefits of the proposed distribution loss reduction program are summarized in the table below. These estimates are based on the characteristics of the Hydro One distribution system and are present valued over a twenty year period.

Table 6 Economic Benefits

Program	Maximum Reduction in Annual Energy Loss GW-hr	Avoided Energy Demand and Environmental Costs PV $M*
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAr or more	53	52.9
Phase balancing - balance 750 circuits	15	11.4

* Note: Present valued over a twenty year period

Table 7 Program Budget

($'000s)				
Distribution Network Loss Reduction	**2004/2005**	**2006**	**2007**	**Total**
PF Correction Capacitors		2,600	7,700	10,300
Phase balancing		700	1,500	2,200
Reconductoring		100	na	100
Transformer Size and Efficiency		150	na	150
Total				12,750

7. REFERENCES

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2. “Draft Decision: Approval of network Average Distribution Loss Factors for 2002/03”, Essential Services Commission, Victoria Australia, April 2002

3. Carolyn Hough, “Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering”, Sacramento California, 1998

4. Piercy, Ray; “Evaluating The Energy Efficiency of Distribution Systems”, CEATI Report T044700-5004, June 2005

APPENDIX 1 LOSS MANAGEMENT PROGRAM BACKGROUND, ASSUMPTIONS AND COMPUTATIONS

A1. Expected Technical Losses at Hydro One

Hydro One is a distribution utility with a mixed service area consisting of both rural and small urban areas. A recent study conducted by utilities in North East North America concluded that the technical losses of typical urban utilities range from 2% to 5% of energy sold and for typical rural utilities technical losses range from 4% to 10% of energy sold (Ref 4). It also concluded that the achievable level of energy efficiency is not the same for all utilities but varies depending on the details of the service territory and the past design practices. Present estimates of the technical losses at Hydro One have been in the range of 3.9% to 6.1% of energy sold (section 3). These estimates are for technical losses and do not include non-technical losses, such as theft.

A2. Available Loss Reduction Technologies and Approaches

The techniques that are most applicable to a specific utility system depend on which types of losses are the most significant on that specific system. There are no techniques that will be best in all circumstances. The amount of loss reduction that should optimally be implemented depends on the societal expectations, economic constraints, and competing values such as improved asset utilization. Improving asset utilization reduces overall capital costs but it increases the loading on equipment which also tends to increase losses.

There are two main sources of losses, conductors and transformers. Transformer losses can be reduced by design or loading changes. Design changes can be achieved by using lower loss steel in the transformer core, or by using windings with lower resistance, either by using copper instead of aluminum or by using larger wires or both. Since transformer losses depend on the design they can only be reduced by replacing a transformer with high losses with one with lower losses. Since transformers are expensive this is only feasible if done slowly as transformers are replaced for other reasons, such as age or under capacity.

The following methods can be used to lower conductor losses:

1. Using copper instead of aluminum
2. Using larger conductors
3. Using more transformer stations (shorter low voltage lines)
4. Using three phase lines instead of single phase
5. Installing capacitor banks
6. Balancing the load between conductors on the same line
7. Reducing peak loads by active or passive load control
8. Installing distributed generation

Some of these are methods that utilize capital costs and are basically unable to be retrofit on existing systems (3), some utilize capital costs but can be retrofit (1,2,4,5,7,8) and some utilize operations costs (6).

Choice of which method to implement first depends on both the technical efficiency (how much energy can be saved) and the economic efficiency (will savings be larger than costs). Previous studies have shown that the most cost effective methods are capacitor installation and phase balancing.

A3. Application of Loss Reduction to Hydro One

A3.1 Identification of Most Suitable Techniques

The most suitable techniques are efficient in both technical and economic terms.

The **installation of capacitors** reduces losses by correcting the power factor of the loads and thus reducing the current required to supply the same power and energy. The current flow in distribution feeders can be decomposed into active and reactive components. Applying a shunt capacitor, at the load end of the feeder, injects the capacitive current that results in reduction of the net reactive current. This result in a reduction of the overall line current and the effective apparent power at the load seen from the feeder. Therefore, as the current of the feeder is decreased, the conductor losses will be reduced. Moreover, the voltage at the load end is boosted which may allow better service to the customers. The amount of loss reduction achievable depends on the initial power factor. Ideally the best evaluation technique would be to measure the power factor on all circuits and calculate the current reduction that can be achieved on each circuit. However, at Hydro One the power factor is not measured on all circuits. A previous detailed study on eight Hydro One circuits found power factor varies from 1 to 0.92 with an average of 0.94.

Another suitable technique for loss reduction in Hydro One is **balancing the load** between conductors on the same circuit. Since many of the loads are on single phase lines it is never possible to get a complete balance. However, the latest data shows that the average imbalance on Hydro One distribution circuits is 26%. This means that the highest or lowest conductor current is 26% different than the average current. The balance of current between the phases is not a static quantity. It varies from one year to the next as loads grow, are added or removed from the system. Phase balancing is therefore a maintenance activity that needs to be done on a regular basis. The cost implementing this loss reduction technique is therefore a maintenance cost rather than a capital cost. An analysis of this loss reduction method is included in this report so that this method can be compared to the installation of capacitors and a suitable balance can be struck between implementing the two techniques.

A3.2 Estimation of Potential Energy and Peak Power Savings

The total potential for energy savings due to **capacitor banks** has been estimated from typical circuits. If an average power factor of 0.94 (ref cress) is assumed to be typical of the existing circuits then the most recent load data indicates that capacitor banks of at least 150 kVAr could be installed on 1560 of the 2700 circuits, assuming a minimum load of half the peak. With the assumed 0.94 power factor, this is estimated to reduce distribution line losses by 85 GW-h per year.

The kW savings in different loading periods has been estimated as follows based on modeling of typical circuits at each voltage level. The minimum single capacitor bank has been assumed to be 150 kVAr

	Winter			**Summer**			**Shoulder**	
	On peak	**Mid Peak**	**Off Peak**	**On Peak**	**Mid Peak**	**Off Peak**	**Mid Peak**	**Off Peak**
Hours	**602**	**688**	**1614**	**522**	**783**	**1623**	**1305**	**1623**
150kVAr	4.93	2.89	1.44	4.42	2.63	1.36	3.14	1.27
300kvAr	10.41	6.10	3.05	9.33	5.56	2.87	6.64	2.69
450kVAr	26.54	15.56	7.78	23.80	14.19	7.32	16.93	6.86
600kVAr	63.28	37.10	18.55	56.74	33.82	17.46	40.37	16.37

The potential energy and peak power savings from **phase balancing** has also been estimated based on analysis of typical circuits at each voltage level. It was assumed that after balancing the circuit would still be 10% unbalanced since this is an achievable minimum.

# Circuits Balanced	**Energy Savings per circuit MW-h**	**Peak Power Savings per circuit KW**
25	104	48
47	89	38
67	81	36
99	69	30
148	57	24
251	42	18
351	34	15
451	30	13
551	26	11
651	23	10
751	21	9

The decreasing energy savings per circuit is caused by the circuits with the largest imbalance being selected first. The first 25 circuits have 100% imbalance. By the last few rows of the table the 100 circuits between each row are moving from 30% unbalance to 10% unbalance.

Peak kW Saved in Different Time Periods

	Winter			Summer			Shoulder	
# Circuits Balanced	**On peak**	**Mid Peak**	**Off Peak**	**On Peak**	**Mid Peak**	**Off Peak**	**Mid Peak**	**Off Peak**
25	26.9	16.3	8.2	25.0	14.9	7.7	17.8	7.2
47	21.3	12.9	6.5	19.8	11.8	6.1	14.1	5.7
67	20.2	12.2	6.1	18.7	11.2	5.8	13.3	5.4
99	16.8	10.2	5.1	15.6	9.3	4.8	11.1	4.5
148	13.4	8.2	4.1	12.5	7.4	3.8	8.9	3.6
251	10.1	6.1	3.1	9.4	5.6	2.9	6.7	2.7
351	8.4	5.1	2.6	7.8	4.7	2.4	5.6	2.3
451	7.3	4.4	2.2	6.8	4.0	2.1	4.8	2.0
551	6.2	3.7	1.9	5.7	3.4	1.8	4.1	1.7
651	5.6	3.4	1.7	5.2	3.1	1.6	3.7	1.5
751	5.0	3.1	1.5	4.7	2.8	1.4	3.3	1.4

A3.3 Extent of Application of Loss Reduction Methods and Expected Achievable Savings

To estimate the savings that could be easily achieved by installation of **capacitor banks** it can be assumed that heavily loaded circuits will have a power factor of a maximum of 0.96. This is a conservative figure based on the known power factors. Assuming a minimum installation of 150 kVAr and a minimum load of half of the peak load, any circuit with a peak load of more than 1000 kW would have enough reactive power to install a capacitor bank. Circuits with more than 2200 kW load could have 300kVAR of capacitors installed, circuits with more than 3000 kW could have 450 kVAr of capacitors, and circuits with more than 4500 kW peak load could have 600kVAr of capacitors installed. The most recent circuit load data indicates there are 70 circuits that could have 600kVArs, 150 that could have 450 kVArs, 440 with 300kVArs and 900 that could have 150kVAr banks. This is a total of 1560 circuits with at least 150kVars. With the 0.96 pf assumption, the estimated energy savings in distribution line losses are 71 GW-h per year. Limiting the number of circuits to those which require the largest banks will increase the profitability index. If capacitors are applied to the 600 worst circuits, then 70 circuits with 600kVAr, 150 circuits with 450 kVAr, and 380 circuits with 300 kVAr could be installed. The estimated savings would be 50 GW-h per year. More capacitors could be installed if the power factor and minimum load of heavily loaded circuits was measured.

To estimate the savings that could actually be achieved by **load balancing** the diminishing returns evident in the table above have been taken into account. A reasonable level would be determined by the economic analysis. The savings from balancing last only a few years and gradually decrease in each year as the balance becomes poor again. A 20 year linear decrease is a reasonable assumption. In this case a 2 year program to balance the worst 750 circuits is proposed. This would save 15 GW-h per year at initial full implementation.

A3.4 Economic Analysis

The savings from the loss mitigation techniques were computed using the Avoided Cost methodology in the Navigant "Avoided Cost Analysis for the Evaluation of CDM Measures" report dated June 14, 2005.

Savings were computed both including and excluding environmental impacts using Table 23 and 21 of the Navigant Report respectively. Savings were further expressed as Present value over twenty years by applying a discount factor of 9.3% and an escalation factor of 2.5% to the tabulated values.

Distribution demand was evaluated at $6.5/kW however this value is expected to be high since it was computed by the Navigant localized method. Savings were computed neglecting the Distribution Demand factor and are provided in the Table below.

Savings for the mitigation techniques were computed over a 20 year period.

Capacitors were assumed to be installed 25% in 2006 and 75% in 2007. In the year of installation only half the energy savings of the banks installed in that year were received. In 2008 all the savings from all units was considered and these savings continued on to 2026.

Installed capacitor costs were considered to be as follows:

150kVAR	$14,500
300kVAR	$15,300
450kVAR	$16,000
600kVAR	$16,800
900kVAR	$19,500

250 circuits were considered to be **balanced** in 2006 and 500 additional in 2007. The per circuit cost of balancing was considered to be $3000 including one day's time for a bucket truck, crew and a technologist. Only half of the savings was considered in the year of installation. A factor was applied to reduce the energy savings in subsequent years to account for the gradual loss of the impact of balancing.

Avoided Energy and Demand Costs including Environmental Costs

Program	Reduction in Annual Energy Loss GW-hr	Avoided Energy Costs PV $M	Avoided Energy and Generation Demand Costs PV $M	Avoided Energy, Generation and Transmission Demand Costs PV $M	Avoided Energy, Generation , Transmission and Distribution Demand Costs PV $M
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAR or more	53	45.7	51.4	52.0	52.9
Phase balancing - balance 750 circuits	15	9.9	11.1	11.3	11.4

Note: Present value calculated over a twenty year period

Avoided Energy and Demand Costs without Environmental Costs

Program	Reduction in Annual Energy Loss GW-hr	Avoided Energy Costs PV $M	Avoided Energy and Generation Demand Costs PV $M	Avoided Energy, Generation and Transmission Demand Costs PV $M	Avoided Energy, Generation , Transmission and Distribution Demand Costs PV $M
PF Correction Capacitors - install cap banks on 660 feeders requiring 300kVAR or more	53	40.2	45.8	46.5	47.3
Phase balancing - balance 750 circuits	15	8.6	9.9	10.0	10.2

Note: Present value calculated over a twenty year period

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