SUSTAINING CAPITAL

1.0 INTRODUCTION

Distribution Sustaining Capital represents investments required to ensure that existing distribution system facilities function as originally designed. Hydro One Distribution manages its distribution sustaining capital program by dividing the program into three program categories, namely: stations, lines and meters

Stations, lines and meter program categories include investments in equipment and related components required to deliver electricity through the distribution system, as well as investments that facilitate the efficient use of joint-use of assets. Investments covered under the Sustaining Capital program are proposed for the purpose of maintaining the long term and short term functionality of assets, to ensure public and employee safety, comply with regulations and contractual requirements and to provide a level of reliability that is aligned with corporate objectives.

Hydro One Distribution's Sustaining Capital programs and proposed spending levels for 2008 are described below.

2.0 DISCUSSION

Distribution stations, lines and meter assets, and their components, are subject to deterioration that will eventually impede their ability to function as originally designed. Asset deterioration depends on factors such as geographic environment/location, utilization, age, weather and maintenance practices. As assets deteriorate, equipment performance reliability usually suffers, resulting in increased environmental risks, an increase in potential safety hazards to the public and employees, and decreased system

reliability. Ultimately, assets deteriorate to the point that they are no longer able to perform their function(s) in a cost-effective manner, at which point replacement becomes necessary rather than continue to repair or maintain.

Sustaining Capital programs fund both planned work and demand (unplanned) work. Planned work is required to preserve functionality of the existing distribution system by replacing deteriorated components with new components that are designed to perform an equivalent function. The identification of specific facilities for possible replacement is based on data collected during the Asset Condition Assessment (ACA) process described in Exhibit D1, Tab 2, Schedule 1. The condition of assets is one consideration in determining replacement. Other factors include historic performance, asset criticality, availability of spare equipment, load growth, and local customer impacts as well as the business drivers that form part of the work program prioritization process described in Exhibit A, Tab 14, Schedule 5. The prioritization process allows all distribution programs to be ranked and compared to one another so that investments can be directed to where they provide the maximum business value.

Demand capital work involves asset replacement that is required during service interruptions and in response to contractual and other commitments with road authorities and joint use partners, i.e., cable and telecommunication companies. The varying nature of this work requires Hydro One Distribution to forecast costs based on historical averages with adjustments made to reflect recent changes in expenditure patterns or work requirements.

Demand work requires an immediate or timely response to customer needs and is initiated by interruptions to service, line and station inspection findings, and by request from customer and property owners. Hydro One Distribution maintains infrastructure, equipment and resources to respond to these issues within the time lines specified by the

Distribution System Code. Planned work on the other hand, does not generally pose the same degree of urgency and is scheduled over time, based on knowledge of the condition of the assets.

The Sustaining Capital spending for 2008 and prior years is provided in Table 1 below.

Table 1
Sustaining Capital
($ Millions)

Description	Historic Cost			Bridge	Test
	2004	2005	2006	2007	2008
Stations	11.0	9.1	8.5	7.7	10.3
Lines	92.7	106.8	162.1	138.8	139.5
Meters	1.2	1.4	15.7	77.1	167.3
Total	**104.9**	**117.3**	**186.3**	**223.6**	**317.1**

The increase in spending for 2008 relative to historic expenditures is attributed to the following reasons:

- Implementation of smart meters, in accordance with government direction.
- Planned pole replacement during 2008 is greater than historic replacements based on ACA finding.
- An increase to the 2008 planned line refurbishment and component replacement levels to address end of life assets, and reliability and safety risks.
- Material and equipment increases in the order of 20% to 40%.
- An updated projection for storm response costs to reflect historical spending on this activity which is critical to providing customers with reliable service.

Additional details concerning these increases and year over year variations in spending are provided below.

2.1 Stations

Hydro One Distribution has 1,006 distributing and regulating station facilities, which are used for the delivery of power, voltage transformation and switching. Station facilities contain many of the following components: power transformers, instrument devices, reclosers, fuses, disconnect switches, bus, insulators, power cables, support structures, cable terminators, surge arrestors, station service supplies, grounding systems, fences, and buildings.

Hydro One Distribution's service to customers is also performed with a fleet of 28 mobile substations used primarily for emergency response to power disruption at stations. The mobile substations are also used during planned maintenance programs and capital refurbishment at distributing stations to reduce power interruptions. Investments for mobile substation are included in the Sustaining Capital program to ensure these mobile assets are available for the above purposes.

Stations Sustaining Capital funding covers capital investments required to replace or upgrade assets located within distributing and regulating stations, and mobile substations. The work is divided among three programs. Funding for 2008, along with the spending levels for the bridge and historic years are provided in Table 2 below.

Table 2
Stations Sustaining Capital
($ Millions)

Description	Historic Cost			Bridge	Test
	2004	2005	2006	2007	2008
Strategic Spare Transformers	4.8	1.7	2.8	0.6	3.5
Mobile Substation Refurbishment	1.1	0.4	1.0	0.3	1.5
Station Projects & Demand	5.1	7.0	4.7	6.8	5.3
Total	**11.0**	**9.1**	**8.5**	**7.7**	**10.3**

2.1.1 Management of Transformer Assets

Power transformers are devices used to reduce the voltage of the electricity being distributed, and to provide voltage control. Distribution power transformers convert a high level voltage (typically 115kV, 44kV, or 27.6kV) to a lower distribution voltage (typically 27.6, 25, 13.8, 12.47, 8.32 and 4.16 kV).

The management of transformer assets is a key component of the Stations Capital Sustaining program. The reliability of supply provided by power transformers is managed through proactive maintenance activities and a coordinated use of strategic spare transformers and mobile substations. These programs are interdependent and have proven to be a cost-effective approach for managing transformers for a largely rural utility such as Hydro One Distribution. This approach reduces capital expenditures for distribution facilities as discussed below while still providing reliable delivery of electricity to customers.

Hydro One Distribution's system is largely a radial system characterized by little or no load transfer capability, and by design the majority of distributing stations are equipped with only one power transformer. The consequence of this system design is that a

transformer failure at a distributing station results in a service interruption to all customers supplied from that station. Since service to customers cannot be restored until the function of the distributing station is restored, in many instances mobile substations are dispatched to the affected station to provide service restoration. The mobile substation remains in place until such time as a spare transformer can be brought in to replace the failed unit. The extent to which spare transformers are available will influence the reliance on mobile stations for extended periods. Alternatives to this management process include having a spare a transformer at every distributing station or building added supply lines to provide a redundant supply. These alternatives have been assessed to be cost prohibitive on a system wide basis.

Mobile substations also facilitate maintenance at distributing stations by carrying the station load while the station is isolated for planned maintenance work. The extent to which mobile substations are in-service for an extended period of time, due to unavailability of spare transformers, will limit the ability to complete the required planned maintenance and capital work at distributing stations.

Details of the programs used to manage strategic spare transformers and mobile substations are provided below.

2.1.1.1 Strategic Spare Transformers

Hydro One Distribution has 1,337 station transformers and 140 regulators in service. Hydro One's distribution stations have experience an average of 32 major station failures a year over the last 4 years. In a number of instances, station failures require removing the transformer off site and subsequent replacement from the strategic spare transformer inventory. The strategic spare inventory is maintained by purchasing new transformers if required and by refurbishing existing, unserviceable units, i.e. transformers that failed or

were required to be removed from service based on poor condition as determined through the ACA process.

The majority of distribution transformers that fail, or that are found to be unserviceable based on ACA results, can be refurbished economically. Repair costs can vary significantly, from $15,000 to $150,000 per transformer, depending on the nature of the failure and whether the damage results from external or internal faults. Before a transformer is refurbished, Hydro One Distribution first determines whether the transformer is needed as a spare, and estimates the refurbishment costs by dismantling the transformer and assessing the extent of damage. If refurbishing the transformer versus buying a new transformer is economically justified and is technically acceptable, the existing transformer is refurbished and added to the pool of strategic spare transformers.

Due to the importance of these system elements to customer reliability, Hydro One Distribution maintains a spares inventory of transformers and regulators that is based on the number and type of transformers and regulators in-service, reliability of equipment in use and the availability mobile substations. Historically, each year two to six station transformers cannot be returned to the spares inventory. In these cases, the complement of spare transformers is reduced unless replacement transformers are purchased, or transformers become available through system reinforcement projects, i.e. transformer replaced in response to an increase in customer load is freed-up for another use. This program funds the purchase of transformers to maintain a spares compliment that meets system needs and ensures reliability.

Funding of this program enhances customer reliability by reducing the reliance placed on mobile substations for extended periods, making them available to respond to emergencies and to assist in carrying out the planned maintenance on distributing stations, thereby ensuring equipment performance.

The 2008 spending requirement for this program is $3.5 million. Historically expenditures have fluctuated from year to year based on the number of failed transformers that are beyond repair and replaced by transformers from the spares pool. Those transformers removed from the spares pool that become permanent field installations need to be replaced in the spares inventory to maintain adequate spares coverage. In addition, system failures are monitored and if there is an appreciable increase in the failure rate of a specific class of transformer, there may be a need to increase the number of spares within the subject group to manage reliability to acceptable levels.

The 2008 spending involves the purchase of 3 new spare transformers and 1 regulator to increase the compliment of spares to the required levels.

Funding reductions in this program would result in an increased utilization of mobile substations at failed transformer locations thereby negatively impacting planned maintenance and jeopardizing reliability at a number of distribution stations.

For additional details refer to the Investment Justification Document (IJD) in Exhibit D2, Tab 2, Schedule 3.

2.1.1.2 Mobile Substation Refurbishment

A mobile substation is essentially a distribution station mounted on a trailer suitable for traveling on public roads. These mobile units consist of a transformer, high voltage and low voltage switches, high voltage and low voltage fuses, and connecting bus. There are 28 of these units strategically located across the Province. The primary purpose of mobile substations is to provide emergency backup to distributing stations and restore service to customers following the failure of a station, but they also facilitate planned maintenance

programs at distributing station assets by mitigating power disruption to customers. Given Hydro One Distribution's largely radial distribution system with single transformer distributing stations, the utilization of mobile substations provides a cost effective alternative to constructing redundant transformation at stations.

As mobile substations age, the undercarriage, wheels, axles, and suspension require replacement when routine maintenance cannot restore the integrity of the components. Funding of this program allows for the efficient refurbishment of mobile substations based on the results of a monthly condition assessment required to ensure they are roadworthy and comply with Ministry of Transportation licensing requirements.

The 2008 spending requirement for this program is $1.5 million, which allows for the refurbishment of two mobile substations. The 2008 spending is higher than the bridge year and the historic expenditures, due to a need to replace a failed mobile substations transformer which was not part of the funding required in past years.

Inadequate funding would have an adverse impact on station emergency response and on planned station maintenance capability, and would jeopardize customer reliability.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.1.2 Stations Projects and Demand (Unplanned)

Station Refurbishment Projects

The level of investment required to refurbish a station will vary as a function of the condition of the station. Some stations will require replacement of frost-heaved structures, power equipment components, and/or security fence replacements. In other cases, the work required may be more significant, such as transformer refurbishment or

the complete rebuild of a station on an existing or a new site. The latter may be the case particularly for the older wood pole and timber structure station styles.

Station condition is determined using the ACA process as discussed in Exhibit D1, Tab 2, Schedule 1. About 8 to 15 stations are refurbished annually based on condition, utilization and environmental risks. The number of stations scheduled for refurbishment on an annual basis at this time is currently in the order of 1% of all Hydro One distributing stations. Considering the age of these assets, (i.e. 30 to 40 years) this is a relatively low number of annual refurbishments, largely attributable to Hydro One Distribution's comprehensive maintenance program and a proactive transformer spares management, as discussed in this Schedule and in Exhibit C1, Tab 2, Schedule 2.

Funding levels of this program will impact the amount of breakdown maintenance in future years and negatively impact customer reliability. The 2008 spending for station refurbishment work is $2.5 million. For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

The station refurbishment program also includes the costs associated with refurbishment of spill containment facilities identified through station inspections as requiring work for the purpose of environmental compliance and performance. These projects are managed separately from the larger refurbishment work. The 2008 spending for spill containment facilities is $0.3 million.

<u>Component Replacement & Demand</u>

Component replacement projects involve replacing such defective equipment as reclosers, surge arrestors, fences and switches that have been determined to be at end of life. The condition of equipment and station components is assessed during routine inspections, ACA and during planned and unplanned maintenance activities.

The demand work completed under this program covers the capital component of work required to address the failure of distributing and regulating station components and to correct situations that could cause a power interruption or present a safety hazard. When station components fail, the consequence is typically a service interruption to customers. Station interruptions can impact a large number of customers, typically from 1,000 to 10,000 customers per interruption. Emergency and corrective work must be carried out in a timely manner in order to minimize the risks to customer reliability, and public and employee safety.

This program covers the capital costs of emergency and corrective work at stations that involve plant retirement. Work that does not involve plant retirement is covered under the Sustaining OM&A, Exhibit C1, Tab 2, Schedule 2.

In most cases, smaller components such as reclosers, insulators, connectors, switches, etc. will be repaired, temporarily bypassed, or replaced on site. The failure of a large component, such as a transformer, may require moving the equipment off site and repairing it at a central location and then returning it to that specific site. If a prolonged service interruption is anticipated, service is typically restored through the temporary use of a mobile substation or replacing the failed unit with a spare transformer.

The 2008 spending for both component replacement and demand work is $2.6 million. For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

Summary

The 2008 spending requirement for all Stations Projects and Demand work totals $5.3 million. The proposed funding is within the range of historic expenditures. Spending from year to year can vary as the spending is based on a number of factors, e.g., number

and type of stations to be refurbished, number of failures, condition of assets, asset performance, criticality of assets, availability of spare equipment and local reliability impacts.

Reductions in this program will result in defective equipment and station components remaining in service for longer periods of time, thereby increasing the risk of failure and adversely affecting customer supply reliability. Reduced funding would also increase environmental risks associated with oil entering the environment as a result of an increased likelihood of transformer failures.

2.2 Lines

Distribution lines total 119,900 circuit-km province-wide and are used to deliver power to Hydro One Distribution customers. Lines are constructed on road allowances where possible, or on rights-of-way for which Hydro One Distribution has legal rights to access and occupy. Line components include poles, conductor, transformers, switches, fuses, surge arresters, voltage regulators, capacitors, insulators, reclosers and grounding devices. A small proportion of distribution line inventory is located underground in some of the more urban locations or underwater (submarine) for servicing cottages and residences on islands. The underground and submarine inventory represents approximately 5 % of the total circuit-km.

Sustaining Capital funding for lines includes capital investments required to maintain existing assets associated with overhead, underground, and submarine distribution lines. The work is divided among three programs as noted in Table 3. Funding for 2008 and spending for the bridge and historic years are provided in Table 3 below.

Table 3
Lines Sustaining Capital
($ Millions)

Description	Historic Cost			Bridge	Test
	2004	2005	2006	2007	2008
Trouble Call & Storm Damage (d)	38.3	51.7	90.6	51.7	53.4
Joint Use & Relocations (d)	19.2	22.0	24.0	27.1	23.7
Asset Replacements	35.2	33.2	47.5	60.0	62.4
Total	**92.7**	**106.8**	**162.1**	**138.8**	**139.5**

(d) – indicates this is a demand program

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2.2.1 Trouble Call and Storm Damage Response

This demand program provides capital investment for responding to problems on distribution lines that require immediate attention as a result of trouble calls or storm damage. During 2006, an unusually high number of storms passed through Ontario that caused extensive damage to the distribution system.

A trouble call typically captures the work required to restore the supply of power to customers following an unplanned interruption. However, a trouble call may also be required in response to a customer complaint (e.g. about power quality) or to correct a defect on a distribution asset that, if not addressed, could present a safety concern or potentially result in an interruption of power to customers. Hydro One Distribution must address trouble calls in order to comply with legal and regulatory requirements, to correct known hazardous problems and to maintain reliable electric service in accordance with good utility practice.

The majority of costs associated with trouble calls are incurred in the Sustaining OM&A, Exhibit C1, Tab 2, Schedule 2. In cases where capital plant is replaced as part of a trouble call, all labour and material costs are capitalized under this program. Where a

trouble call is as a result of damage to the distribution system caused by a third party (e.g. motor vehicle accident), Hydro One Distribution will endeavour to recover the cost of making the repairs. Any costs recovered are credited to this program. Historically, damage by third party interference has totaled about $4 million per year with recovery of approximately $2.5 million.

Hydro One Distribution also capitalizes storm restoration costs where a storm results in the replacement of capital plant units and the distribution system experiences significant damage. Storms normally interrupt the supply of power to many thousands of customers. The impact storms have on Hydro One Distribution's system during any given year will depend on the number, type (e.g. wind, snow, ice) and severity of the storms. Historically the number of storms varies widely and the number of days affected by storms has ranged from 20 to over 50 days annually. There is also variation in the number of "force majeure" storms impacting the distribution system, with force majeure defined as a major storm affecting more than 10% of Hydro One Distribution's customers. During 2004, Hydro One Distribution experienced one force majeure storm whereas during 2006 there were eight - an usually high number that caused extensive damage to the distribution system. Given the variability in the number, type and severity of storms, storm-related damage can change significantly from one year to the next

The extent of storm-related damage is also affected by work in other sustainment programs. Reducing vegetation management will increase the likelihood of trees and branches contacting a line under storm conditions as vegetation growth encroaches on the right-of-way and damaged or diseased trees remain near line facilities for longer periods of time. As well, if assets in need of repair or replacement are not addressed, there is an increased likelihood that assets such as poles may fail under adverse weather conditions. All work associated with storm restoration, with the exception of overtime costs and the costs to clear vegetation (e.g. trees, brush) from the storm-impacted distribution lines, are

captured under this program. Overtime and forestry costs related to storm restoration are not capitalized, because these activities do not restore the capital assets to a better condition than existed before the storm, and provides no added benefit to future customers.

The funding level requested is based on an assessment of historical trends in costs and volume of work, taking into account any known factors that could impact historic trends.

The 2008 spending requirement for this program is $53.4 million, net of $2.5 million recovered for third party damage. The 2008 spending is close to that for the bridge year and 2005 actual. The 2008 spending is based on a 4-year average of historical spending with adjustments made to incorporate recent trending in volumes and cost.

The 2008 spending is considerably lower than in 2006, as that was an unusually high year for storm damage. During 2006 the company experienced eight major storms, requiring an unprecedented 36 days of storm damage restoration. Associated with the 2006 storm damage were expenditures of $62 million in capital (compared to a previous range of $14 million to $26 million) and $21 million in forestry and lines maintenance (compared to a previous range of $1 and $8 million). The majority of damage during these storms was attributed to falling trees and branches in close proximity to lines. These storms contributed 57% of SAIDI, and it is expected that the customer outage durations would have been significantly less under the vegetation management program planned for 2008.

Hydro One Distribution’s ability to quickly respond to the significant and repeated storm events in the summer and fall of 2006 resulted in the company winning the prestigious Edison Electric Institute's "Emergency Recovery Award" for outstanding efforts to restore electric service to its customers following such severe storms.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.2 Joint Use and Line Relocations

Joint Use

The joint-use component of this program covers the work required to modify existing Hydro One distribution line assets to accommodate telecommunication or cable television lines, street lighting owned by municipalities, or power circuits for various Local Distribution Companies (LDCs).

Hydro One Distribution carries out joint-use projects in accordance with long-standing agreements between Hydro One Distribution and joint-use partners. The cost sharing provisions in these agreements allow Hydro One Distribution to recover its costs resulting from requests to add new attachments to poles. Historically, 25% to 35% of a joint-use project costs are recoverable. The recoverable portion represents the residual value of the line assets at the time the joint-use project is initiated plus the incremental cost for any modifications required for the new joint-use facilities. The unrecoverable portion of the costs recognizes that these projects generally result in increased life of the facilities that benefit Hydro One Distribution customers, due to a reduction of future investment needs.

All recoverable joint-use costs are paid by joint use partners at the time of the attachment. In addition, annual fees not included in this program are levied per attachment to compensate for on-going incremental maintenance costs due to the presence of these attachments on the pole. Revenues associated with these annual fees are discussed in Exhibit E3, Tab 1, Schedule 1.

The joint-use program is driven by external demand for work, which Hydro One Distribution is required to provide in accordance with existing agreements. The number of joint-use projects has historically ranged from 80 to over 200 projects per year. The variation is due in large measure to communication companies providing or enhancing service to their customers.

Line Relocations

The line relocation component of this program covers the work required in response to road modifications initiated by Provincial and municipal road authorities, or by individuals who require assets relocated for the purpose of developing their property. Hydro One Distribution is obligated to relocate plant at customers' request in accordance with the requirements specified in its Conditions of Service. The relocation of plant to accommodate road modifications must be done in a timely manner as per the requirements of the Public Service Works on Highways Act, R.S.O. 1990, and associated Ministry of Transportation guidelines. Relocations may entail the construction of new plant and the removal of old plant.

The cost of relocation projects is either fully or partially recoverable, depending on the specific circumstances of the project. Typically, a customer requesting a plant relocation must pay Hydro One Distribution for all costs incurred in moving the plant. In the case of projects associated with road relocations, the applicable statute defines the recoverable portion of the relocation work, which is typically 20% to 35% of the total cost. The unrecoverable portion of relocation costs represents the benefit to Hydro One Distribution, and its customers, of having new assets in place that reduce future investment needs.

The number of relocation projects can vary significantly from year-to-year depending on the number of government infrastructure improvement projects and economic conditions influencing individual third party development projects.

Summary

Since the number and scope of joint-use and line relocation projects is variable, the funding level requested for 2008 is based on historic costs, taking into account any observed trending and currently identified joint-use or relocation work.

The 2008 spending requirement for this program is $23.7 million, which is net of $9.0 million in recoverable costs. The 2008 spending maintains the spending during 2006 and is 12% below the bridge year expenditures.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.3 Asset Replacement

Distribution lines asset replacement programs involve replacement of line components and line sections determined to be at end of life, and line modifications to address safety and reliability issues. These projects and programs are closely coordinated and integrated with System Capability Reinforcement plans (Exhibit D1, Tab 3, Schedule 3), where appropriate, in order to maximize the benefits of these expenditures.

The asset replacement work is divided into three programs with funding for 2008, and spending levels for the bridge and historic years, as provided in Table 4 below.

Table 4
Asset Replacement
($ Million)

Description	Historic Cost			Bridge	Test
	2004	2005	2006	2007	2008
Wood Structure Replacement	19.1	18.5	30.3	40.1	39.8
Waste Management Capital*	0.5	0.2	0.2	0.1	1.2
Line Projects	15.6	14.5	17.0	19.8	21.4
Total	**35.2**	**33.2**	**47.5**	**60.0**	**62.4**

* The 2004, 2005 and 2006 costs were for PCB transformer replacements.

2.2.3.1 Wood Structure Replacement

Wood poles deteriorate over time. When the condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions, poles are deemed to be at end of life and must to be replaced to ensure reliability and safety. Planned replacement of poles is much less costly than "emergency" or reactive type replacements, is less disruptive to customers, and eliminates safety issues. Replacing defective poles on a reactive basis not only costs more than planned replacement, but also results in increased overtime with longer outage durations to customers and increased safety risks. There is a strong business need to replace substandard poles before they negatively impact the system.

Over 50% of the distribution system's 1.65 million poles have been assessed since 2002 and about 4% of those poles tested were found to be in a sub-standard condition. The number of sub-standard poles in the system is forecast to be near a historic high and will increase unless the deteriorated poles are replaced. Refer to the Asset Condition Assessment and Analysis, Exhibit D1, Tab2, Schedule 1 for further details concerning the forecast for pole replacements. The need for pole replacements in 2008 is identified

through the pole assessment and testing program carried out under the lines maintenance program as discussed in Exhibit C1, Tab 2, Schedule 2, section 3.2.2.1.

The 2008 funding will permit replacement of 7,000 poles which is an increase from the 5,200 poles replaced in 2006, and the 6,852 poles replaced in 2007. Candidates for replacement are determined through the pole assessment and testing program, which identifies poles that exhibit wood decay, checks and other defects that may jeopardize the structural integrity of a pole. The end of life determination for wood poles complies with the Canadian Standards Association (CSA) criteria for pole strength that specifies replacement when a pole has reached 65% of its original strength. This testing and replacement program maximizes reliability to customers, reduces public safety risks, complies with legal requirements and ensures optimal utilization of the wood pole population.

The 2008 spending requirement for this program is $39.8 million, which is an increase over the historic years. The increase is a result of the number of poles identified to be at end of life as a result of the pole assessment program. Historic expenditures prior to 2006 were in the $20 million per year range with an average accomplishment of 3,000 poles replaced. This compares to the 2008 level of 7000 poles. Year over year historic variations are attributed to variations in the number of poles assessed, and the number remaining to be replaced under this program, taking into account the integration with other programs. For example, sub-standard poles may also be replaced as part of system capability reinforcement and sustaining projects.

Reduced funding of the pole replacement program will increase reliability and safety risks and will prevent Hydro One Distribution from fully meeting due diligence obligations to remove known defective assets that present a hazard to workers and the public.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.3.2 Waste Management Capital Program

The 2008 Waste Management Capital program funds the replacement of waste storage tanks that have been determined to be at end-of-life. The 2008 spending for this program is $1.2 million and is greater than the bridge year and historic years. Expenditures can vary significantly from one year to next depending on the particular need that must be addressed. Prior years' spending was to address PCB contaminated line transformers, as such the nature and need for the work was substantially different than that proposed for 2008, and a direct comparison of spending levels is not appropriate.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.3.3 Line Projects

This program funds the refurbishment of entire feeders or sections of a feeder when the cost of maintaining individual components in the circuit becomes excessive, or a number of components have reached, or are near end-of-life, jeopardizing the reliability of the electrical supply. A decision as to the most appropriate course of action is made in each case taking into account overall condition of poles, wire and cables, condition of associated components, access for maintenance and repair, current and future load requirements and environmental considerations. These projects are further integrated with any system capacity reinforcement plans for the area.

Additional projects funded under this program address significant safety hazards and environmental issues. Specific projects in this category involve the replacement of

submarine cable where the concentric neutral wires have corroded and present a hazard to the public, as well as line modifications to correct hazardous water crossings. The program also funds structural modifications required to accommodate osprey nesting sites where the location of the nest may cause power interruptions.

In addition to the projects noted above, this program funds the replacement of individual line components such as switches, reclosers and wood arms that have been determined to be defective.

The 2008 spending requirement for this program is $21.4 million and is 8% greater than the bridge year. The 2008 spending is 26% greater than 2006 expenditures. These increases are attributed to increased volume of line refurbishment, based on findings from the ACA, and an increase in planned component replacement to manage reliability and safety.

Reduced funding of this program would limit Hydro One Distribution's ability to economically replace integrated groupings of assets identified through ACA. The alternative of replacing individual defective assets when they fail in service would be on a reactive basis and at a premium cost. Reactive replacement would result in more frequent and longer duration outages affecting customer reliability and public and employee safety.
For details concerning projects valued at $1 million or greater, refer to the IJDs in Exhibit D2, Tab 2, Schedule 3.

To illustrate the benefits of sustaining projects, Table 5 below highlights the change in reliability for a number of projects carried out over the 2004 to 2005 period. All of these projects involved replacement of end-of-life components. As can be seen in Table 5 below, the refurbishment projects resulted in appreciable improvements in the number of

feeder interruptions experienced per year and the customer hours of interruption experienced per year.

Table 5: Sample of Distribution Feeder Refurbishment Projects and Associated Reliability Improvements

Number of Feeder Refurbishment Projects	Overall Average Improvement in Number of Interruptions per Year	Overall Average Improvement in Customer Hours of Interruption per Year
8	**52%**	**72%**

2.3 Meters

Meter capital addresses spending requirements for smart meter installations and customer retail meters. Funding for the meters program for 2008 and spending in the bridge and historic years, are provided in Table 6 below.

Table 6
Metering Capital
($Million)

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Smart Meters	-	-	14.1	76.7	164.8
Customer Retail Meters	1.2	1.4	1.6	0.4	2.5
Total	**1.2**	**1.4**	**15.7**	**77.1**	**167.3**

2.3.1 Smart Meters

On June 23, 2004 the Minister of Energy issued a directive to the Ontario Energy Board that establishes targets for the installation of smart meters for all Ontario customers by 2010. Hydro One Distribution's share, based on its proportionate share of customers in the province, is 240,000 by 2007 and approximately 1.2 million by 2010. The planned installation for 2008 is 370,000.

Hydro One is accountable for owning and installing the smart meters, collecting customer metering data over a telecommunications network ("AMRC" and "WAN") to a computer application ("AMCC"), passing the data to the data warehouse of the IESO which has been appointed as the Data Company ("DataCo"), and receiving the data back for customer billing purposes.

Hydro One's plan for the deployment of smart meters has been developed to ensure the highest long term customer value through a vision and a number of operating principles that will protect the investment from early obsolescence, while at the same time recognizing and balancing the inherent risks associated with new technology and large projects. Accordingly, Hydro One Distribution's smart metering plan is to deploy a solution that meets the Ministry of Energy's requirements at the lowest possible cost and is an enabler for other business processes and transformations. In pursuit of this plan, the Company has adopted the following operating principles:

- Develop and deploy an end-to-end architecture for both information technology and communications infrastructure that recognizes long term business needs and provides a migration path from the minimum requirements of a smart meter system;
- All hardware and devices will conform to industry standards and will be based on open architecture design (i.e. to the extent possible use non-proprietary applications);

- Material development will not occur until all, including third party, requirements are understood; and,
- A staged implementation will be deployed across all work streams to mitigate risk. This includes Advanced Metering Infrastructure ("AMI") technology, business process design, systems development and integration and customer communications.

With respect to its smart metering program, Hydro One Distribution has participated in or been affected by the following proceedings since late 2004:

- RP-2004-0203/ EB-2005-0198 – On March 17, 2005, the Board approved Hydro One Networks' plan for CDM, in which $7.8 million was allocated to smart metering to address initial start-up costs and deployment.
- EB-2005-0529 – The Board's Decision on Generic Issues respecting Smart Meters, issued March 21, 2006, which approved a $0.30 meter cost per residential customers per month, to be recovered through their monthly service charges, beginning May 1, 2006.
- EB-2006-0246 – Hydro One Networks Inc.'s Smart Meter Plan - 2006-2010 was submitted on December 15, 2006, according to the Board's Smart Meter Filing Guidelines and Requirements, issued October 26, 2006.
- EB-2007-0542 – The Board's Decision on Hydro One Networks' 2007 Distribution Rates issued April 21, 2007, approved an amount of $0.93 per month per metered customer, beginning May 1, 2007.
- EB-2007-0063 – Combined Proceeding on Smart Metering was initiated by the Board on May 18, 2007, to determine the prudence and recovery of costs associated with smart metering activities for 13 distributors, including Hydro One Networks Inc., which under the Regulations, are licensed to conduct discretionary metering activities. The Board's Decision was released on August 8, 2007. The Board determined that the purchasing decisions of the thirteen utilities involved in this

proceeding were implemented with the necessary due diligence and the terms of the contracts are prudent. The Board also allowed the cost of installation using internal staff and agreed the cost of installation in rural areas will be higher. The Board agreed with the overall costs incurred to May 31, 2007 related to the minimum functionality of all installed meters other than the cost of capital associated with project management – in this areas the Board disallowed half of the requested amount and provided Hydro One the opportunity to justify this remaining amount in this hearing. The justification of this amount is provided in Exhibit F1, Tab 1, Schedule 1.

As a result of these decisions (particularly the latter two), Hydro One Distribution's smart meter plans, including its assessments of minimum functionality and the required architecture, procurement process, contracts with vendors, plans for smart meter deployment, risk assessment and mitigation plan, and associated costs, have already been provided to the Board and will not be repeated in detail here.

The smart meter program is proceeding well. During 2006, Hydro One Distribution was able to pilot its meter installation process (with 28,000 installations) and automation tools, and to develop unit costing for mass market deployment. Statements of work and contracts were developed with the selected major vendors, which enabled detailed pricing for the majority of the products and services required. Total meter deployment from 2006 through 2007 is projected to meet the Company's target of 240,000 meter installations by the end of 2007. Other activities, such as installation of the network communications infrastructure are progressing. The "back-office" infrastructure and process design is underway and initial results from meter communications reliability testing are promising.

Hydro One Distribution's capital spending requirement of $164.8 million in 2008 reflects the continuing deployment of smart meters throughout its service territory. The related activities encompass both minimum and incremental functionality work:

- Activities associated generally with the government's regulations concerning minimum functionality, which account for $64.2 million and $136.5 million in 2007 and 2008 respectively, include the following work:
    - Installing additional smart meters and advanced metering communications devices ("AMCDs");
    - Building and expanding the advanced metering regional collector ("AMRC"), and underlying networks to accommodate an increasing number of meters coming on- stream; and
    - Commissioning and placing into service, hardware and software for the advanced metering control computer ("AMCC") to enable it to communicate and transmit quality meter data to and from the meter data management and meter data repository (MDM/R) and the Company's CIS.
- Incremental functionality activities associated with effective use of the smart meters to provide time-differentiated billing to customers and provide Hydro One the ability to leverage its AMI system for other business benefits, which account for $12.5 million and $28.3 million in 2007 and 2008 respectively, include the following work:
    - Upgrades to our CIS system to provide for Time of Use billing and related required settlement changes. This aspect of the Smart Meter program is rooted in the government's desire and directive to create a conservation culture of which time of use rates are an integral part;
    - Integration of the end to end systems including business process redesign, This integration ties the AMI systems implemented under minimum functionality with the IESO's MDMR and Hydro One's CIS system to

allow the collection of time differentiated consumption data required for TOU billing; and,

- The added cost of super capacitors in meters and batteries in the regional collectors (AMRC) that provide for real time outage reporting after and during loss of power. Having the ability to pin point outages and tie this information to our outage management system has the potential to increase customer service and reduce costs. When outages occur, especially during a major storm, there are instances where faults and damage are "nested". In these situations, without the knowledge of the state of individual services, it takes longer to locate outages and it is possible for crews to fix a problem and leave the area only to return to fix other problems downstream. This is inefficient and extends outage times. Since Hydro One is changing all its meters by 2010, this provides a good opportunity to deploy this functionality effectively.

- Project management activities associated with the overall smart meter program, which account for $2.4 million and $0.1 million in 2007 and 2008 respectively, are included in the costs above.
    - Due to the scope, complexity and specialized nature of the above tasks, the project management services and operation of a project management office (PMO) is provided by Capgemini. Capgemini was selected as the system integrator for Hydro One's smart meter program through a competitive RFP process in 2005. Although Hydro One is providing overall direction to Capgemini, the project management services and PMO are typically provided by the system integrator and is not a role that Hydro One is able to resource internally. Additional details on Capgemini's project management function are also provided as part of the

discussion in Exhibit F, Tab 1, Schedule 1 on smart meter Regulatory Asset accounts.

- The project management costs drop off in 2008 as the bulk of the PMO work Capgemini was engaged to do is planned to be largely complete by the end of 2007.
- The total project management costs incurred to the end of 2008 are forecast to be about $5 per installed smart meter unit. This is a substantial drop from the unit cost of $21.7 per installed smart meter unit reflected in the combined smart meter proceeding when the project management costs incurred to date were spread over the 62,194 units installed to the end of May, 2007.

The 2008 expenditure level is an increase over that of 2007, reflecting the higher number of planned meter installations of 370,000 in 2008 compared to 212,000 in 2007. Further details on this program are provided in the IJD in Exhibit D2, Tab 2, Schedule 3.

A reduction in the requested funding would compromise the Company's capability to deliver its planned results for 2008. These would include the installation of an additional 370,000 meters, continued development of the communication network needed to support the installed meters, modifications to the core systems to support TOU billing and the required re-engineering of business processes. Loss of this capability would severely jeopardize Hydro One's capability to meet the ambitious targets which have been set by the government.

2.3.2 Customer Retail Meters

The sustaining capital retail meter program includes the installation of meters at shared distribution stations, customer initiated meter upgrades, meter conversions at the acquired

LDCs, and sustainment of the retail meter inventory. Each of these initiatives are discussed in detail below.

The largest initiative during 2008 is an expenditure of $2.0 million related to the Company's installation of new meters at shared distribution stations. This expenditure is required to improve metering associated with Low Voltage facilities. For additional details, refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

Meter upgrades are a customer-driven initiative. As required by the Distribution System Code, Hydro One Distribution upgrades an existing customer’s demand meters to interval meters when their average annual monthly peak demand is equal to or greater than 1,000 kW. Hydro One Distribution's policy for new customers requires installations of interval meters if their average annual monthly peak demand is forecast to be greater than or equal to 200 kW. As well, Hydro One Distribution is planning to upgrade non-standard meters at acquired LDCs. In total, the spending for these initiatives is $0.4 million.

The Retail Meter Inventory Sustainment Program is required in order to efficiently replace in-service meters that fail, are obsolete, or that cannot be returned to service through the re-verification program. The historic level of about 2,000 new meter purchases annually need not continue in 2008, as the Smart Meter Program will cover the cost of replacing failed or obsolete meters. However, about 80,000 meters which do not qualify for smart meter replacement, still require an adequate inventory, with about 100 new meter purchases per year. The total spending for this initiative during 2008 is $0.1 million.

The 2008 spending requirement for this program is $2.5 million. This proposed funding level is $2.1 million higher than that for the bridge year and $1.1 million higher than the historic average. The increase is mainly due to the need to fund the new meter

installations at shared distribution stations. These increases are offset to some degree by savings from the lower inventory of electro-mechanical meters required as a result of Measurement Canada's dispensation on meter testing ad verifications through the implementation of the smart meter program.