Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0680

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

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2008, May 1, 2009, and May 1, 2010.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

David Balsillie
Member

DECISION

May 15, 2008

Table of Contents

1. The Application and the Proceeding

Toronto Hydro-Electric System Limited (THESL, the “Company”, the “Utility”, or the “Applicant”) distributes electricity to 678,000 customers in the City of Toronto. A 100 percent-owned subsidiary of Toronto Hydro Corporation (“THC”), the Applicant is the successor to the six former hydro-electric commissions of the municipalities which amalgamated on January 1, 1998 to form the City of Toronto. THC, the Applicant and other affiliates of the Applicant were incorporated under the *Business Corporations Act* (Ontario) on June 23, 1999. The sole shareholder of THC is the City of Toronto

The Applicant filed an application dated August 3, 2007 with the Ontario Energy Board (the “Board”) under section 78 of the Ontario Energy Board Act, 1998; S.O. c.15, Schedule B) (the “Act”), for an order or orders approving just and reasonable rates and charges for three individual and successive rate years, commencing May 1, 2008, May 1, 2009, and May 1, 2010.

The application included increases in operating expenses, increases in capital expenses, impacts from changes to the debt:equity structure to comply with Board policy, changes to the cost of debt and equity, as well as the costs of plans for Conservation and Demand Management (CDM) and smart meters. The Applicant also proposed disposing of certain deferral accounts and requested new deferral accounts. The Board assigned file number EB-2007-0680 to the application. Updated evidence was filed on November 27, 2007.

The application was for approval of distribution rates and other charges to recover $524.7 Million for 2008, $555.7 Million for 2009 and $586.7 Million for 2010.

The intervenors to this proceeding are listed in Appendix B. A Settlement Conference was convened on Tuesday November 20, 2007. The Settlement was presented to the Board on Friday, November 30, 2007. There was an agreed settlement on cost of capital issues. Partial settlements were reached on some of the other issues, but most issues remained unsettled. The Settlement Agreement is attached as Appendix C. The Issues List and each issue’s settlement status are presented in Appendix A.

The oral hearing commenced on Monday December 2, 2007 and was completed on December 11, 2007. The argument phase was completed on February 15, 2008.

The full record of the proceeding is available at the Board's offices. The Board has chosen to summarise the record in this Decision only to the extent necessary to provide context to its findings.

2. The Threshold Question

The Applicant's proposal consists of a request that the Board approve rates in each of rate years 2008, 2009 and 2010, based on a cost of service review for each of those years. To support its proposal, the Applicant has filed evidence which it considers to be cost of service evidence for each of the years. That evidence is predicated on a series of forecasts respecting all areas of its operation and business environment covering the three years.

The Applicant's proposal consists of a request that the Board approve rates in each of rate years 2008, 2009 and 2010, based on a cost of service review for each of those years. To support its proposal, the Applicant has filed evidence which it considers to be cost of service evidence for each of the years. That evidence is predicated on a series of forecasts respecting all areas of its operation and business environment covering the three years.

None of the Intervenors supported the Applicant's proposal.

In its Issues Decision, the Panel decided that the evidence for the three-year application should be heard, but the Applicant was specifically cautioned that the Board's Decision to hear the evidence for rate years 2009 and 2010 should not be seen as any indication of how the Board would determine the question.

This multi-year proposal deviates from the Board's current multi-year rate setting plan, which begins with rates based on a cost of service review for the first year followed by a mechanistic rate adjustment for subsequent years. After that, a new cost of service based application would be expected to be used to rebase the rates and the cycle then would be repeated.

The Applicant states that one of the key drivers underpinning its request for a three year cost of service approach is the concern that conformity with the Board's multi-year plan would cause it to expend significant internal resources on regulatory issues such as rate applications.

It asserts that another driver for the request concerns a loss of perceived “momentum” for infrastructure renewal across the Utility, which would arise if the Board's plan were to be implemented.

In the Board’s assessment, a most significant element of the approach advanced by the Applicant is that all areas of spending become subject to forecasts which extend beyond a single year into second and third years, which are themselves predicated on forecasts. This is a rather uncertain structure, where one forecast builds upon, and is limited by, the vagaries that are an unavoidable aspect of any forecast. While the Applicant has stated in its Reply Argument that it accepts the risks associated with its forecasts, in the Board’s opinion, that is not strictly accurate. If the forecasts are higher than actual spending, ratepayers will be paying rates higher than they should. This risk is somewhat pointed, given the fact that the Applicant’s proposal contains requests for very sharply increased spending in each of the three years.

The Board’s multi-year rate setting plan has been designed to create just and reasonable rates with as minimal a regulatory burden as possible. Its key features are simplicity, reliability, transparency and predictability. Any approach taken by an Applicant that varies from that plan should meet these criteria as effectively as the Board’s plan.

In the Board’s opinion, the Applicant’s proposal does not meet a number of the key elements of its multi-year rate setting plan.

First, multi-year regulation seeks to balance ratepayer and shareholder interests through the imposition of explicit productivity goals. This means that the multi-year plan should encourage productivity improvements within the Utility, and should ultimately share those gains with the ratepayers. In the Board’s plan, this is accomplished through the use of an offsetting productivity factor (the X-factor), which provides a sharing of the benefit of efficiency gains to ratepayers immediately.

The Board simply could not see any discernable productivity driver within the Applicant’s proposal. That is not to say that the Applicant is not concerned about productivity, but simply that there is no transparent reflection in its multi-year rate plan that addresses the issue. The Applicant’s plan contains steady increases in spending in each of the three years, but there is no explicit or measurable incentive to productivity, nor any mechanism which would capture such gains in any year over the period.

Second, multi-year regulation should provide for a timely review of the extent to which the company is performing to its forecasts. Under the Applicant's proposal there appears to be no check as to the accuracy of its forecasts until the year following the last year of its program; namely, 2011. While this is not problematic under the Board's plan where rates based on one year's forecast are subject to a formulaic adjustment which includes the productivity incentive, here the Applicant has based its proposal on forecasts, each dependent in some measure on the previous year's forecast, with the result that each additional year's forecast is subject to increasing uncertainty.

Third, as the Board noted in the Hydro One Networks Inc.[1] case, a time of rapidly increased spending, whether such spending is by way of capital expenditure or current expense, is not a time where regulatory oversight should be diminished. If the Applicant's proposal were to be accepted, there would likely be no regulatory oversight until Spring 2011, in conjunction with a new cost of service based review to establish rates for that year.

The Board notes that the Company has filed this application, at least in part, to limit the "regulatory burden" experienced by the Company over the next while.

The Board's multi-year rate setting plan was formulated so as to use Utility and Board resources as effectively as possible. The effective use of all parties' resources was a key driver in the development of the Board's IRM plan.

The Applicant has chosen to advance its proposal, which involves a considerably more complex structure and forecasting paradigm, which has had the effect of stretching its resources, as well as the resources of other parties, ostensibly to avoid undue regulatory burden.

As a regulated monopoly, a core element of the Utility's business is its engagement with the regulatory process.

The Company will want to integrate the regulatory environment fully into its operations, and not consider it to be an artificial obstacle to the Company's pursuit of its business goals. Compliance with and participation in the regulatory process needs to be built into its processes, not grafted onto them.

[1] Hydro One Networks Inc. EB-2006-0501

As this Decision demonstrates, the Board is prepared to approve reasonable proposals, provided they meet the Board's statutory mandate and its obligation to balance the interests of consumers and the industry.

In considering the evidence in this case, it became clear that the Applicant considered itself to be straining against a perceived unreasonable regulatory burden. The Company has described this as "regulatory distraction".

The Company will benefit from the organization of its processes so that preparation of conventional cost of service applications doesn't place an undue burden on its people or resources. Such preparation can and should be part of the ongoing business process within the Utility, and its document and information management systems.

Accordingly, the Applicant's multi-year plan will not be approved as proposed.

However, there are some factors which lead the Board to consider that granting the Applicant two years of its cost of service application, that is for 2008 and 2009, may be an effective regulatory approach, provided there are sufficient mid-term updates reflecting its performance relative to its forecasts, and productivity gains.

First among these factors is the realization that as of the date of this Decision, the form and content of the 3rd Generation Incentive Rate Mechanism have not been finalized. Some of the key elements of that program are still undetermined. For example, one of the key discussion points in the consultation concerns the extent to which the mechanism will adopt a methodology to capture capital spending within the IRM term, either through an integrated capital module or by way of Z-factor treatment for extraordinary capital spending budgets.

The same can be said of the development of the productivity factor for the 3rd Generation IRM program. This is a key element to the program, and one upon which there are highly divergent views among stakeholders.

This Application reflects significant capital spending plans, over an extended period. It also contains OM&A spending plans which exceed by a considerable margin historical norms. The productivity associated with these spending plans was a pointed issue in the proceeding.

It seems inappropriate to restrict the Applicant to a single year cost of service format in the expectation of a 3rd Generation IRM program that is still in formative stages with respect to key elements of the Company's spending plans and for which there is tested evidence beyond just 2008.

In addition, and most importantly, the Board finds elsewhere in this Decision that the Applicant has been able to demonstrate a need for measures to address what has been a material underinvestment in infrastructure over the recent past. This evidence, which consisted of third party reports, and testimony by Company witnesses, established that there are legitimate concerns respecting the condition of certain important elements of the asset base, particularly underground cable and certain transformer stations.

In light of this evidence the Board has approved a sharp increase in spending for the specific purpose of bringing the plant into better overall profile. In such circumstances, the Board considers that the most appropriate approach to take to ensure that this initiative progresses is to provide for funding over a two year period.

The Board will require the Applicant to provide a detailed report respecting its progress on this project to be filed at the time of its next application dealing with rates beyond the test period dealt with in this proceeding.

Accordingly, the Board will approve rates for 2008, and 2009 based on its consideration of the evidence filed with respect to each of these years. We anticipate that the rates for the subsequent year will be determined through the application of a formulaic adjustment using the then Board-approved methodology.

As noted above, the Application does not contain any explicit evidence with respect to productivity gains achieved or anticipated. In approving rates for the second year on a cost of service basis the Board is mindful that the Company does not have any explicit or transparent productivity driver for this period. Addressing this deficiency through interim reports or some similar mechanism would, in the Board's view, be unwieldy and cumbersome.

The Board expects that the Company will develop the ability to track productivity gains throughout its operations in a programmatic manner that will appropriately inform its next rebasing application.

3. Capital Budgets and Rate Base

A summary of the proposed capital budgets for 2008 and 2009 are shown in the table below, as are capital expenditures ("CAPEX") for 2006 and 2007 for context.

Table 1
Summary of Capital Budget ($000s)
Exhibit D1 Tab 7 Schedule 1, page 10

	2006 Historical	2007 Bridge	2008 Test	2009 Test
Sustaining Capital				
Underground Direct Buried	7,327	31,961	45,424	54,565
Underground Rehabilitation	33,112	31,327	30,514	27,188
Overhead	19,040	22,703	17,339	18,912
Network	5,625	3,996	4,514	6,187
Transformer Station	745	9,377	9,304	10,673
Municipal Substation Investment	5,977	7,008	8,090	6,454
Sub Total Sustaining Capital	**71,826**	**106,372**	**115,185**	**123,979**
Distribution System				
Reactive Work	11,094	14,866	15,550	15,514
Customer Connections	36,400	34,400	36,360	37,383
Metering	1,517	8,057	12,964	16,539
Smart Meter	3,614	-	36,207	34,567
Engineering Capital	20,960	23,195	26,417	27,051
Capital Contribution	(23,632)	(19,633)	(19,600)	(19,600)
Asset Management	2,600	300	5,650	10,670
Total Distribution System	**124,379**	**167,557**	**228,732**	**246,103**
General Plant				
Information Technology	15,210	20,911	27,706	27,227
Fleet & Equipment Services	6,212	8,640	8,771	8,196
Facilities	5,689	13,770	25,340	17,792
Other (Gear, SCADA, CIS, Banner)	4,861	3,228	300	100
Total General Plant	**31,974**	**46,549**	**62,117**	**53,315**
AFUDC		2,274	3,325	3,914
Capital Recoveries	(1,581)	(4,061)	0	
Miscellaneous	2,631	1,120	210	(1,825)
Total Expenditures	**157,403**	**213,439**	**294,384**	**301,507**
% increase compared to 2006			**87%**	**92%**

The issues addressed in this chapter are: sustaining capital; information technology; metering and smart metering; regulatory treatment of vehicles for personal use; and, proceeds from sale of assets.

3.1 Sustaining Capital

Sustaining Capital is the largest part of the Applicant's CAPEX increases for the test years.

The Applicant has undertaken 3 diagnostic studies on the condition of its assets and has filed the reports of these studies as part of its evidence. These include:

- Asset Condition Assessment Study by Kinectrics;
- Cable Condition Study by Mr. Paul Densley (ArborLek); and
- The Applicant's Internal Cable Condition Assessment by Mr. Kahn (collectively the "studies").

In addition to asset condition, the Applicant replaces assets because of obsolescence, safety issues, plant relocate requirements, and to improve overall network flexibility and functionality within its service territory.

The studies show that most assets are in "good" or "very good" condition; however, a few specific asset classes may be deteriorating faster than they are being replaced, and these require more immediate actions beyond routine maintenance. The Company's evidence was that during the 2008 to 2010 period, it would be addressing only those assets that are either in the "poor" or "very poor" categories. The Kinectrics report recommended that the assets characterized as "very poor" be replaced over the next 2-3 years and that the assets in "fair" condition be planned for replacement in four to ten years, since it is anticipated that the assets now in "fair" condition would fall into the "very poor" by the end of that period.

The major areas where rehabilitation is needed, and where the majority of expenditures are planned, are the categories of "Underground Buried Cable" and "Station Transformers". The Kinectrics report indicated that 32 Station Transformers were in "poor" or "very poor" condition. The Company's internal assessment recommended that 6 of those transformers ought to be replaced in each of 2008, 2009, and 2010. The Kinectrics study suggested that there are 777 circuit km of Direct Buried Underground

Cable near end of life, while the Applicant internal staff assessment recommends that 599 conductor km of this cable be replaced between 2007 and 2009.

Evidence was presented showing that there is an increase in outages as reflected in the Applicant's System Average Interruption Frequency Index ("SAIFI"). The main cause of power interruptions to customers is "defective equipment". In 2006, the Applicant's defective equipment contributions to SAIFI were almost double the national average. However, the Applicant's Service Quality Measures, as measured by reported Customer Service Performance Indicators[2] , are well above the service standards from 2001 to 2006 (except for Emergency Response in 2002).

In the Applicant's view, such information on system reliability, combined with information on the age of various assets and the studies of the condition of the Applicant's distribution assets, demonstrate a need for increases in spending for sustaining capital.

The Applicant has concluded that replacement is more prudent than repair of its aging infrastructure in many cases. In reaching that conclusion, it relied upon the asset studies and a software program called "Asset Investment Strategy", which assists in evaluating and prioritizing investments.

A number of concerns were raised by Intervenors and Board staff with regard to the planned capital replacement program. These concerns include:

- It appears that the capital replacement program was developed prior to the completion of the studies;
- Many of the consultants' recommendations, considering the timing of asset reviews, were not used in developing the capital budgets for the three year plan;
- The criteria used to categorize the condition of the assets may not have been comprehensive;
- No further diagnostic testing is planned (2008-2010);
- Data gaps and inconsistencies;
- Confusion about such items as cable types and distances between transformers; and
- Diagnostic testing programs and rejuvenation methodologies may not have been adequately explored or utilized

[2] Exhibit B1/Tab 13/Schedule 1

The Applicant states that it would be undertaking further testing, as suggested in the consultants' studies, to help focus replacement beyond 2010. It intends to investigate cable rejuvenation and diagnostic testing to define more precisely the requirements of the cable replacement problem beyond the test years (i.e. once replacement of currently-identified "poor" and "very poor"-condition cables has been largely completed).

The Applicant maintains that if the CAPEX budget were not provided in full, then the OPEX budget requirements would escalate due to the increased amount of maintenance that would be required.

With regard to implementation of the capital plan, the Applicant's witness described the Applicant's Enterprise Resource Planning ("ERP") process which derives, among other things, the number of hours available for work during a test year as compared to the number of hours needed to implement capital programs. The Applicant witnesses confirmed to the Board that, in addition to its own employees, it is confident that it can acquire the contract services necessary to implement certain aspects of the capital plan over its proposed test year period. The contract work represents a substantial portion of the sustaining capital program in 2008, and tapers off in 2009. This staging is both appropriate and technically necessary. It also provides the Applicant the opportunity to hire and train new additional employees sufficiently to become engaged in the work of installing and connecting plant that is not yet "live".

VECC pointed out that large increases in CAPEX and OPEX for 2008 are added to the significant increases made to CAPEX and OPEX in 2007; the 2007 increases have not been examined or approved by the Board. The end result is the 2008 revenue requirement reflects significant increases in spending which may or may not be warranted. VECC proposes that a Deferral/Variance account be established for sustaining CAPEX. VECC recommends that the Board approve the 2008 Capital Budget, subject to the sustaining capital budget over- or under-runs being tracked through the variance account for disposition in a subsequent proceeding.

SEC agrees that the budget for cable replacement should be approved, however, it asserts that the Applicant should be required to submit additional evidence to demonstrate that it has done further diagnostic testing and considered alternatives to full replacement of the cable assets.

SEC also recommends that a Variance Account be established for these expenditures within the test period, since the Applicant has proposed a large capital expenditure that is far in excess of its past level of expenditure. In SEC's view, there is a high probability that actual expenditures will differ from the forecast. SEC was also of the view that the Variance Account approach would protect ratepayers from paying for assets that do not come into service.

Board staff suggested that the Applicant has not adequately explored alternatives to full replacement, such as improved diagnostic testing and partial replacement.

The Applicant argued that as it has a strong interest in being able to manage its capital program professionally and in being able to deploy resources advantageously, the proposed asymmetric, zero-dead band variance account proposed by SEC for sustaining capital expenditures should not be adopted.

Board Findings

The proposed budgets must be viewed in the light of the resolution of the "Threshold Issue" to allow the Applicant to rebase for 2008 and 2009. There is no doubt that the proposed levels of capital expenditure are considerable. From the evidence that has been presented, the physical assets of the distribution system have a significant component that are in the "end-of-life" category and have been classified by Kinectrics as either "poor" or "very poor". Many parties acknowledge that parts of the Applicant's network, built from the 1950s to the 1980s as Toronto and its suburbs grew, are aging and in need of repair or replacement. There is a common recognition that the Applicant must accelerate capital expenditures to some extent. It is important to acknowledge that the Applicant, like every other utility in the province, has had to weather considerable uncertainty in its operating environment brought on by changes in regulatory direction since market opening in 2002. There have been periods of rate freeze and other somewhat unexpected and anomalous circumstances. These changes were not of the Applicant's making, and the Board recognizes that they may have complicated its response to emerging issues, such as equipment assessment, repair and replacement.

In other recent Board decisions, and elsewhere in this Decision, the Board has emphasized the importance of placing spending proposals within historical norms. The guiding principle is that extraordinary spending proposals must be supported by compelling evidentiary support which is commensurate with the extent of the increases sought.

In large part, the various studies referenced earlier establish the need for a substantial increase in sustaining capital spending. However, there are some other considerations: for example, ratepayers are entitled to expect that Utility management has an ongoing strategy to address equipment condition issues year over year. This is as true of years prior to rebasing as it is within rebasing years. In the years since amalgamation the present utility is expected to have been anticipating equipment condition issues in a manner calculated to smooth spending and ensure reliability of the system. Indeed, the present utility cannot point to the inadequacies of its constituent utilities, or the uncertain operating environment referred to above as a complete explanation for its inability to anticipate the equipment condition issues highlighted by Kinectrics.

Further, the Kinectrics report, while categorizing certain assets as falling within the “poor” and “very poor” rating, stops short of identifying replacement as the only option available to deal with them. It also suggests that further testing, and different kinds of testing, may serve to refine some of the characterizations it has made, which may lead to more latitude in the replacement strategy.

The Board therefore will approve 80% of the requested amounts in the sustaining capital budget for each of 2008 and 2009. These substantial increases will allow the Company to execute its program, but also take into account the other very significant and demanding efforts to be undertaken by the Company within the next two years as for example in the areas of IT upgrades, and facilities changes.

This reduction recognizes that the replacement strategy may not be the only option, and that enhanced assessment and testing may lead to retention of some assets now planned for retirement. The fact that the capital budget was completed without full input of the external experts also suggests that something less than the full budgeted amount will be sufficient to allow the Company to address its asset condition issue in the test period. The Board also is concerned that the failure of the Company to adequately address this issue before now has created a situation where lumpy spending is needed. Wherever possible, utilities should act so as to avoid the kind of extensive catch-up program described in the Company’s proposal.

The Board finds that the establishment of a Variance Account is not the appropriate method to track and assess the Company's progress in effecting the very ambitious programs outlined in the evidence.

Instead, the Board requires the Company to provide a report reflecting its progress in its replacement and maintenance programs for its underground cable replacement and plant replacement program, to be filed at the time of its next application dealing with rates beyond the test period dealt with in this proceeding. In subsequent rate cases, the Utility must be in a position to provide asset condition studies and other analyses that support its capital strategies and budgets. The Board expects that the Applicant will undertake appropriate studies and analysis to address the questions concerning its asset management practices that have been raised during this proceeding, including options for increased diagnostic testing, rehabilitation versus replacement, and better identification of situations where replacement in its distribution network (both in the nature and location) of the assets is needed in whole or in part.

The quality of the subsequently obtained information should improve as the Applicant upgrades its information systems, facilitated in part by IT expenditures approved in this Decision.

The Board expects that the Applicant will support any subsequent cost of service or capital expenditure application with appropriate studies. At a minimum, an Asset Condition Assessment study that is integrated into the Applicant's asset management plan and budget cycle which evaluates various cost-effective alternatives for refurbishment, replacement or rejuvenation approaches should be filed.

3.2 Information Technology

The Applicant has proposed major increases in the Information Technology and Services (IT&S) component of its budget for the test years. In its pre-filed evidence, the Applicant provided a summary of its recent history as a context for these proposed increases.

During the amalgamation of the former municipal utilities (1998-2000), there were rapid changes in the organizational structure, technologies and handling of Y2K-associated risks. The focus was to maintain stability amidst the first wave of integration. During the so-called "consolidation phase" (2001-2003), the electricity industry as a whole faced a new challenge around the retail initiative and the technology changes required to prepare for market opening.

Additionally, for the Applicant, in late 2000 the business transformation initiative started with the implementation of the Enterprise Resource Planning system "Ellipse". In what the Company describes as "the stabilization period" (2004-2005), it was necessary to absorb the high rate of change introduced previously, with an emphasis on operations and stabilization of systems; the integration of key systems like the Supervisory Control and Data Acquisition ("SCADA") system, the Geographic Information System ("GIS"); and the Distribution Management System ("DMS").

The modernization period began in 2006 with the appointment of a Chief Information Officer and the development of a new IT&S direction, including a number of initiatives aligned with the Applicant's strategic objectives, a restated IT mandate and an assessment of the risks of the current situation within the division. The Applicant stated that one of the components of its approach is a three-year program (2007-2009) to implement a best practices framework. This is described by the Company as Control Objectives for Information and related Technologies ("COBIT"). The Company also states that COBIT is an IT industry standard which provides a comprehensive framework and processes for the management and delivery of high quality IT-based services; and the management and delivery of projects, services and major commitments against budget and project scope.

In order to operate the various systems efficiently and effectively, the Applicant pointed out that the importance of building a sound architecture, based on a Service Oriented Architecture ("SOA"), cannot be overstated. Today, the core systems of the Applicant do not share a common architecture for communication or integration, resulting in many point-to-point interfaces between applications. In the Company's view, the SOA initiative is highly strategic as the key enabler of many critical systems and business processes.

The Applicant proposed an increase in information technology assets from $137.1M in 2006 to $245.7M in 2010 (an increase of $108.6M or 79.2%). The increase is primarily due to the following activities:

- Control Centre Consolidation;
- Outage Management System;

- Distribution Management System;
- Customer Information System upgrade;
- Security Office Establishment; and
- Core Legacy Application upgrades.

IT capital investments were $15.2M in the Historical Year (2006) and $20.9M in the Bridge Year (2007). The Applicant is proposing IT capital expenditures in the Test Years of $27.7M in 2008 and $27.2M in 2009[3]. If the O&M costs are added to the capital expenditures, the totals are: 2006 (actual) - $37.8; 2007 (bridge) - $47.4M; 2008- $56.2M; and 2009 - $56.7[4].

The Applicant contended that this increased spending over the test years supports a multi-year program aimed at improving business productivity. The Applicant testified that in order to achieve the full benefits of the IT investments, it is necessary to build on the infrastructure platforms implemented in the first year in the second and third years. The Applicant will also be upgrading its core legacy systems to eliminate outdated applications (e.g. Windows 2000, Office 2000) and standardize current versions of software.

The Applicant acknowledged that it had not followed the normal business practice of refreshing hardware and software in the years prior to 2006. The Applicant also acknowledged that, although there would be staff savings resulting from the implementation of the Business Intelligence System, there would be no IT staff reductions since the productivity gains would be applied to new business systems that require more IT staff.

Intervenors challenged the IT spending proposal. There were suggestions that general capital including IT should be held at historical levels consistent with customer growth.

In reply, the Applicant reiterated the necessity of its proposed spending, stating that it must move forward with these IT projects in order to replace expired and unsupported systems and move to current versions to ensure ongoing maintenance, vendor support and software upgrades. It also indicated that it is implementing other productivity and service enabling systems and an IT governance framework to ensure the optimal deployment of systems to enable the Applicant’s employees to deliver service and

[3] Exhibit D1/Tab 10,/Schedule 2-1, p. 5, Table 1
[4] Exhibit F2/Tab 10/Schedule 1

productivity improvements to its ratepayers. The Applicant maintained that its IT programs are integrated with operations and other projects to prudently support business requirements, and that its IT projects are supported by business cases.

Board Findings

The Board notes the Applicant's evidence that, in the years prior to 2006, the normal business practice of refreshing the IT hardware and software was not undertaken. There are various factors, such as amalgamation, industry restructuring, and legislative and regulatory changes which may have impacted the Applicant's prioritization of the funding and execution of these upgrades, at least in part. While most Ontario distributors were also impacted by many of these same factors the integration of disparate operational and information systems of the former municipal electrical utilities may have made this a greater challenge for the Applicant.

This leaves the Applicant in a position of having to upgrade its legacy systems, plus its management and operational systems, in short order. All of the proposed projects are presented in detail in the Company's evidence. Individually, these projects are well-constructed and make considerable business sense. Collectively, there is a high cumulative cost and an intensive human resources effort required if all of these programs are to be implemented as planned. The capital investment increase in IT from 2006 to 2007 represented a 37.5% increase in funding. The proposed capital investment increase for 2008 represents a further 32.5% increase to $27.7M, a total increase of 82.2% over a two year period, before stabilizing and decreasing.

The Board has noted the arguments of the intervenors who are concerned that such large expenditure increases cannot be fully justified in the short term.

The Board notes that the Applicant has many other capital and operational projects planned for the test years, and its capital budget represents a significant increase from historical levels. These increases are in a number of areas, and a number of these programs are multi-year in nature.

One specific project that is being implemented by the Applicant is the consolidation of its operations centers, going from seven in 2006 to three over a number of years. The consolidation is expected to result in operational efficiencies and to facilitate communications among the Applicant staff. However, the consolidation will not be completed in the test year period, and the Applicant is leasing facilities and relocating staff over the period. While the Board sees the need for the Applicant to address its underinvestment in IT assets, it is not convinced that the Applicant's proposed IT projects are fully justified during this period of operational reorganization and change.

As in all other areas of proposed spending increases, the Board looks to the Company's historical spending norms as a guide. The apparent underinvestment in this area over the recent past ought not to be used as a springboard for sharply increased spending now. The Company must, to some extent, live with its prioritization over the recent past; and customers are entitled to protection from lumpy spending plans that could have been, and should have been, avoided if appropriate measures had been taken earlier. This is as true of this aspect of the Company's proposal as it is for the sustaining capital and controllable operating expense aspects.

Consistent with its overall finding, the Board is approving amounts only for the two test years of 2008 and 2009. The Board finds that the Applicant's plan for upgrading and modernizing its IT infrastructure and investment in its IT systems must take a long-view approach, must be balanced and must be consistent with the Utility's size and its organic growth as well as customer growth. The Board therefore orders that there will be a 10% increase per annum in the IT capital budget in the next two test years, as follows: 2008 - $23.0 Million and 2009 - $25.3 Million. With $23.0 Million in 2008, the Applicant will be in a position to commence the majority of its proposed projects, judiciously manage its program overall and maintain significant progress in this business area.

3.3 Meters

The Company's expenditures for metering fall into the following three categories:

- Wholesale meter installations;
- Smart meter installations to convert previously bulk-metered condominiums; and
- Smart meter installations to meet the Ontario Government's requirement.

The table below sets out the expenditures associated with each category for years 2008 and 2009.

Table 2
Metering CAPEX

		2008	2009
Conventional Metering[5]	Wholesale Meters	$9,564,000	$10,839,000
	Smart Meter conversion of bulk-metered Condominiums	$3,400,000	$5,700,000
	Total	**$12,964,000**	**$16,539,000**
Smart Metering[6]		**$36,207,000**	**$34,567,000**

Wholesale Metering

Wholesale meter installations are for the purpose of replacing meters previously installed and owned by Hydro One Networks. As the seal dates of the meters owned by Hydro One Networks expire, these meters are replaced by meters installed and owned by the distributor, in compliance with requirements of the IESO.

Board Findings

No party took issue with the Company's proposed expenditures in this category. This is an IESO mandatory meter replacement program, and there is no discretion to be exercised by Toronto Hydro. The Board finds the Company's forecasts of expenditures for 2008 and 2009 reasonable and approves them.

Smart Meters for Condominiums

The Company's proposed expenditures in this category relate to installing smart meters for condominiums, an alternative to smart sub-metering for which there are alternative providers. These smart meter conversions establish the condominium owners as customers of Toronto Hydro as the regulated monopoly distributor rather than as customers of an alternative smart sub-meter provider.

[5] Exhibit D1, Tab 8, Schedule 5, Table 1
[6] Exhibit D1, Tab 8, Schedule 5, Table 1 (updated)

Board Findings

On January 8, 2008, the Board issued a Notice of Proposal to amend the Distribution System Code and to issue a Smart Sub-Metering Code. While the Board has not yet formally adopted the change to the DSC and the new code, the Company's proposed involvement in this conversion initiative is consistent with the proposed section 5.1.9 of the DSC. The Board approves the Company's expenditure forecasts for this activity for purposes of setting rates for 2008 and 2009.

Board staff questioned whether sub-metering customers in condominiums who cause higher metering costs should be paying higher rates through a balancing contribution or through the creation a separate rate class, which would give effect to an allocation of costs appropriate to this category of customer. VECC on the other hand argued that as conversion is government driven the costs should be allocated to all customers.

It is true that there can be many elements of distribution costs that are not driven uniformly by sub groups of a given rate classification. At this time, for the purposes of this Decision, the Board will not consider differentiation in metering costs to be a pivotal consideration in entertaining the separation of the existing residential class or to direct the institution of contributions, capital or otherwise.

This is an issue that requires consideration in a more generic proceeding, with appropriate notice to effected parties, directed towards rate design, and cost allocation

Smart Meters Mandated by Government

Toronto Hydro is one of the named distributors that were authorized by Ontario Regulation 427/06 to implement the Government's objective of the installation of 800,000 smart meters by the end of 2007. The Company began installations in 2006 and has continued since then.

The Company proposed that, going forward (i.e. for the test years period and beyond), its investments in smart meters be considered part of its core business, and therefore form part of its rate base. As such, there would be no need for rate adders and deferral/variance accounts. The Company also sought to include in the rate base expenditures associated with the 2007 year.

Below the Board deals with these issues, as well as the regulatory treatment of the costs of the meters that are replaced by smart meters.

Smart Meter Capital Expenditures for 2008 and 2009

As noted, the Company estimated its capital expenditures for smart meters in this category at $36.2 Million for 2008 and $34.6 Million for 2009.

The Board determined[7] there were fourteen cost categories in relation to minimum functionality. These categories were set out in Appendix A to that Decision. The Board also stated that costs beyond minimum functionality can be recovered as part of distribution rates in an individual utility's next rate case, if supported, and named some of those categories of costs.

The Company provided a breakdown of the minimum and beyond minimum functionality categories[8]. The amounts for years 2007 to 2009 are shown in the table below

Table 3
Smart Meter Costs

	2007	2008	2009
Minimum Functionality	$33,178,000	$30,756,000	$30,112,000
Beyond Minimum Functionality	$10,491,000	$5,451,000	$4,455,000
Total		**$36,207,000**	**$34,567,000**

Board Findings

The Board notes that the parties did not challenge the budgeted amounts specifically; rather, their submissions dealt with the need to track these forecasts through variance accounts.

On the basis of the record adduced, the Board approves the proposed capital expenditures amounts; however, the Board does not approve the Company's proposed regulatory treatment associated with these investments. This matter is discussed below under "Regulatory Treatment of Smart Meters".

[7] *Combined Smart Meter Decision EB-2007-0063,* August 8, 2007
[8] Exhibit R1/Tab 1/Schedule 9.1 b)

Regulatory Treatment of Smart Meters

In the Combined Smart Meter Decision the Board approved the Company's Smart Meters expenditures for the calendar year 2006 that were in accordance with the legislated minimum functionality[9]. The Company was authorized in that Decision to incorporate these 2006 expenditures in rate base in a subsequent rate application.

In the Decision on a motion by Toronto Hydro to vary certain aspects of the Smart Meter Decision, made September 21, 2007 (EB-2007-0747), the Board approved Toronto Hydro's request for a rate rider, effective for the period November 1, 2007 to April 30, 2008, to clear the 2006 Smart Meter Deferral Account credit balance and to set a rate adder to fund the 2007 expenditures.

As previously noted, in this application the Company proposes that as of 2008, smart meters should be considered part of its core business and therefore should be included in rate base. As such, there would be no further need for rate adders and no need for deferral or variance accounts associated with smart meters. The Company also sought to include in rate base expenditures associated with the 2007 year; the variances recorded in smart meter capital expenditure variance account 1555; and smart meter operating expenses variance account 1556.

Board staff noted that, consistent with the Smart Meter Decision, the Company can incorporate the 2006 expenditures in rate base. Board Staff also noted that the 2007 expenditures have not been reviewed and approved by the Board. Board staff further noted that the Smart Meter Decision was silent on how future capital expenditures would be treated.

CCC, SEC and VECC noted the adjustments to the Company's forecasts of capital expenditures and the correction of errors relating to depreciation and argued that as the Company's ability to forecast accurately has not been established, it would be premature to include the smart meter expenditures in rate base. CCC argued that it is fundamentally important that shareholders and ratepayers be kept whole with respect to this government-led initiative. VECC argued that until the premature retirement and replacement of meters by smart meters is completed in 2010, smart meters are not a core utility function; they should be considered a government initiative and the costs

[9] The Board also approved investments for some interval meter conversions for GS>50 kW customers.

should be tracked and dealt with separately. SEC argued that there is considerable likelihood that actual expenditures will differ considerably from those forecast.

VECC argued that the appropriate treatment is to continue with variance accounts and rate riders. VECC disagreed with the clearance of any balances in the accounts until they have been subjected to a prudence review, at a minimum by Board staff. VECC argued that a prudence review is required for the beyond minimum functionality costs and therefore these should be tracked in a variance account, even if they are allowed in rate base. VECC also argued that the Company's forecast of expenditures for sub-metering is not reliable and that a variance account should be established to track the costs and revenues associated with sub-metering.

Board Findings

On the basis of the Board's findings in the Smart Meter Decision, the Board accepts that the capital expenditure on smart meters until the end of 2006 can be reflected in rate base. Those expenditures were previously reviewed and approved by the Board.

With respect to the 2007 expenditures, the Board notes that the Company had filed forecasts as part of its original application[10]. It updated that forecast on November 30, 2007, and subsequently provided the actual 2007 values[11] .

The 2007 values were broken down in the categories of minimum and beyond minimum functionality. The Board agrees with the Company that parties had opportunities to test the prudence of these expenditures. The Board has no basis to reject the 2007 expenditures on the strength of any argument by the parties. The Board finds that the Company's evidence in this regard is sufficient for the Board to accept the expenditures for 2007 as reasonable and include them in rate base.

Having said that, it is important to note that as the "beyond minimum functionality" expenditures for 2007 have not been subjected to a detailed review in this proceeding, our acceptance of them should not be considered to have any particular precedential value in the consideration of such expenditures by other utilities, or this utility, in a future rates proceeding. The Board further finds that the balances recorded in smart meter capital expenditures account 1555 be included in rate base; however, the balances

[10] Exhibit D1/Tab 8/Schedule 5
[11] Undertaking T5.1 (Confidential) and Exhibit T1/ Tab 5/ Schedule 1 (Confidential)

recorded in smart meter operating expenses account 1556 shall be expensed in the 2008 rate year.

While the Board has accepted the Company's capital expenditure forecasts related to smart meters for 2008 and 2009, the Board shares the concerns expressed by parties with respect to the Company's proposed regulatory treatment.

The forecast capital expenditures are quite large ($36.2 Million for 2008, $34.6 Million for 2009), and they are to take place over two test years. While the Board accepts that the Company is now in a better position to forecast its costs associated with smart meters, the Board is of the view that there is still considerable risk that the Company's forecasts may be substantially off the mark, resulting in significant over- or under-recovery. The issue is not necessarily that smart meter installation expenditures may not materialize; rather, the concern is the potential of timing differences in the actual expenditures from those forecasts. Timing differences will always exist, however, neither the Utility nor ratepayers should benefit or be burdened by an initiative that is temporal in nature and can be reasonably viewed as a cost pass-through. Treating smart meter expenditures for rate making purposes like any other core distribution activity is premature. The Board sees no harm in permitting the current regime to continue as it offers protection for both the Company and ratepayers from the vagaries of missed forecasts. As the installation program progresses and once the Board has reviewed and approved actual expenditures, bringing these expenditures into rate base can be considered again.

The Board therefore does not accept the Company's proposal to include the forecast capital expenditures in rate base for the 2008 and 2009 test years. The current regime where these expenditures are funded through a smart meter adder shall continue, as shall the variance accounts mechanisms currently in place to enable true-ups.

This leaves the issue of what should be the appropriate rate adder to fund the forecast expenditures. For certain other distributors who were not named by the government to implement an early smart meter program, upon application for enhanced funding, the Board has increased the adder to $1.00/per month per metered customer to recognise the pending ramping up of expenditures on smart meters for these distributors. The Applicant is a named distributor under government regulation and its rate adder of $0.68/month per metered customer was revised quite recently, in the fall of 2007. As shown in the table above, the Applicant's estimated spending on smart meters will continue at somewhat lower levels for 2008 and 2009. Therefore, the Board finds that the Applicant's current rate adder is reasonable and shall continue.

Regulatory Treatment of Stranded Meters

As smart meters are replacing existing meters, there are stranded costs. In the Smart Meter Decision, the Board determined that the stranded costs associated with existing meters should stay in rate base. The Company's revenue requirement in the current application reflects that treatment.

Alternative treatments were proposed, such as transferring the net book value to a deferral account and drawing down the balance over a certain time period or leaving it in rate base but depreciating these stranded assets quicker, depending on rate impacts. CCC encouraged the Board to develop a policy that would apply to all distributors

<u>Board Findings</u>

The Board does not have a policy with respect to the retirement of the stranded meters. The record in this proceeding has not produced sufficient evidence of the value of these assets in the 2008 and 2009 test years. If better information were made available, it would have assisted the Board in its assessment of the parties' recommendations. As such information is not available, the Board has decided the Smart Meter Decision shall apply in this case. Having said this, the Board notes that the bulk of the stranded assets will still be in rate base at the end of the 2009 test year. At that time, in the absence of any Board policy, the issue may be brought forward by any party as part of a future Toronto Hydro rates proceeding.

Regulatory Treatment of Vehicles for Personal Use

Board staff raised the issue whether the $200,000 for leased vehicles for executive personnel should be kept in rate base rather than expensed.

<u>Board Findings</u>

There is no generally accepted method whether costs associated with leased vehicles for executive personnel should be capitalized or expensed for ratemaking purposes, and the Board does not have a policy in this regard. The Board accepts the inclusion of these costs in rate base as reflected in the Company's application.

3.4 Proceeds from Sale of Assets

In its initial filing, the Company forecast that it would sell two work centres; 28 Underwriters Road in 2008 and 60 Eglinton West in 2010. The Company proposed to credit 50% of the forecast net after tax gain on these sales and reduced its revenue requirement for those years accordingly. The revenue requirement offset for 2008 was $0.4 Million, 50% of the anticipated net capital gain of $0.8 Million for selling 28 Underwriters Road.

During the hearing, evidence was given that two other work centre properties, 228 Wilson Ave. and 175 Goddard St., which were to be sold in 2007 at a total capital gain of $9.5 Million, may or may not be sold in 2007. The evidence also revealed that another six parcels of land within or around distribution stations used for purposes of storage or parking were considered by the Company to be surplus to its needs and were to be sold in 2007 (Mowat, Orfus, Bathurst, Birmingham, Sterling, Rustic). The anticipated capital gains from these six parcels of land were estimated at $2.3 Million. The Company initially resisted updating its revenue offset for the test years in the event the properties were not sold in 2007. However, at the end of the oral hearing, and in argument-in-chief, the Company proposed that in the event the surplus properties were not sold in 2007, 50% of the actual net after tax gain in a given year would be included as part of the revenue offset for the following rate year. In reply argument, the Company clarified that this proposed treatment would apply only to the four work centres. The Company noted that this proposed treatment eliminates the need to track the gain on sale in a variance account.

In addition, there was evidence that the Company had sold a property in 2006, the Belfield property, and the ratepayers had not shared any of the $1.5 Million capital gains realized from the sale.

Intervenors argued that the work centre properties are not truly surplus. As they are part of the Company's overall plan to consolidate and renew facilities, the ratepayers are entitled to 100% of the capital gains. With respect to the 2006 sale of the Belfield property, some parties argued for refunding the capital gain to customers.

Board Findings

At the time the Applicant's 2006 rates were set, there was no provision made for the ratemaking treatment of capital gains on sale of property. Also, there is no provision in any other Board-issued document which would have made it a requirement for the Applicant to bring forward any capital gains for disposition. To direct sharing of any capital gains in 2006 and 2007 would be out of period ratemaking.

Therefore, with respect to the Belfield property sold in 2006, the Board will not direct any sharing of the capital gains.

The Company's reply argument confirms that the 228 Wilson Ave. and 175 Goddard St. work centres were not sold in 2007. The Board agrees with intervenors that these two properties, as well as 28 Underwriters Road and 60 Eglinton West, have been rendered redundant and have been or will be sold as part of the Company's Facilities Consolidation and Renewal Plan (the "Plan"). If it were not for the Plan, the properties would continue to be used and useful. The properties' functions are useful and will be transferred to or replaced by other facilities, at a substantial cost to the ratepayer. The total capital cost of the Plan to 2011 is estimated at $105 Million[12]. The estimated capital cost of the Plan up to and including 2009 is $62.5 Million[13].

To defray these substantial costs to the ratepayer, the Board finds that 100% of the net after tax gains from the sale of 228 Wilson Avenue, 175 Goddard Street, and 28 Underwriters Road, the properties that are planned to be sold in 2008, should go to the ratepayer. The Company's revenue requirement for the 2008 test year shall be adjusted downward by $10.3 Million to reflect this finding. As the sale of 60 Eglinton West is planned for 2010, it does not impact the rates being set in this proceeding.

In making this finding the Board considered two of its recent Decisions. In a Decision which dealt with the sale of cushion gas by Union Gas Limited (the "Cushion Gas case), the Board allocated 100% of the capital gain to the utility[14]. The Board made that allocation after finding the evidence established the asset to be truly surplus in that the utility did not intend to replace it. In contrast, in Toronto Hydro's case, the evidence is clear that the properties' functions are not surplus and will be transferred to another location or replaced.

[12] Exhibit C2/Tab 2/Schedule 2/Page 11, Table 8
[13] Ibid
[14] EB-200-0211, Decision and Order, June 27, 2007.

The Cushion Gas case was based upon a prior decision of the Board which established that the Board had the jurisdiction to allocate proceeds from sales of capital property in the course of establishing just and reasonable rates (the “Capital Proceeds” case).[15] The Board considered both the Cushion Gas and Capital Proceeds case in arriving at its decision.

The Board further directs the Company to employ a variance account to record any differences in the gains reflected in rates and the actual gains achieved from the sale of these properties either in 2008 or beyond.

With respect to the parcels of land in or around the Company’s distribution stations, the Board understands that these properties are not linked to the Plan. For two parcels of land (Mowat, Orfus), the evidence is clear that these were sold in 2007. Consistent with its earlier finding, the Board will not direct any sharing of the capital gains associated with the Mowat and Orfus parcels of land.

For the remaining four parcels of land, the evidence is unclear whether all or any of these four were sold in 2007. The Board notes that Toronto Hydro’s proposed regulatory treatment of the capital gains did not include the capital gains associated with the sale of these four parcels of land. The Board directs the Company to also record in the above variance account 100% of the net capital gains associated with the sale of these four pieces of land; at the next rate hearing the Company will have an opportunity to make submissions regarding the appropriate allocation of these gains between the shareholder and ratepayers.

[15] EB-2005-0211/EB-2006-0081, Decision and Order, January 30, 2006.

4. Operating Revenues and Expenses

4.1 Load Forecast

The Applicant described in its application how the development of its revenue and load forecasts was a multi-step process involving the following elements:

- The total system-purchased energy forecast was developed based on multi-factor regression techniques that incorporated historical load, weather and economic data.
- A system demand forecast was determined based on the historical and forecast load factor relationships.
- Energy and demand by rate class were forecast based on historical billing statistics.
- A forecast of customers by rate class was determined using time-series econometric methodologies.
- Revenues were calculated by applying the proposed distribution rates to the rate class billing determinants for the forecast period.

In providing an overview of its methodology and model, the Applicant explained that a key element in its methodology is a multi-factor regression model that takes weather, economic output, load characteristics and calendar variables into consideration. The Applicant also explained the role that each of the variables played and its use of dummy variables to capture weather and other physical anomalies.

A forecast of customer numbers was based on the fairly flat customer base experienced in recent years, and an explanation was given regarding expected changes in customer numbers that would result from the Smart Meter program and the effects of Smart Sub-Metering. In its updated forecast of November 12, 2007, the Applicant noted that since tabling the original forecast, the provincial government's regulations related to smart metering in multi-unit buildings have been released and the assumptions regarding penetration of smart meters in condominium buildings had been revised accordingly.

The Applicant presented a comparison of the results from testing the various models it had developed for forecasting purposes. It was confirmed by the Applicant that, while the selected model was judged best overall based on model statistics and forecasting accuracy, a number of other models that had been rejected had actually produced more accurate ex post forecasts.

For the proposed 2007-2009 load forecast, the Applicant presented a table showing those situations where, in the judgement of the forecasters, adjustments were required. These manual adjustments lowered the forecast for each year.

The weather was represented in the multi-factor analyses by the number of Heating Degree Days ("HDD") and Cooling Degree Days ("CDD"); the economic output by the real Gross Domestic Product ("GDP"); load characteristics by the peak hours during the month; and the calendar variables by the days of the week, holidays and other seasonal variations.

The data available to, and used by, the Applicant reflected data from January, 1998 onward, coinciding with the amalgamation of the six former municipal utilities into the present Utility. The Applicant explained that this amount of data provided over 100 data points which its forecasters considered to be a reasonable data set.

Weather normalization was carried out as a part of the forecasting process. However, no details were provided respecting the conversion of actual load experienced in a particular year under specific weather conditions as compared to a standard or "typical" weather year.

The Applicant explained that the forecast for heating and cooling degree-day inputs is based on a ten-year historical average of HDD and CDD. A 10-year average was chosen over the more conventional 30-year average based on analysis of the annual HDD and CDD data. In an interrogatory response, the Applicant tabled values that permitted the trend to be determined using a 10-year average rather than the full 30-year average. No party contested this aspect of the Company's proposal.

While Board staff's submission concentrated on the methodology that the Applicant had employed and the possible effect this may have on the resulting load forecast, the intervenors generally concentrated on the forecasted load growth and recommended specific actions the Board should take in response to the Company's projection.

CCC noted that the November 12, 2007 updated forecast is approximately 0.9% lower than the original August 2, 2007 forecast and that the Applicant's rationale for the update was that more current information was available.

While CCC stated it did not take issue with the load forecast as it relates to setting rates for 2008 and agreed that the use of current information was appropriate, it pointed out that the Applicant could benefit from the updated forecast for as long as three years; that is, as long as the new rates, based on the updated information, were in effect. CCC pointed out that a reciprocal benefit was not available to the ratepayers, because while future load changes relative to the three-year forecast may be in ratepayers' favour, however, the opportunity to revisit the rates may not be afforded the ratepayers. CCC also submitted that the Board should examine the impacts of CDM in conjunction with the OPA and, on a going forward basis, should give electricity distributors explicit direction as to how to account for such impacts.

SEC noted that after originally forecasting a slight increase in load between 2007 and 2010, the Applicant was now projecting a decrease of 0.9% over the period. SEC pointed out that the forecasted negative growth from 2007 to 2010 contrasts with the historical annual load which showed an average annual growth rate in weather-normalized load of positive 0.6%. SEC also stated that the Applicant's forecast was not consistent with the evidence submitted by the OPA in support of the IPSP which predicted an increase in weather normalized energy of 1.2% between 2007 and 2010 for Ontario as a whole, and an annual growth rate of 1.4% for the Greater Toronto Area. SEC also noted that the OPA forecast, unlike that of the Applicant, has taken into consideration conservation potential as well as declining average uses and has come up with a load forecast that is considerably higher than the Applicant's. In SEC's view the Applicant's load forecast should be 0.6% above the 2007 level, or 26,788 GWh in aggregate.

VECC noted that during the hearing the Applicant was asked to comment on the differences between its forecast and that of the OPA which showed load growth in the range of 1.1% annually. VECC further submitted that it is critical that the Board provide direction to distributors regarding the treatment of the impact of CDM on the load forecast and the type of LRAM that will be approved. VECC adopted SEC's submission to the effect that the Company's Load Forecast is unreasonably low, and should be replaced with a forecast that provides for a 0.6% growth over 2007.

In reply, the Applicant reiterated that it stands behind its forecasts and in areas of its own activity takes full responsibility for them.

Board Findings

The importance of load forecasting in the rate setting process can scarcely be overstated, particularly for a multi-year application. The projected decrease in load for 2008 and 2009 places direct upward pressure on the burden placed upon the Applicant's customers through an increase in distribution rates. The forecast of decreasing load advanced by the Applicant runs counter to a general trend of continuously increasing load over the last considerable number of years, as well as the forecast adopted by OPA for its system planning purposes. The OPA forecast suggests a small increase in load for the Greater Toronto Area over the next few years.

It is perhaps surprising that given the importance of load forecasting, there is not yet a single prescriptive methodology adopted by all of those obliged to develop forecasts, or even a general governing consensus on the process, including the treatment of influencing factors like CDM. It is clear that there is not.

Some intervenors objected to the November 12, 2007 update to the forecast on the grounds that it represented a selective tweaking of one element of the forecast and the application, while other interim adjustments that might have been made, which may have lowered the revenue deficiency, were not also advanced for consideration.

While the Board is generally concerned with selective adjustments to evidence made in the midstream of an application, it finds no fault with the Applicant's approach in this aspect of this case. The November adjustments were designed to reflect specific regulatory changes which had a measurable effect on the forecast. These adjustments needed to be reflected in the forecast.

The disparity between the Applicant's forecast and the OPA's forecast is more noteworthy. The OPA has a critical statutory role to play in the development of short, medium and long term plans for the electricity sector in the province. The OPA is also central to the development, funding and implementation of CDM programs. Key drivers in its plans are the respective load forecasts for the various regions of the province. While the OPA forecasting exercise may necessarily differ in important respects from the forecasting undertaken by individual utilities, there needs to be a good understanding among all of those affected by the OPA plans about how these forecasts are generated and calibrated, and how their respective forecasts may be informed by, or may depart from them.

The system administrator, IESO, also produces important forecasts, according to its own methodology, and for its own purposes.

One key aspect of inconsistent practices involves the extent to which, and the manner in which, CDM activities are reflected in the respective forecasts. In a number of utility applications for rates in 2008, the specific effect of CDM activities on throughput has been impossible to quantify with any reasonable degree of accuracy. This means that an important area of public policy, supported by considerable funding through distribution delivery rates, as well as through direct OPA program funding under the global adjustment, is not measurable according to a consistent and well understood methodology. This lack of alignment between the OPA forecasts and those generated by individual utilities also has implications for LRAM and SSM claims and calculations. LRAM and SSM claims are limited to the demonstrable effects of the specific utility's CDM programs on its throughput and revenue. In order to make this assessment, such effects must be empirically accounted for. The effects of CDM activities that are not attributable to the specific utility's actions must also be definitively accounted for.

The Applicant is not in any degree responsible for this deficiency, which is system-wide, and there is no suggestion that either the Applicant's or the OPA's load forecasts are in any way defective. They are simply inconsistent and this may be the result of the sector's still early years of its new institutional framework.

The Board accepts the forecast advanced by the Applicant, as amended throughout the process. This provides for a very small increase in load in 2008 of 0.03% and a small decrease in 2009 of 0.06% over 2006

Going forward, the Board encourages the Applicant to work with OPA, IESO, and perhaps others to understand differences in methodology employed by each. Of special interest is the development of methodology to account for the specific effects of CDM activities in forecasts. The success of LRAM and SSM applications is dependent on fully developed evidence respecting the effects of CDM activities on throughput. The Applicant can make a very important contribution to the sector by working with stakeholders to bring needed clarity to this aspect of forecasting and utility operations.

4.2 OM&A and General Expenses

The Applicant's proposed distribution expenses are shown in the Table 4 Distribution Expense Summary.

Table 4
Distribution Expense Summary16
($ Million)

	2006 Approved	2006 Historical	2007 Bridge	2008 Test	2009 Test
Operation	$ 41.2	$ 45.7	$ 50.9	$ 59.6	$ 65.4
Maintenance	$ 24.1	$ 36.8	$ 40.8	$ 46.5	$ 48.8
Billing and Collection	$ 26.1	$ 26.4	$ 26.3	$ 32.4	$ 32.8
Community Relations (Excl. CDM)	$ 2.9	$ 3.8	$ 3.3	$ 3.6	$ 3.7
Community Relations (CDM)	$ -	$ 13.1	$ 3.6	$ 1.5	$ 1.6
Administrative and General	$ 48.3	$ 25.4	$ 30.1	$ 35.1	$ 36.2
Subtotal	**$ 142.6**	**$ 151.2**	**$ 155.0**	**$ 178.7**	**$ 188.5**
Other Distribution Expenses	$ 19.2	$ 18.2	$ 16.6	$ 17.3	$ 18.1
Subtotal	**$ 161.8**	**$ 169.4**	**$ 171.6**	**$ 196.0**	**$ 206.6**
Amortization Expense	$ 126.9	$ 124.6	$ 132.4	$ 153.7	$ 160.9
Total Distribution Expense	**$ 288.7**	**$ 294.0**	**$ 304.0**	**$ 349.7**	**$ 367.5**

For the expense areas of Operation, Maintenance, Billing and Collection, Community Relations and Administrative and General Expenses which are reflected in the first subtotal in the above table and are described hereafter as controllable expenses, the Applicant is proposing to recover amounts of $178.7 Million in 2008, and $188.5 Million in 2009. When these numbers are adjusted to remove expenses attributable to Conservation and Demand Management activities, which form a discrete element of expense subject to distinct considerations, there is a 28.3% increase in the 2008 test year relative to the 2006 historical level. (2006 Historical: $151.2-$13.1=$138.1 versus 2008 Test $178.7-$1.5=$177.2.)

In its Argument-in-Chief, the Applicant stated that its revenue requirement included expenses of $185.8 Million, $195.8 Million and $202.9 Million for 2008, 2009 and 2010 respectively. This update was one of numerous evidentiary changes effected during the

[16] Exhibit D1/Tab 3/Schedule 1

course of the proceeding. These numbers are apparently revisions of the numbers in the above table, but they do not change the overall thrust of the application, which is that the Applicant is seeking a very substantial increase in its controllable expense levels relative to historical levels.

Parties to the proceeding and Board staff expressed concern about the overall level of increases contained in this application, including the increases sought in the controllable expenses for each of the years.

CCC stated that, in approving the budgets, the Board must be convinced that the budgets are reasonable, reliable and sustainable and argued that the Applicant has not presented a sufficient case for the Board to approve the proposed expenses.

In its written submission, SEC asserted that:

> "…these large overall budget increases result from a series of budget assumptions made by the Company to the effect that certain cost pressures will materialize during the test year. As in any budget-setting exercise, the Applicant would necessarily have had to make some assumptions about the probability of certain events occurring and driving up costs. Whether or not each of these assumptions appear reasonable when looked at in isolation from the overall number, SEC believes that the breadth and extent of the overall increase should serve as a "sanity check" on the budget assumptions.
>
> That is, the Board should ask itself whether all of the cost pressures in every department will materialize in a single year, or whether it's more likely that some of the cost pressures will materialize and some will not, and some will but not at the level predicted by the Applicant.[17]"

Board Findings

The table below reflects the level of spending over the recent past. This table includes evidence from the Applicant's previous rate application (RP-2005-0020/EB-2005-0421).

[17] Final Argument of the School Energy Coalition, para 1.1.3 and 1.1.4

Table 5
Expense Spending 2002 – 2005

Year	OPEX $000	% CHG	Total Dist Exp $000	% CHG
2002	159,800		281,800	
2003	159,200	(0.4)	276,800	(1.8)
2004	164,800	3.5	287,300	3.8
2005	167,139	1.4	292,127	1.7

As noted earlier, the applied for increases amount to over 28% as between the 2006 historical level and the 2008 proposed revenue requirement. The increases sought are not only sharp as between the 2006 historical year and the test years, but are also well in excess of spending levels over the recent past.

In other recent decisions the Board has observed that significant variances between historical spending levels and proposed spending levels require compelling explanation. For example, the Board's Decision in Barrie[18] said:

> "The increase from 2006 of 18.6% is not reasonable in the Board's view. Such a level of increase would only be justified with compelling evidence for the increase. Variance analysis forms a critical component of a rates application. It provides the explanation for changes in cost between Board approved and actual for the historical year and the explanation for year over year changes between all years. This analysis must include the level of the change experienced and the company's reasons for why the change is justified. The level or detail for the explanation should be proportionate to the amount in question. Ideally, these explanations should be included in the application. Alternatively, these explanations can be further explored through interrogatories. It is inappropriate to introduce new evidence through reply argument."

In another case, the Board stated that support for variances requires a level of proof commensurate with the extent of the variances sought.[19]

[18] Barrie Hydro Distribution Inc. EB-2007-0746

In other words, an applicant must present a case that demonstrates that the extraordinary increases sought are fully justified and compelling to the full extent of the increase sought.

The Board also is concerned about so-called “lumpy” changes in spending levels. Except in compelling circumstances, Utility spending should be managed so as to be reasonably level, with highs and lows lying within a fairly narrow range of change. To the extent possible, ratepayers should not be exposed to volatile changes in their delivery rates. Over the years the Board has adopted numerous measures designed to avoid this phenomenon, which can place special strains on institutional consumers with fixed budgets, or residential consumers on fixed incomes. While the overall bill impact of the Applicant’s proposal will not be as large in percentage terms as the claim in relation to previous year’s spending, it still must be assessed in accordance with the principles outlined here. Lumpiness may, to some extent, occur with a smaller utility, for which significant expenditures, particularly capital, may occur on a relatively infrequent basis, but a larger distributor of the size of the Applicant should be able to largely avoid “lumpy” expenditures.

The removal of the Regulatory Asset rate rider, pursuant to Board Decision RP-2004-0117 / RP-2004-0118 / RP-2004-0100 / RP-2004-0069 / RP-2004-0064 will have the effect of blunting the effect of any increases in delivery rates arising from this application, however, this effect is somewhat artificial in that ratepayers have a reasonable expectation that the termination of the regulatory asset recovery should result in a direct reduction in their overall charges.

Such proposed increases also raise concerns about the Utility’s ability to take into account systemic issues within its controllable spending envelope. For example, it is expected that demographic changes will be anticipated and addressed over a period as closely equivalent to the period giving rise to the problem, and handled within the normal range of spending variations from year to year.

Past underspending cannot be explained by inadequacy of returns by the Utility. The evidence shows that the Company has enjoyed rates of return in the recent past that exceeded the allowed rate of return on equity by one full percentage point on average over the period 2002 through 2006 inclusive. In that same period the Company paid to its shareholder an average of $43.3 Million per year by way of dividends.

[19] Hydro One Networks Inc. EB-2006-0501

For each of the areas below, the Board has examined the Company's claim in a manner that positions the budget within historical norms, while providing adjustments where the evidence supports them. In the end, the Board has approved a spending envelope to cover all aspects of controllable spending for 2008 and 2009. In other words, the Board does not approve or disapprove any specific line item within the Company's claim. The Company can apply the funds provided in the envelope where it determines it ought to. The Board does not seek to micro-manage the Company's business, only to approve a controllable expenses budget that is fully supported by the evidence, including the evidence of historical spending norms.

For 2008, the Board approves for ratemaking purposes the amount of $180 Million for controllable expenses. This amount compares to $161.3 Million in 2006 actuals, before the deduction of CDM amounts appearing in the updated table, which was provided in the Argument-in-Chief. This is an increase over the 2006 historical year actuals of 11.6%. For 2009, the approved amount is $185 Million, an increase of approximately 14.7% over the 2006 historical year actuals.

For additional clarity, except in the case of the Board's disallowance of the proposed expense related to the IESO's future fees discussed below, the Board's conclusions or comments on these matters are not additional reductions from the envelope amounts to be used for ratemaking purposes. Similarly, the Board's disallowance later in this Decision of the costs associated with the Peaksaver CDM program is also outside the spending envelope.

Affiliate Costs and Charges: Corporate Restructuring Initiative - Cost Allocation Study

The Applicant and THC reorganized business units to better reflect the purpose of their work (corporate or utility) and developed a new time-based shared service cost allocation methodology (the "new allocation methodology") in response to the Board's Direction provided in its earlier rate case:

> "The Board directs the Applicant to develop a time based shared service allocation methodology for non-direct corporate costs that incorporate the following elements:
>
> - Time/cost tracking for individual staff efforts
> - Description of the Applicant's need for the service

> - Assessment protocol and allocation of non-time related expenses.
>
> A detailed report on the shared service allocation rationale and methodology is to form part of the Applicant's next rate application. This process is to augment the existing shared service agreements and is in no way intended to diminish or replace the Applicant's existing arrangements."[20]

In response to that direction, the Applicant developed a cost allocation methodology internally. Singer & Watts, an expert hired by the Applicant to review various cost allocation methodologies and regulatory decisions on those methodologies, advised: "…because Toronto Hydro is relying on an internally developed cost allocation method, an independent review of the proposed methodology and its application is essential if the cost allocation is to be accepted during regulatory review"[21]. The Applicant retained R.J. Rudden Associates to perform an independent review of the cost allocation methodology; these consultants produced a study titled *Review of Shared Services Cost Allocation Methodology* (the "Rudden study") which was filed as evidence in this proceeding[22].

In addition to the development of a cost allocation methodology, the Applicant advised it had undertaken a full review of its affiliate transactions transfer pricing policy to determine if it was in compliance with the *Affiliate Relationships Code for Electricity Distributors and Transmitters* November 24, 2003 ("ARC"). The Applicant was of the view, and the Rudden study agreed, there was compliance with the ARC[23].

The ARC, in Section 2.3, requires that when a utility provides a service, resource or product to an affiliate, the utility shall ensure that the sale price is no less than the fair market value (FMV) of the service resource or product; and in purchasing a service from an affiliate, the utility shall pay no more than FMV. The ARC further states that for this purpose, a valid tendering process shall be considered to be definitive evidence of FMV. Finally, the ARC requires that where FMV is not discernable, a utility shall charge no less than a cost-based price to an affiliate for services, resources or products provided to that affiliate and shall pay no more than a cost-based price to an affiliate for services,

[20] EB-2005-0421 Decision with Reasons, April 12, 2006, ("2006 Decision") paragraphs 3.2.12-3.2.13
[21] Singer & Watt, *Report on Affiliate Transactions Regulatory Compliance Methodology and Implementation,* June, 2007, Ex. Q1, Tab 1, Sch. 1, page 59.
[22] R.J. Rudden Associates, *Report to Toronto Hydro Electric System Limited Regarding Review of Shared Services Cost Allocation Methodology,* June 30, 2007, Ex. Q1, Tab 4, Sch. 1 (the "Rudden study").
[23] Rudden study, page 5.

resources or products provided by the affiliate, with a cost-based price reflecting the costs of producing the service or product, including a return on invested capital.

Earlier this year the Board issued a document titled “Proposed Amendments to the Affiliate Relationships Code for Electricity Distributors and Transmitters” (the “ARC Report”).

The Applicant asserted that its practices were entirely consistent with the proposed changes to ARC embodied in that proposal. The Applicant further noted that with respect to transfer pricing for shared corporate services, the Board proposes that Section 2.3 of the ARC be amended “to expressly allow the use of cost-based pricing for shared corporate services” and that the Board had further indicated that “these proposed amendments accept that cost-based pricing will always be appropriate in relation to shared corporate services.” (See page 19 of the ARC Report).

The Rudden study noted that the Applicant methodology includes a review for compliance with the Board’s three-prong test as stated in EBRO 493/494. The components of the three-prong test are as outlined below.

- **Cost incurrence** which addresses the question as to whether or not the services for which costs are being charged are actually provided to the recipient and as to whether they needed by the recipient;
- **Cost allocation** addressing the question as to whether or not the costs for the services were appropriately allocated to the recipients; and
- **Cost/Benefit** addressing the question as to whether or not the benefit received equalled or exceeded the cost.

The Rudden study appeared to express reservations about the Applicant’s compliance with two of these three tests. Specifically, where cost allocation was concerned, the Rudden study stated that:

> "Subject to appropriate development of FMVs and appropriate application of the FMVs in determining transfer prices …, both of which the Applicant management informs us will be completed in the future, the THESL methodology meets the Cost Allocation test."[24]

During cross-examination by Board counsel, the Applicant's witness stated that contrary to the representations recorded in the Rudden study, the Applicant had decided not to develop or use FMV in pricing inter-corporate services transactions, and that all services were cost based.[25]

With respect to the cost/benefit test, the Rudden study noted:

> "In developing the Shared Service Inventory, each transaction was reviewed for compliance with the cost/benefit test of the OEB's three-prong test. However, the THESL Report does not provide an explanation of how the cost/benefit review was conducted, and there does not appear to be documentation for the information relied on or judgements reached in performing the analysis."
>
> Recommendation 1: The THESL Report should include an explanation of how the cost/benefit review of the OEB's three prong test was conducted and should document the information relied on and judgments reached in performing the analysis.[26]

The Applicant's management declined to follow that recommendation, and stated that "a sufficient review was performed on the cost benefit portion of the OEB's three pronged test and no further documentation is required".[27] Under cross-examination the Applicant's witness confirmed the Applicant's view that there was no need to do a full cost benefit analysis.[28]

VECC was the only intervenor to make a detailed submission in the area of shared services. SEC and CCC stated in their submissions that they supported VECC's position on this issue.

[24] Rudden study, page 11.
[25] Transcript Volume 3, page 17, ls. 3-5; page 18-19, ls. 28-2
[26] Rudden study, pages 11-12.
[27] Rudden study, page 5.
[28] Transcript Volume 3, p. 22, ls. 5-7.

In its submission, VECC stated that the Applicant cost allocation methodology, as reviewed by R.J. Rudden, does not meet the previous panel’s direction as the new Shared Services methodology was not finalized and the specific service schedules, as required by the ARC, were not available for Rudden to review relative to the Board’s three prong test. VECC stated that this was of concern since, in its view, without disaggregated analysis of specific services at a sufficient level of detail by an independent third party, neither the Board nor the Applicant ratepayers can be reasonably certain that the Applicant is not paying too much for inbound services from the parent company Toronto Hydro Corporation (“THC”) and is not undercharging THC and affiliates for outbound services.

VECC also suggested there was a lack of evidence respecting the FMV for inbound services available in the marketplace; and that it was not clear from the evidence that the Applicant had used a fully allocated cost model, including a return on capital, in its cost-based transfer pricing on outbound services to related companies.

VECC argued that the Board has been placed in a difficult position since in its view the Applicant had not fully complied with the Board’s direction in EB-2005-0421. VECC stated that the Board could not approve the Applicant shared services methodology because of its flaws, which result in incomplete compliance with the ARC, and more importantly, in VECC’s view, the costs and revenues claimed for inbound and outbound services may not be reasonable.

VECC took the position that the Board must set an example and require the Applicant to prepare a full set of service-specific schedules that comply with the ARC requirements and then assess each inbound service using the three prong test and in particular cost/benefit including FMV. Where outbound services are concerned, VECC argued that specific service schedules are required and the Applicant should ensure that time based allocations, using fully allocated costs, are the basis of the transfer price, subject to cost being at FMV.

Furthermore, VECC stated that the Board should require R. J. Rudden Associates to be retained by the Applicant at shareholder expense to review the Applicant’s results and file its report with the Board.

VECC also took the position that with respect to the Applicant’s request for a multi-year rate order, the insufficiency of the Applicant’s ARC compliance with respect to shared services requires that the Board should refuse to approve the applied for shared services costs/revenues beyond 2008, and then consider such costs for approval only with the proviso that the Applicant come back with an appropriate report. VECC concluded that approval of shared service expenses/revenues for years beyond 2008 would be informed, whether under cost of service or IRM, by the review they proposed to be filed with the Compliance Branch of the Board.

Board Findings

The Board accepts that, with the limitations noted above, the Rudden study generally supports the affiliate relationship practices of the Applicant, and approves the applied for shared services costs/revenues for 2008 and 2009.

The Board notes the deficiencies in the Rudden study, and directs that the Applicant file a complete and updated Rudden study at the Company's application dealing with rates beyond the test period dealt with in this proceeding. The updated Rudden study should review the allocation methodology currently used by the Company, and the shared services agreements based upon that methodology, and provide an opinion on their conformity with the Board's requirements.

As noted earlier, the Applicant declined to provide R. J. Rudden Associates with an explanation of how the cost/benefit review of the OEB's three prong test was conducted and to document the information relied on and judgments reached in performing the analysis.

To ensure the completeness of the updated Rudden study, the Board expects the Applicant to ensure that all information is provided as requested.

The Board also notes that, because of time constraints, in concluding that the allocation methodology met the cost allocation test the Rudden study relied upon a representation by the Applicant that appropriate development of FMVs and appropriate application of the FMVs in determining transfer prices would be done. After the Rudden study was completed, the Applicant decided not to proceed with development and application of FMVs.

Given the amount of time available to complete the updated Rudden study, the Board expects that these deficiencies will be addressed.

Affiliate Costs and Charges: Costs of Corporate Reorganization

The Applicant's evidence indicated that since the last Applicant's rates case, 210 employees have been transferred from THC to the Applicant. The purpose of this reorganization was to remove distribution service providers from the parent corporation and reunite them with the distribution business.

The Applicant's evidence was that the net effect of the reorganization is a decrease, from $51 Million to $7 Million in the quantum of annual shared services acquired by the Applicant from affiliates.

This was the subject of much cross examination during the hearing. The Applicant demonstrated that the 2006 Shared Services Cost from THC on a pre-reorganization basis was $51,246,009. The 2007 shared service cost from THC under the new allocation methodology was $6,976,836. The exhibit also includes the 2007 Applicant cost of $48,304,148 related to the additional costs now incurred by the Applicant as a result of the reorganization. When these costs are added to the remaining THC costs, the total 2007 cost is $55,280,984, representing an increase over the 2006 pre-reorganization cost of $4,034,975 or 7.9%.

The impact of the old versus the new allocation methodology was also reviewed. In its Argument-in-Chief, the Applicant states: "…the difference between the new and old methodologies means that services acquired by the Applicant from affiliates will be reduced by $2.4 Million in 2008"[29]. The Applicant further states in its Argument-in-Chief that it forecasts that, under the new methodology, "the total dollar value of all shared services it will acquire will only marginally increase (1.9%) over the 2008, 2009 and 2010 period, which is below the Applicant's forecast rate of inflation."[30]

VECC stated that it was clear from Exhibit T1 Tab 3 Schedule 1 that the result of the Toronto Hydro Corporation - Toronto Hydro-Electric Service Limited reorganization has not resulted in a cost reduction, or even a zero sum gain. VECC noted the net $4 Million increase in costs from 2006 and submitted that the reorganization and shared services model combine to move the Applicant to higher affiliate transaction costs with no commensurate increase in services required by the utility to serve its ratepayers.

[29] Argument-in-Chief p. 18, Para. 49
[30] ibid

Accordingly, VECC submitted that the Board should specifically reduce the 2008-2010 O&M expenses by $4 Million to keep ratepayers in a neutral cost position. VECC stated that its proposal was consistent with the Board's 2006 Decision on corporate costs for Enbridge Gas Distribution ("EGD"), where the Board found that EGD had not fully justified its claim and reduced the claimed costs of specific services by up to 50%.

VECC also expressed concerns about the Applicant's Corporate Governance Centre costs. VECC submitted that the Board, as a result of the inadequacy of the shared services review, cannot properly determine how much overlap and duplication exists within the total governance costs incurred by the Applicant and THC, or whether aspects of governance allocated to the Applicant is properly a shared service at all.

Accordingly, VECC submitted that the total governance costs should be reduced by $5 Million and that the Applicant should be directed to provide appropriate evidence supporting its governance costs, both internal and external, and have that evidence reviewed by an external expert at the cost of the Applicant. VECC added that such a review would be a component of the shared services review requested previously in its submission. Finally, VECC submitted that, specific to the issue of governance costs, it is important that these costs be benchmarked against comparator utilities.

Board Findings

The additional expense that appears to be now associated with the shared services is concerning. The disparity in costs between the old and the new allocation methodology of approximately $4 Million leaves the Board with doubt with respect to the appropriateness of the costs then or now. This area of the evidence was subject to serial updates, and there can be little confidence that the overall effect of the reorganization has been definitively captured in the evidence of this Application.

The Board will not order a specific reduction attributable to this aspect of the Applicant's rate proposal; however this budget will have to be managed by the Company within the overall reduction in the operating expenses category.

The same is true with respect to the Corporate Governance Centre. This cost centre appears to capture costs related to the strategic direction of the Company originating with the Board of Directors and the CEO's office, but also contains a variety of issues that appear to be, at best, only tangentially related to these activities. The Company is responsible to ensure that dollars dedicated to these functions procure appropriate value and productivity for ratepayers.

There is no value in having the Board micro-manage or direct spending in these areas. The Company is accountable for these decisions within the overall envelope of approved spending.

Workforce Renewal and Compensation

Workforce Renewal

The Applicant provided evidence that it is faced with a need to renew its workforce in the face of retirements that will occur at an increasing rate over the next five years. The Applicant stated that while it was not unique in facing this impending demographic shift, its situation was unique because of the time it takes to train employees to work on its complex and varied distribution system. Accordingly, the Applicant stated that it planned to hire 150 apprentices between 2008 and 2010, and that if it did not immediately begin to address future retirements, it would not have adequate time to recruit and train new workers before current workers begin to retire in large numbers.

SEC stated that the Applicant is proposing a specific budget item to have employees work alongside other employees in order to address the issue of an aging workforce. In SEC's view this is an item that other companies, and other utilities, manage within normal operating budgets and without specific line items. This view is also shared by CCC who questioned whether this workforce renewal issue is unique to the Applicant or whether this is a problem that other entities are facing and addressing through normal budget constraints.

SEC, VECC and CCC all noted that of the 75 new hires projected for 2007 only 41 had been hired by December 6, 2007, which has led to an overstatement of the staffing cost budget for 2008. VECC questioned the reliability of the Applicant's long range staffing plan for three forward test years, citing the example of new hires forecast which differed from the actual hires by 182%. SEC further noted that it is not clear to what extent the cost of these new hires will be offset by retiring employees.

CCC and VECC submitted that the Applicant has not provided sufficient evidence, such as an employee survey or actuarial data from OMERS, to support its projection that 120 retirements will occur between 2007 and 2012.

CCC indicated that it was prepared to accept the Workforce Renewal (WFR) program costs for the 2008 test year, but not the amounts beyond 2008 due to the questionable reliability of the forecasts. CCC proposed that the Applicant should be required to come forward in its next rate proceeding with a long range staffing plan supported by more comprehensive evidence on retirements and a full cost-benefit analysis which supports its expenditures going forward.

In SEC's view, an incremental budget amount for the on-the-job component of the WFR is not justified. However, SEC agreed that the costs associated with the in-classroom portion of the WFR are reasonable. SEC submitted that the Applicant should be exploring cost-sharing arrangements with other utilities and partnerships with community colleges and other educational institutions that have classroom training in practical subjects as their core business.

VECC indicated that while it agrees with the need for a WFR in principle, it did not believe the Applicant has adequately addressed the completion/retention rate for the new apprentices and the retirement profile of the existing workforce. As such, VECC argued that the Board cannot approve the WFR program, or at least not accept its cost consequences as filed, particularly for three years. VECC suggested that specific requirements be placed on the Applicant to report to the Board on the status and costs consequences of the WFR and to indicate what remedial steps it will take to bring costs in line with approved budgets. VECC noted that this approach provides adequate protection for ratepayers.

Board Findings

The Company's Workforce Renewal program represents an important component of its rate proposal, both in terms of its impact on 2008 and 2009 rates and its ongoing impact on future costs. It is the kind of proposal that requires clear and reliable evidentiary support.

The Company's proposal addresses the issues raised by a demographic environment where the pace of projected retirements in skilled classifications can create labour shortages. The Company's proposal is rooted in projections of expected retirements and hirings over the next several years. The hiring of apprentices is meant to match and offset the projected retirements.

The program began in 2007, with projected hiring of 75 apprentices in that year. In fact, it appears that only 41 apprentices were hired in 2007.

This issue has surfaced in other recent Board proceedings, and describes a phenomenon that challenges all elements of the economy in varying degrees. It is a phenomenon of particular interest to industries where it is necessary to replace highly skilled workers on a schedule that corresponds to expected retirements.

The Board's consideration of the Applicant's proposal involves a number of factors. First, there is little doubt that the demographics require a planned response and that this is an issue that must be managed by the Utility.

Second, as alluded to earlier in this section of the Decision, this is a phenomenon that is not unexpected. It has taken years to evolve, and it has been "on the radar" for some time.

The evidence in support of the proposal consists of a series of forecasts respecting retirements, hiring rates, and retention of new hire rates. As noted, the forecast of new hires for 2007 proved to be materially overstated. In the Board's view, this is telling. The failure to meet the 2007 hiring objective may be due to a variety of factors, including a general shortage of apprenticeship candidates, and other factors both within and outside of the Company's control; however, the failure to meet this milestone casts doubt on the consequential 2008 figures, and by reasonable extrapolation on the figures advanced in support of the proposal for 2009.

Of equal concern are the projections related to retirements. While factors may be in place which favour the retirement of workers at given points within their pension entitlement structures, they do not necessarily translate into actual retirements. The fact is that the Company cannot compel the retirement of any of its employees at any given point in time. The Company's proposal attempts to balance its new hire forecasts and its retirement forecasts, with a high degree of interdependence. Doubt respecting any aspect of the forecasts leads to doubt about the details of the Company's proposal as a whole.

In assessing the Workforce Renewal plan within an overall consideration of the Company's compensation claim, the Board notes that there has not been a very precise calibration of the effect of the retirement of more experienced and more highly paid workers, and their replacement by younger, lower paid workers on a year by year basis. The Company's proposal is predicated on the realization of its projected replacements, but does not account for erosions in any aspect of the program, which the 2007 experience suggests will occur.

Having said that, the Board considers the Workforce Renewal plan to be in general directionally appropriate, and capable of achieving the kind of transition needed over time.

Compensation

The Applicant stated that its compensation is appropriately competitive, except for senior management where it is below comparable companies. As required by the Board[31], and in support of its position, the Applicant filed a study undertaken by Mercer Human Resources Consulting dated May 31, 2007, entitled "Compensation and Benefits Competitiveness" ("the Mercer report")[32] the Applicant stated that this compensation study covered the entire range of positions including unionized employees, administrative personnel, professionals, managers and executives.

Mercer was not asked to review the effectiveness of the Applicant's performance-based compensation philosophy, but nevertheless Mercer found the programs to be consistent with market best practice.[33] Mercer did not review the Applicant's forecast compensation levels, but the Applicant indicates that it relied upon Mercer forecasts for some of the assumptions made in its own compensation forecasts.[34]

Mercer's conclusion was that the Applicant's current compensation profile was appropriately competitive with the market, except for senior executives whose compensation was below market.

---

[31] 2006 Decision, paragraph 3.1.14: "The Board therefore directs the utility to file the independent compensation study that is currently under way prior to the next rate case. This study should include benchmarks with other North American utilities of similar size."
[32] Mercer Human Resource Consulting, *Compensation and Benefits Competitiveness Toronto Hydro Corporation*, May 31, 2007, Exhibit C2/Tab 1/Schedule. 3.
[33] Mercer report, page 1.
[34] Transcript Volume 3, page 58, ls. 6-28.

The Mercer report relied upon compensation information provided by the Hay Group. When examining executive compensation levels, Mercer did not do a comparison using utilities only. The Applicant gave evidence that it was difficult to find organizations comparable to the Applicant in size, so Mercer used a revenue cut to select 170 public and private sector organizations from a Hay Group database with which to compare the Applicant's executive compensation levels.[35] Included in those companies were some utilities. It was the Applicant's view that the comparison met the 2006 Decisions' directive that the study should include benchmarks with other North American utilities of a similar size.

The Applicant concluded that the Board should be confident that its executives and managers are generally compensated in line with comparable companies and that their compensation is appropriately structured to drive performance improvements.

The effect of the WFR and proposed compensation levels result in the increases in employee costs, detailed in the tables below:

Table 6
Toronto Hydro Total Compensation ($)

	2006 Historical	2007 Bridge	2008 Test	Variance 2008/2006
Executives	$1,718,844	$2,966,093	$3,359,458	$1,640,614
Managerial	$3,813,150	$6,968,573	$8,736,636	$4,923,486
Management/Non-Union	$17,053,273	$36,350,671	$39,777,741	$22,724,468
Unionized	$115,407,520	$130,170,375	$138,459,344	$23,051,824
Total	**$137,992,787**	**$176,455,712**	**$190,333,179**	**$52,340,392**

[35] Ibid., page 62, ls. 9-11, 20-28; page 63, ls. 1-5.

Table 7
Compensation for 2006

	# of Employees	Average Compensation	2006 Historical
Executives	6	$286,474	$1,718,844
Managerial	21	$181,579	$3,813,150
Management/Non-Union	137	$124,476	$17,053,273
Unionized	1187	$97,226	$115,407,520
Total			**$137,992,787**

Table 8
Compensation for 2007

	# of Employees	Average Compensation	2007 Bridge
Executives	10	$296,609	$2,966,093
Managerial	41	$169,965	$6,968,573
Management/Non-Union	291	$124,916	$36,350,671
Unionized	1265	$102,901	$130,170,375
Total			**$176,455,712**

Table 9
Compensation for 2008

	# of Employees	Average Compensation	2008 Test
Executives	10	$335,946	$3,359,458
Managerial	47	$185,886	$8,736,636
Management/Non-Union	294	$135,298	$39,777,741
Unionized	1312	$105,533	$138,459,344
Total			**$190,333,179**

VECC took the view that the increases in compensation costs from the Board Approved 2006 amount to the 2008 test year "are way above reasonable bounds, even taking into account the Workforce Renewal initiative." VECC argued that the transfer of 210 positions from THC, as part of the corporate restructuring, has increased the Applicant's net compensation and operating costs, without an offsetting equivalent reduction in corporate cost allocations. VECC noted that for unionized employees, total compensation continues to rise from 2008 to 2010, which is counterintuitive to the net change in head count, apprentices hired versus retiring staff, and the relatively lower average compensation of new hires. VECC further submitted that the forecasts of total compensation for 2008 and beyond are not credible

In its Reply Submission, the Applicant stated that VECC is simply wrong when it claims that the increased compensation cost attributable to the corporate reorganization is not offset by the reduction in shared services cost. The Applicant also stated that neither its employment nor compensation levels are growing dramatically. With the exception of executives, who receive incentive payments related to the Company's performance, the average compensation level increases are generally in the range of 2 to 3% per year.

Board Findings

The Mercer Report supports the current compensation levels found within the Utility. While there are some areas where the report might not be in strict conformity with the Board's directive in the 2006 Decision, for the purposes of this Decision, the Board is prepared to accept the Mercer Report as meeting the Board's directive.

The Mercer Report does not address, and accordingly there is no independent support for, the significant increases in compensation costs which form part of the Applicant's proposal.

As has been noted elsewhere, the Workforce Renewal Program accounts for some portion of the increase sought, but a substantial portion of the proposed increase in the compensation burden is not attributable to the WFR Program alone, nor specific increases within employee classes, but rather to increased numbers of employees, particularly within the management category, associated with the migration of employees from the parent to the Utility. For example, from 2006 to 2008 the number of management employees is slated to increase by 124% with a corresponding increase in payroll attributed to this class of 129%. This increase accounts for 9.4% of the overall increase in the compensation burden for this period. Further, the Management/non-union category increases 115% from 2006 to 2008 in employee count, and accounts for 43.4% of the overall increase sought. While the Board generally supports the repatriation of these functions, this effect on staffing levels and associated costs is noteworthy. Increases in staffing of this nature highlight the importance of heightened focus on productivity going forward.

As has been noted in other cases, and elsewhere in this Decision, requests for increased spending levels need to be placed within historical norms and increases need to be supported with evidence commensurate with the magnitude of the change sought.

The Board is prepared to accept that there may be some upward pressure on current compensation burdens, but not to the extent reflected in the Applicant's proposal, and the approved OM&A envelope reflects this finding.

Maintenance

The Applicant's maintenance program expenditures are $27.6 Million for 2008 and $29.9 Million for 2009. A breakdown of these amounts is shown in Table 9 below.

Table 10
Maintenance Costs
($ Million)

	2006 Historical	**2007 Bridge**	**2008 Test**	**2009 Test**
Preventive Maintenance Costs	6.3	8.8	8.6	9.0
Predictive Maintenance	1.4	1.4	1.5	1.6
Corrective Maintenance Costs	9.3	9.1	10.3	11.1
Emergency	6.9	6.5	7.3	8.2
Maintenance Programs Total	**23.9**	**5.8**	**27.6**	**29.9**

The Applicant stated that, as a consequence of its ageing infrastructure, it was experiencing an increase in maintenance costs however; it anticipated that its asset renewal and modernization program would allow it to decrease maintenance spending in the later years of its ten-year plan, as the population of deteriorating assets begins to decline relative to the overall asset population.

The Applicant also noted that its maintenance expenses were increasing to accommodate a more robust vegetation management approach, incorporating a new model for tree trimming designed to improve performance on the worst performing feeders, and for storm hardening which should reduce customer outages associated with severe storms. Vegetation management costs are projected to increase from the $2.6 Million 2006 historical level to $3.6 Million in the 2008 test year, an increase of over

71%. The Applicant's evidence was that even with this increased spending on vegetation management, overall expenditures in this area are less than they were in 1999 because the Applicant is managing these expenditures more efficiently and targeting them to the areas of greatest benefit with the help of the new vegetation management model.

CCC noted that increases are proposed in the area of maintenance while the Applicant is simultaneously ramping up its infrastructural renewal program significantly to replace its aging assets, where as replacement of assets should act to reduce maintenance costs.

Board Findings

Typically, additions to capital spending for plant replacement have the effect of reducing plant-related maintenance requirements. The converse is also true. Higher maintenance activity should result in lower capital replacement activity. This is not to suggest that the relationship is perfectly symmetrical, or linear.

This relationship is not well reflected to any degree in the Applicant's proposal. Both capital spending plans and maintenance costs rise quite significantly in comparison to historical year actual levels. The Applicant suggests that somewhere toward the end of its 10-year capital spending plan the maintenance budget will start to reflect the effect of newer and lower maintenance plant.

Elsewhere in this Decision the Board has remarked on the importance of placing a utility's spending plans within historical norms. That is not to say that exigent circumstances can't arise which will require measured departure from such norms. In those cases, compelling evidence must be presented commensurate with the extent of the departure. Ratepayers have a reasonable expectation that utility management is approaching capital and maintenance budgets, as well as other spending categories responsibly at all times, not just when rebasing or transitioning to performance based or incentive regulation. In the absence of clear evidence to the contrary, historical spending levels should be seen as normative, reflecting a responsible management's assessment of system needs, balancing current, mid and long-term requirements to avoid as much as possible lumpy and spiking spending patterns.

This observation is germane to our consideration of the Applicant's proposal for maintenance spending. The Board accepts that its enhanced approach to vegetation control may be prudent. The Board also considers that there is spotty evidence provided in support of the very significant increases over previous levels in both the capital spending plan and the maintenance budget.

Customer Service

In its pre-filed evidence, the Applicant summarized its Customer Services work program as the activities that are required to provide services to customers connected to their distribution system. The Applicant noted that it is obliged to meet the service levels stipulated in the OEB's *2006 Electricity Distribution Rate Handbook*.

Customer Services comprises two main operating areas: Meter-to-Cash and Customer Relationships.

The Meter-to-Cash group ensures that meters are safely and correctly installed, accurately read for billing, and that accounts are billed and collected in a timely manner.

The Customer Relationships team includes the call centre, a customer concern escalation group, and the Key Accounts team.

In addition to these main operating areas, Customer Services staff is engaged in a number of system development projects and activities. These include the following:

- Smart Meter Program
- Metering Services
- New Customer Information System
- Mobile Workforce Project
- Develop and Implement a New Customer Relationship Strategy
- Develop and Implement a Flat Rate Water Heater Conversion Program

The Applicant's proposed operating costs for Customer Services are shown in the table below.

Table 11
Customer Service
($ Million)

	2006 Historical	2007 Bridge	2008 Test	2009 Test
Metering Services	3.3	4.3	5.7	7.0
Smart Meter OPEX	-	0.2	2.5	2.9
Billing/Remittance	9.9	10.1	10.6	10.4
Collections	10.2	9.9	10.1	10.6
Customer Relationship Mgmt.	9.1	10.6	13.4	13.7
Field Services	4.9	6.2	7.8	8.8
Administration	2.1	0.6	0.8	1.1
Business Support	0.9	1.1	1.0	1.0
Outage Management	0.5	0.1	0.1	0.1
Total Customer Services	**41.1**	**43.0**	**51.9**	**55.6**

The proposed costs for the Test Years represent increases of 20.7% and 29.3%, respectively, over the Bridge Year.

Flat-Rate Water Heater Conversion was discussed at some length during the oral phase of the hearing. It would appear that the $2 Million required for each of the test years related to this program is aligned with the conservation initiative, Smart Meter use and the Time-of-Use billing programs.

SEC stated that both the projected increase in call volumes and projected increase in cost per call are based on conjecture rather than sound planning as they appear to assume the worst-case scenario for which the Applicant has budgeted accordingly. SEC further stated that the Company's proposal reflects a $1 Million "placeholder" to account for fees the Company expects to have to pay to the IESO for checking and transferring of Smart Meter readings at some point in the future. SEC stated that it is unclear as to how the $1 Million "placeholder" was arrived at, and recommended that this item be removed from the budget, or alternatively be subject to variance account treatment.

CCC also argued that there is no evidence to support the $1 Million "placeholder" for the future IESO Fees.

Further, CCC contended that there is no business case presented to support the program to phase out the flat-rate water heaters, and pointed to the Company's oral evidence as confirmation of this position. CCC also submitted that there has been no forecast date provided as to when smart meter implementation will occur and when TOU billing associated with the Smart Meter program will be in place.

VECC stated that it agreed with the motivation behind the customer care proposals in principle but disagreed with the cost consequences of these initiatives. VECC asserted that there is no business case for either the flat-rate water heater project or the efforts related to the TOU and Smart Meter projects. VECC noted that the roll-out of TOU rates is uncertain and depends to a degree on current pilot projects. VECC submitted that the Board should reduce the increase in customer care costs to 50% of the annual increase requested and that the cost consequences of these programs must be supported by an appropriate business case analysis.

In response, the Applicant stressed the need for the increased programs. It submitted that with the deployment of smart meters and the anticipated implementation of TOU rates, the Applicant will be experiencing increasing call volumes and an increased need to communicate with its customers. The Applicant reiterated the communications need to accompany the discontinuation of the Flat-Rate Water Heater service. Based on the number of smart meters already installed, and those yet to be installed, the Applicant considers the estimate of call centre demand to be conservative, and not based on a worst case scenario. While the Applicant agreed that a formal business case was not presented for the Flat-Rate Water Heater Conversion Program, it asserted that its approach to extend metering to this area of its business was rooted in two benefits: the ability to advance conservation and the ability to more appropriately assign water heating costs based on usage and thus eliminate cross-subsidization. The Applicant plans to have a dedicated communication group to work with customers who are expected to be resistant and unhappy with the change.

With regard to the future IESO Smart Meter Fees, the Applicant stated that the IESO has confirmed that the Applicant will be required to pay a fee for the checking and transfer of smart meter readings, although the fee structure has not yet been communicated. The Applicant decided upon the $1 Million "placeholder" based on an estimated equivalent to its manual meter reading costs, submitting that this is a reasonable estimate and should not be removed from the budget.

Board Findings

As with other parts of its submission, the Applicant's requested increases in the Customer Services portion of its budget are quite high. Also, as was pointed out by the intervenors, these cost increases are not substantiated by a strong business case. There are uncertainties and qualified predictions in the information presented by the Applicant in the areas of call centre activities, increases in billing costs, conversion of Flat Rate Water Heaters, smart meter data collection and storage, and anticipated IESO charges.

The general spending increase will allow the Applicant to proceed with its Customer Services programs, although at a reduced rate. It is possible for the Applicant to seek productivity improvements in this area to better manage some of these initiatives, such as better communication strategies to reduce the volume and duration of customer inquiries on hot water rental heater conversions, smart meter, and TOU rate implementation.

The rollout of the Smart Meter and Time-of-Use regimes and the costs associated with them will not fully mature in 2008. As is stated elsewhere in this Decision: "… the issue is not necessarily that smart meter (installation) expenditures may not materialize; rather, the concern is the potential of timing differences in the actual expenditures from those forecast." In any event, the costs associated with the IESO future fees will require an industry-wide response by the Board once the proceeding regarding the IESO's fees resumes. In the meantime, the IESO's fees are recordable in variance account 1556. The Applicant shall reduce its proposed revenue requirement by the $1 Million amount in this regard. In other words, this is outside the Board's OM&A spending envelope.

5. Other Specific Matters

5.1 Residential Load Control Program

The Company is seeking approval for recovery in rates of amounts to continue its current PeakSaver residential load control program for each year. The requested funding ($1.6 Million for 2008, $1.8 Million for 2009) is to maintain the demand response capacities installed prior to 2008 and to support the demand response operation to activate demand reductions. The Company has stated that the OPA has not indicated that it would fund the program.

The request also includes amounts ($326,000 for 2008, $338,000 for 2009) for the Company's CDM Programs Governance Group (the "Governance program"), which ensures that appropriate governance procedures and processes are implemented and enforced. The Company plans to participate in the OPA residential load control standard program in the years 2008-2010.

Intervenors argued that as the Company has not demonstrated that the OPA will not fund the PeakSaver program going forward, the Board should not approve recovery of these amounts in rates until the Company provides such evidence. One party questioned whether the Company's preference for funding the program by distribution rates would result in a shared savings mechanism that would not be available if the program was funded by the OPA. SEC argued that the Board should not allow more than $326,000 for the Governance component of the program going forward.

Board Findings

The Board's concern is that the Company's ratepayers do not pay for this activity both through distribution rates and through OPA's charges for the same province-wide program, the charges of which are passed to all ratepayers through commodity rates. The Board finds the Company's evidence and arguments in support of its proposal wanting. On the evidence adduced, the Board is not convinced that the Company cannot obtain funding from the OPA for a program which is now part of the OPA's standard programs so that the Applicant's ratepayers will not be double burdened. The Board finds that the proposed costs associated with the Company's residential load control program should not be included in rates at this time. The Company should pursue funding of the program through the OPA. Should the Company not be successful, it is authorized to employ a deferral account to record the costs not included in rates for future review by the Board. At that time the Company is expected to provide convincing evidence as to why it has not been successful in obtaining funding through the OPA.

As it is not clear from the Company's evidence and argument how much of the budgeted amounts associated with the Governance program are directly related to the PeakSaver program, the regulatory treatment of the two programs shall be the same, and no amounts for the Governance program will be included in rates at this time. Should the Company establish the deferral account referred to above, at the time the Company brings the account to the Board for review, it shall provide evidence that establishes the Governance program amounts that are linked to the PeakSaver program.

5.2 Line Losses

The determination of the Company's revenue requirement incorporates a provision for a Distribution Loss Factor of 3.1%. Differences between this level and actual levels are recorded in the Company's RSVA-Power Account.

Pollution Probe argued that allowance for line losses should be reduced to 2.9% on the basis that the actual rates have been lower than 3.1% since 2002 and 2.9% was the observed rate for 2005 and 2006. Pollution Probe also argued that the RSVA-Power account should no longer capture variations for line losses on the rationale that this would incent the Company to lower line losses.

SEC stated that the Pollution Probe's plan does not have enough information to form the basis of a policy decision at this point. SEC also noted that this issue may be best dealt with in a generic proceeding. CCC supported the reduction to 2.9% but did not support the elimination of the variance account.

Board Findings

The Board is generally concerned about line losses and encourages utilities to address this matter in a cost effective way. In that regard the Board has commenced an initiative in January 2008 to better understand this issue. In the Board's view it would not be appropriate for the Board to direct a different regulatory treatment for the Applicant than for the sector as a whole by eliminating the provision for a true-up. Moreover, while there is always room for improvement in this area, the Applicant's line losses do not appear to be excessive. The Board does not accept Pollution Probe's proposal and accepts the Company's provision for line losses at 3.1%.

5.3 Distributed Generation

Currently, virtually all of the electricity for Downtown Toronto is supplied through two transmission lines. Concern about ability to supply Downtown Toronto in the future has caused the OPA to consider a third line, at a capital cost of $600 Million.

Pollution Probe noted that neither the Government of Ontario nor Toronto Hydro support a third line. The solution, according to Pollution Probe, is more distributed generation ("DG").

Pollution Probe noted that 300MW of DG would eliminate the supply problem but acknowledged the Applicant's possible limitations as to the size of installation which could be accommodated on the Applicant's distribution system. Pollution Probe therefore proposed that the embedding of thirty 10MW generators within Toronto would be sufficient to avoid the third line.

Pollution Probe also contended that, along with distributed generation, CDM could further reduce the requirement for this additional supply. Pollution Probe compared the budgets for the CDM ($22Million) and Supply-Side Infrastructure ($906Million) programs, inferring a lack of strong commitment to CDM by the Applicant.

The Applicant asserted that the issue of whether or not there should be new transmission supply to Toronto is a transmission issue that should be addressed elsewhere, such as in the IPSP proceeding currently before the Board. It also suggested that issues concerning distributed generation, transmission and distribution cost responsibility and rate design are being reviewed by the Board at this time in other generic proceedings.

The Applicant contended that possible solutions examined include connections for DG and self-generation, but that these must make sense from engineering, economic and regulatory perspectives. For example, DG customers are required to fully fund connections to the network since they do not currently pay distribution or use-of-system charges if they do not take load. This system protects load ratepayers from subsidizing the costs for distributed generators to connect to the Applicant's system.

Board Findings

Leaving aside the question of the need for the third transmission line, which the Board acknowledges is best addressed through other proceedings, including the IPSP application currently before the Board, the Board considers that the Applicant should facilitate connections for DG and self-generation, where they can be implemented practically and economically, both from the perspective of the generator and of the Applicant and its load customers.

With regard to conservation and demand management, it would be premature for the Board to comment on the specific suggestions made by Pollution Probe, as the IPSP proceeding has not yet been completed.

The Board observes that the Applicant's study of distributed generation has not been rigorous. Therefore, the Board directs the Applicant to conduct a study into the capability, costs and benefits of incorporating into the Applicant system, a significant (up to 300MW) component of bi-directional distributed generation in Toronto. In this study, the Applicant should also incorporate the outcomes, as they pertain to distributed generation, of two items which are currently being considered by the Board: 1) enabler lines and their connection costs; and 2) the IPSP. The study should also be responsive to any new policy or regulatory developments in these areas. This study shall be filed as part of the Company's next application dealing with rates beyond the test period dealt with in this proceeding.

6. Cost Allocation and Rate Design

6.1 Revenue-to-Cost Ratios

Column B in the Table 12 below shows the Company's proposed revenue to cost ratios (in %) for each rate class. The ratios in Column A are those derived from the 2006 Informational Filing, Run 2. The ranges of ratios in Column C are the Board's targets contained in the Board's Application of Cost Allocation for Electricity Distributors Report, dated November 28, 2007.

Table 12
Revenue to Cost Ratios

Customer Class	2006 Informational Filing Run 2 [A]	Proposed Ratios per Applicant [B]	Board-Sanctioned Ranges [C]
Residential	84.8	85.0	85 – 115
GS < 50 kW	94.7	97.6	80 – 120
GS 50-1000 kW	140.5	130.5	80 – 180
Intermediate 1000-5000 kW	148.0	136.8	80 – 180
Large Use	114.8	110.3	85 – 115
Unmetered Scattered Load (USL)	44.3	48.2	80 – 120
Streetlighting	10.7	25.1	70 – 120

Parties took issue with the proposed ratios for the Unmetered Scattered Load ("USL") rate class and the Streetlighting rate class as these are below the bottom of the Board-sanctioned ranges. With respect to Streetlighting, the issue for some parties was that the customer, TH Energy, provides the service to the City of Toronto, the indirect owner of the Utility, giving rise to possible non-compliance with the Board's *Affiliate Relationships Code.*

Board Findings

As the Board has noted[36], cost causality is a fundamental principle in setting rates. However, the Board has also noted that observed limitations in data affect the ability or desirability of moving immediately to revenue to cost framework around 100%.

With respect to the Company's proposals, the Board is prepared to adopt the principle that, where the proposed ratios are outside the Board's ranges (shown in Column C), there should be a move of no less than 50% toward the bottom of the ranges for a given rate class from what has been reported in the Informational Filing Run 2 (Column A). The Board adopts this principle and applies it to bring the revenue to cost ratio for the USL rate class to 62% and the Streetlighting rate class to 40%.

In so finding, the Board has concluded that the *Affiliate Relationships Code* has no application in this aspect of the Company's proposal. As the Applicant points out, the rate class is open for any entity that satisfies the eligibility criteria for that rate class. The fact that the entity is an affiliate is not pertinent.

The Board finds it reasonable, and it so directs, that the higher revenue from the USL and Streetlighting rate classes be allocated proportionally to the Intermediate and Large Use rate classes, as these two classes exhibit the greatest distance from 100%.

6.2 Monthly Fixed Charges

The Company's existing and proposed monthly fixed charges are shown in Table 13.

[36] Board Report *Application of Cost Allocation for Electricity Distributors Report*, November 28, 2007

Table 13
Monthly Fixed Charges
($)

Customer Class	[A] Existing Monthly Fixed Charges	[B] Proposed Fixed Charges for 2008	[C] Proposed Fixed Charges for 2009
Residential	12.00	14.85	16.85
GS < 50 kW	16.07	19.37	21.44
GS 50-1000 kW	25.82	29.78	32.69
Intermediate 1000-5000 kW	717.42	725.80	705.35
Large Use	2,758.30	2,883.81	2,639.04
Unmetered Scattered Load (USL)			
Service Charge	1.99	2.96	3.42
Per connection	0.29	0.33	0.35
Streetlighting	0.26	0.66	0.89

Parties raised a number of concerns regarding the proposed ratios, including the hardship they might cause for low volume consumers, the injurious effect they might have on consumers' conservation habits, and the prematurity of the proposed changes in light of the Board's ongoing initiative of reviewing rate design matters for the electricity distribution sector.

Board Findings

In its Cost Allocation Report, the Board stated that the floor for the monthly service charges should be the avoided costs and that the ceiling should be the avoided costs plus the allocated customer costs.

The Company's proposed monthly fixed charges do not conflict with the Board's guidance with respect to these charges. The Board finds the Company's proposed monthly charges to be reasonable and approves them. In so finding, the Board is persuaded by the Company's argument that its proposals would not have any injurious effect on the conservation habits of customers.

7. Deferral and Variance Accounts

The Company proposed to dispose of balances in certain deferral/variance accounts, to continue certain accounts, and to establish two new accounts.

Disposition of the Balances

The Company requested disposition of the forecast April 30, 2008 balances, shown in the table below (positive amounts represent charges to customers, amounts in brackets represent credits to customers).

Table 14
Proposed Accounts Dispositions ($ Millions)

	1590	**1571**	**1580**	**1592**
	Regulatory Assets	Pre-Market Opening	RSVA – Wholesale Market Charges	Post-April 2006 PILs Account
Forecast balances to April 30, 2008	**$1.5**	**($4.0)**	**($14.6)**	**($6.3)**

The Company's proposal is to credit the net $23.3 Million to customers relating to accounts 1590, 1571, 1580 and 1592, by means of a rate rider credit over a 12-month period from May 1, 2008.

<u>Board Findings</u>

Intervenors did not take issue with the calculated balances or the proposed method of disposition. The Board deals with certain disposition issues below, which in the Board's view require specific findings or comments. Unless otherwise noted, the Board approves the Company's proposals..

Principal Balances

Board staff noted that the balances in accounts 1590 (Regulatory Assets) and 1592 (Post-April 2006 PILs) include forecast balances of principal. In the electricity distribution sector it is not the Board's practice to clear forecast balances which include principal.

Board staff also referred to the Board's Phase 2 Decision for the Review and Recovery of Regulatory Assets for the five large distributors (RP-2004-0117, RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064), and submitted that the Company's proposal to dispose of account 1590 before the final balance has been determined does not reflect a proper true-up. The Phase 2 Decision specifies that the rate rider associated with account 1590 be removed as of May 1, 2008. Once the residual balance in account 1590 is finalized, the residual balance is to be disposed at a future hearing. The final balance in account 1590 cannot be confirmed until after the current recovery period has expired, i.e. after April 30, 2008.

Board Findings

To the extent possible and practical, the balances of variance and deferral accounts that are approved for clearance should be measured at the same date for all distributors. In a few electricity rate cases, the Board has accepted settlement agreements that include clearance of deferral and variance accounts based on measurement dates other than the date of the most recent audited financial statements. In most other cases not involving settlement agreements, the Board usually approved only the disposition of actual audited balances.

The Board does not find any compelling reasons to make an exception to its general policy in this case and will not dispose of the 1590 account at this time.

With respect to account 1592, as the Board has commenced a combined proceeding which was announced on March 3, 2008 to deal with matters concerning pre April 30, 2006 PILs variances in account 1562, which may inform matters pertaining to the post April 30, 2006 PILs variance in account 1592, it will not dispose of this account in this proceeding. The Board notes that the Company withdrew its request in its initial filing to dispose of the balances in the 1562 account.

Disposition of Retail Settlement Variance Accounts (RSVAs)

Of its RSVA accounts, the Company proposed to dispose of account 1580 (Wholesale Market Services Charges) only and not the other RSVA accounts (One-time, Connection, Network, and Low Voltage Charges).

Board staff noted that except for the RSVA Power account, which is governed under the Bill 23 process and reviewed quarterly by the Board in a separate process, it is the Board's usual practice to dispose of the balances in all the RSVA accounts.

Board Findings

On February 19, 2008, which is after the completion of the argument phase, the Board announced an initiative for the review and disposition of commodity account 1588 (RSVA-Power). The Board noted that, as part of this initiative, it will consider whether to extend this initiative to other accounts that are similar in nature, and named certain RSVA accounts. The Board finds that it would be appropriate to await the outcome of this initiative and therefore will not order disposition of the non-commodity RSVA accounts in this proceeding, with one exception.

Notwithstanding this initiative, the Board finds that disposition of account 1580 is appropriate at this time, as proposed by the Company. This account contains a large customer credit balance and requiring the Company to continue to accumulate interest on this large balance for a possibly extended period of time would not be reasonable.

Continuation of and New Deferral and Variance Accounts

The Company proposed to continue certain accounts and proposed two new accounts. The Company proposed to continue the following existing accounts:

Low Voltage Charges (1550)
RSVA – Wholesale Market Services (1580)
RSVA – One Time Charges (1582)
RSVA – Network (1584)
RSVA – Connection (1586)
RSVA – Power (1588)
Regulatory Assets (1590)
Tax Variance (1562)

The Company requested the following two deferral/variance accounts: OEB Cost Assessments/Intervenors' Costs Awards/OEB Mandated Studies Account (for convenience "regulatory costs" account) and Capital Contributions account.

The regulatory costs account would track the differences in expenses reflected in rates and actual expenses associated with the named activities. The proposed amounts to be reflected in rates were $8.2 Million for 2008 and $7.8 Million for 2009.

The Capital Contributions account would track the difference between the rate impacts associated with actual capital contributions to Hydro One Networks and the impacts of contributions included in rates. The rate impacts included in the proposed rates were based on contributions of $5.0 Million for 2008 and $10.0 Million for 2009.

Board Findings

Variance and deferral accounts are governed by the Accounting Procedures Handbook (APH) and associated letters of the Board. All deferral and variance accounts are open to all electricity distributors and may be used according to the rules stated in the APH and associated documentation, unless specific Board findings apply for a utility with respect to the use of these accounts or other accounts. Therefore, there is no need for the Board in this proceeding to approve or not approve of the continuation of existing accounts. Similarly, the two proposed new accounts are of general sector applicability; they are not exclusive to the Applicant. As such, this matter requires a sector-wide approach through the APH or direction by the Board through another instrument.

8. Implementation

8.1 Cost of Capital Update

In mid-2006, the Board initiated a consultative process to examine the cost of capital applicable to the Ontario electricity distribution sector. This process was conducted in conjunction with the development of the 2nd Generation Incentive Regulation plan. The product of these consultations was the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Board Report"), issued December 20, 2006. The Board Report considered the extensive consultation record and established, in part, guidelines for setting and updating the cost of capital parameters for distribution rate-setting from 2007 onwards, including the return on common equity ("ROE"), the deemed short-term debt rate, and, as appropriate, the deemed long-term debt rate.

The Board Report established that the approved ROE to be used for rate-setting purposes should be calculated by application of the formula in Appendix B of the Board Report. In setting the ROE for the establishment of 2008 rates, the Board has used the Consensus Forecasts and published Bank of Canada data for January 2008, in accordance with the Board's guidelines. In fixing new rates and charges for Hydro 2000 the Board has applied the policies described in the Board Report. Based on the final 2007 data published by Consensus Forecasts and the Bank of Canada, the Board has established the ROE for 2008 to be 8.57%.

The Board Report also established that the short-term debt rate should be updated using the methodology in section 2.2.2 of the Board Report. The Board has set the short-term debt rate at 4.47% using data from Consensus Forecasts and the Bank of Canada for January 2008.

Based on the above updates and in accordance with the settlement agreement, for purposes of setting 2008 rates, the Board-approved capitalization and cost of capital for the Applicant is as follows:

Table 15
Board-approved 2008 Capitalization and Cost of Capital

Capital Component	% of Total Capital	Cost (%)
Short-Term Debt	4.0	4.47%
Long-Term Debt	58.5	5.48%
Common Equity	37.5	8.57%

8.2 Draft Rate Order

This Decision will result in the approval of rates for test years 2008 and 2009. The Board has made numerous findings throughout this Decision which would change the revenue requirements and deficiency claimed by Toronto Hydro for 2008 and 2009. The Board has also made certain findings regarding the disposition of balances in deferral and variance accounts. Further, the Board has made findings on cost allocation and rate design matters that would further affect the rates for certain rate classes. These are to be properly reflected in a Draft Rate Order incorporating an effective date of May 1, 2008 for the new rates.

As the Applicant's current rates were declared interim as of May 1, 2008, given the date of this Decision there will be a difference between the revenue collected under the existing rates and the revenue that would have been collected if the new rates were implemented May 1, 2008. Depending on the date of implementation of the new rates, the new rates shall be set so as to recover the annualized revenue requirement over the remaining period of the 2008 rate year. For example, if the Applicant will be able to implement the new rates on June 1, 2008, the new rates shall reflect the fact that there will be only 11 months to April 30, 2009.

As for 2009 rates, this Decision will govern the establishment of those rates subject to the cost of capital parameter updates and possibly other Board decisions that might apply. The Applicant shall apply in a timely fashion to receive approval for the 2009 rates to be effective May 1, 2009.

In filing its Draft Rate Order for 2008 rates, the Company should attach appropriate documentation in support of its rates, disposition of deferral/variance accounts, disposition of other amounts, and the allocation of the approved revenue requirement to the rate classes.

A Rate Order will be issued after the steps set out below are completed.

1. The Company shall file with the Board, and shall also forward to intervenors, a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 14 days of the date of this Decision.

2. Intervenors may file with the Board and forward to the Company responses to the Company's Draft Rate Order within 21 days of the date of this Decision.

3. The Company shall file with the Board and forward to intervenors responses to any comments on its Draft Rate Order within 27 days of the date of this Decision.

A cost awards decision will be issued after the steps set out below are completed.

1. Intervenors eligible for costs awards shall file with the Board and forward to the Company their respective cost claims within 28 days from the date of this Decision.

2. The Company may file with the Board and forward to intervenors eligible for cost awards any objections to the claimed costs within 35 days from the date of this Decision.

3. Intervenors, whose cost claims have been objected to, may file with the Board and forward to the Company any responses to any objections for cost claims within 42 days of the date of this Decision.

The Company shall pay the Board's costs of, and incidental to, this proceeding upon receipt of the Board's invoice.

DATED at Toronto, May 15, 2008

ONTARIO ENERGY BOARD

Original Signed By

Paul Sommerville
Presiding Member

Original Signed By

Paul Vlahos
Member

Original Signed By

David Balsillie
Member

Appendix "A" - Issues List

EB-2007-0680

MAY 15, 2008

Issues List

1 Threshold Issue

1.1 Should the Board proceed with reviewing the applicant's proposal for multi-year rebasing?	**No Settlement**

2 Operating Costs

2.1 Is the proposed level of Operation, Maintenance, Administration and General Expenses acceptable?	**No Settlement**
2.2 Has the applicant addressed the Board's concerns related to distribution expenses paid to affiliates with a response that provides reasonable costs?	**No Settlement**
2.3 Are the procurement policy and the costs that flow from it appropriate?	**Issue Narrowed**
2.4 Are the proposed levels of Depreciation and amortization expense acceptable?	**Issue Narrowed**

3 Operating Revenue

1.1 Are the proposed revenue offsets reasonable for rate determination?	**No Settlement**

4 Taxes

4.1 Is the PILs provision reasonable?	**Complete Settlement**
4.2 Are the proposed levels for Capital Taxes and Property Taxes appropriate?	**Issue Narrowed**

5 Rate Base

5.1 Is the proposed level of capital expenditures acceptable?	**No Settlement**
5.2 Is the proposed working capital appropriate?	**Issue Narrowed**

6 Cost of Capital and Rate of Return

6.1 Is the applicant's proposal for adjusting the return appropriate?	**Complete Settlement**
6.2 Is the applicant's forecast of debt reasonable?	**Complete Settlement**

7 Load Forecast

7.1 Is the applicant's load forecast acceptable?	**No Settlement**

8 Cost Allocation and Rate Design

8.1 Did the applicant apply the Board's cost allocation methodology correctly?	**Complete Settlement**
8.2 Are the proposed revenue to cost ratios reasonable?	**No Settlement**
8.3 Are the Fixed Monthly Charges reasonable?	**No Settlement**
8.4 Are the loss adjustment factors reasonable?	**No Settlement**

9 CDM

9.1 Is it appropriate to provide funding for the residential load control programme as proposed by the applicant, given that the applicant is also seeking funding from the OPA for a residential load control program?	**No Settlement**
9.2 Is it appropriate to provide incremental funding for governance of all existing CDM programmes as proposed by the applicant?	**No Settlement**

10 Smart Meters

10.1 Are the proposed costs for smart meters appropriate?	**No Settlement**

11 Deferral and Variance Accounts

11.1 Is the proposal for the continuation of existing variance and deferral accounts appropriate?	**Issue Narrowed**
11.2 Is the proposal for the establishment of any new variance accounts appropriate?	**No Settlement**
11.3 Is the proposal for the amounts and disposition of Toronto Hydro's existing deferral and variance accounts appropriate?	**No Settlement**
11.4 Should there be a variance account for capital expenditures within the test period?	**No Settlement**

12 Rate Implementation

12.1 Is the proposal for 2009 and 2010 rates justified?	**No Settlement**
12.2 Is the proposal for the rate implementation appropriate?	**No Settlement**

Appendix “B” – Intervenors

EB-2007-0680

May 15, 2008

TORONTO HYDRO ELECTRIC SYSTEM LIMITED

EB-2007-0680
APPLICANT & LIST OF INTERVENORS

May 15, 2008

	Utilities	**Rep. and Address for Service**
1.	Toronto Hydro Electric System Limited	Glenn Winn Toronto Hydro Electric System Limited 14 Carlton Street Toronto ON M5B 1K5 Tel: 416-542-2517 Fax: 416-542-2776 Email: regulatoryaffairs@torontohydro.com
	Counsel for applicant	J. Mark Rodger Borden Ladner Gervais LLP Lawyers, Patent & Trade-mark Agents Toronto ON M5G 3Y4 Tel: 416-367-6190 Fax: 416-361-7088 Email: mrodger@blgcanada.com

	INTERVENORS	**REP and ADDRESS FOR SERVICE**
1.	Consumers Council of Canada	Julie Girvan Consumers Council of Canada 2 Penrose Road Toronto ON M4S 1P1 Tel: 416-322-7936 Fax: 416-322-9703 Email: jgirvan@ca.inter.net

	AND	Robert B. Warren Weirfoulds LLP The Exchange Tower, Suite 1600 P.O. Box 480 130 King Street West Toronto ON M5X 1J5 Tel: 416-947-5075 Fax: 416-365-1876 Email: rwarren@weirfoulds.com
2.	Energy Probe Research Foundation ("Energy Probe")	David S. MacIntosh c/o Energy Probe 225 Brunswick Avenue Toronto ON M5S 2M6 Tel: 416-964-9223 ext. 235 Fax: 416-964-8239 Email: DavidMacIntosh@nextcity.com
3.	Hydro One Networks Inc. ("Hydro One")	Glen MacDonald Senior Advisor Regulatory Research and Administration Regulatory Affairs Hydro One Networks Inc. 8th Floor, South Tower 483 Bay Street Toronto ON M5G 2P5 Tel: 416-345-5913 Fax: 416-345-5866 Email: regulatory@HydroOne.com
4.	Pollution Probe Foundation	Murray Klippenstein Klippensteins Barristers & Solicitors 160 John Street, Suite 300 Toronto ON M5V 2E5 Tel: 416-598-0288 Fax: 416-598-9520 Email: murray.klippenstein@klippensteins.ca

	AND	Basil Alexander Klippensteins Barristers & Solicitors 160 John Street, Suite 300 Toronto ON M5V 2E5 Tel: 416-598-0288 Fax: 416-598-9520 Email: basil.alexander@klippensteins.ca
	AND	Jack Gibbons Public Interest Economics 625 Church Street, Suite 402 Toronto ON M4Y 2G1 Tel: 416-926-1907 ext. 240 Fax: 416-926-1601 Email: jgibbons@pollutionprobe.org
5.	Power Stream Inc.	Sarah Griffiths Power Stream Inc. 2800 Rutherford Road. Vaughan ON L4K 2N9 Tel: 905-417-6900 ext. 8138 Fax: 905-303-2006 Email: sarah.griffiths@powerstream.ca
6.	Schools Energy Coalition	Mr. John De Vellis Counsel for Schools Energy Coalition Shibley Righton LLP Barristers and Solicitors 250 University Avenue, Suite 700 Toronto, ON M5H 3E5 Tel: 416-214-5232 Fax: 416-214-5432 Email: john.devellis@shibleyrighton.com

	AND	Mr. Bob Williams Co-Ordinator Ontario Education Services Corporation c/o Ontario Public School Boards' Association 439 University Avenue, 18th Floor Toronto, ON M5G 1Y8 Tel: 416-340-2540 Fax: 416-340-7571 Email: bwilliams@opsba.org
	AND	Ms. Rachel Chen Institutional Energy Analysis, Inc. 250 University Avenue, Suite 700 Toronto, ON M5H 3E5 Tel: 416-214-5298 Fax: 416-214-5498 Email: rachel.chen@ieai.ca
7.	Vulnerable Energy Consumers Coalition	Vulnerable Energy Consumers Coalition Michael Buonaguro Counsel c/o Public Interest Advocacy Centre 34 King Street East, Suite 1102 Toronto ON M5C 2X8 Tel: 416-767-1666 Fax: 416-767-2229 Email: mbuonaguro@piac.ca Mr. James Wightman Econalysis Consulting Services 34 King Street East, Suite 1102 Toronto ON M5C 2X8 Tel: 416-348-0640 Fax: 416-348-0641 Email: jwightman@econalysis.ca

Appendix “C” – Settlement Agreement

EB-2007-0680

May 15, 2008

EB-2007-0680

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

<u>REVISED</u>

PROPOSED SETTLEMENT AGREEMENT

DECEMBER 4, 2007

EB-2007-0680: PROPOSED SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is for the consideration of the Ontario Energy Board ("the Board") in its determination, under Docket No. EB-2007-0680, of rates for 2008, 2009, and 2010 for Toronto Hydro-Electric System Limited ("THESL").

By Procedural Order No.1 dated September 21, 2007, the Board scheduled a Settlement Conference to commence November 20, 2007. The Settlement Conference was convened, in accordance with Procedural Order No. 1, with Mr. George Dominy as facilitator. The Settlement Conference proceeded until November 22, 2007.

No comprehensive settlement was reached. However, in some instances the parties reached complete settlement on a specific issue, or agreed that an issue could be narrowed. This Agreement identifies the issues on the Board's list for which multi-party settlement or agreement on narrowing of the issue has been reached.

No agreement was reached on the threshold issue identified by the Board concerning the length of the test period (i.e., whether Board Orders should be issued for 2008, 2009, and 2010 or for fewer rate years). The proposed narrowings or settlements of specific issues set out below are intended to be neutral on the threshold issue and without prejudice to any party's position on, or the eventual determination of, that issue.

The Issues List as determined by the Board's decision dated October 15, 2007 is attached as Appendix A to the Agreement. The parties agree that this Agreement and the Appendix form part of the record in the proceeding.

Each of the issues identified below falls within one of the following three categories:

1. An issue for which there is no settlement;
2. An issue for which there is a proposed narrowing of scope, agreed to by THESL and other parties, but for which one or more parties may disagree or take no position; and,
3. An issue for which complete settlement was reached.

For the purposes of this Agreement, the term “no position” may apply to parties who were involved in negotiations on an issue but who ultimately took no position on that issue, as well as parties who were not involved in negotiations on that issue at all.

The parties agree that all positions, information, documents, negotiations and discussion of any kind whatsoever which took place or were exchanged during the Settlement Conference are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Agreement.

The role adopted by Board Staff in Settlement Conferences is set out on page 5 of the Board’s Settlement Conference Guidelines. Although Board Staff is not a party to this Agreement, “Board Staff who participate in the settlement conference are bound by the same confidentiality standards that apply to parties to the proceeding”, as noted in the Guidelines.

The evidence supporting the settlement for, or agreement on narrowing of scope for each issue where this was achieved is set out in that section of the Agreement.

The following parties participated in the Settlement Conference:

Toronto Hydro Electric System Limited (“THESL”)
Consumers Council of Canada (“Consumers Council”)
Energy Probe Research Foundation (“Energy Probe”)
Pollution Probe Foundation (“Pollution Probe”)
School Energy Coalition (“Schools”)
Vulnerable Energy Consumers Coalition (“VECC”)

STATEMENT OF PROPOSED SETTLEMENT BY ISSUE

The complete Issues List, as approved by the Board on Oct 15, 2007, is set out below, along with any scope-narrowing proposal agreed upon by any of the intervening parties and THESL. Details of the proposed scope-narrowing, along with references to the corresponding evidence are provided under each defined issue.

1 Operating Costs

1.1 Is the proposed level of Operation, Maintenance, Administration and General Expenses acceptable?

No Settlement

1.2 Has the applicant addressed the Board's concerns related to distribution expenses paid to affiliates with a response that provides reasonable costs?

No Settlement

1.3 Are the procurement policy and the costs that flow from it appropriate?

Narrowing of the issue:

Parties accept the evidence with respect to THESL's procurement policy *per se*. However, specific costs for items procured using the procurement policy remain unsettled.

The following parties agree with this narrowing of the issue: Consumers Council, Energy Probe, Schools, VECC, and THESL.

The following parties take no position on this issue: Pollution Probe

Evidence References:
Exhibit C2, Tab 3, Schedule 1
Exhibit C2, Tab 3, Schedule 1, Appendix A
Exhibit R1, Tab 1, Schedule 1.25

1.4 Are the proposed levels of depreciation and amortization expense acceptable?

Narrowing of the issue:

Parties accept the depreciation and amortization rates and calculation methodology proposed by THESL, with the exception of the treatment of stranded meter costs. The specific levels of proposed depreciation and amortization costs, inasmuch as they are determined by changes in the value of ratebase, remain unsettled.

The following parties agree with this narrowing of the issue: Consumers Council, Energy Probe, Schools, VECC, and THESL.

The following parties take no position on this issue: Pollution Probe

Evidence References:
Exhibit D1, Tab 6, Schedule 3
Exhibit D1, Tab 6, Schedule 4
Exhibit D1, Tab 13, Schedule 1
Exhibit D1, Tab 14, Schedule 1
Exhibit R1, Tab 1, Schedule 4.13
Exhibit R1, Tab 1, Schedule 4.13, Appendix A

2 Operating Revenue

2.1 Are the proposed revenue offsets reasonable for rate determination?

No Settlement

3 Taxes

3.1 Is the PILs provision reasonable?

Complete Settlement

Parties accept THESL's tax calculation methodology, subject to adjustments to the level of the PILs allowance to reflect the Board's Decision, and to incorporation of the effects of known changes to GST and federal tax rates through the continuing use of variance accounts. See also Issue 10.1

The following parties agree with the settlement of this issue: Consumers Council, Energy Probe, Schools, VECC, and THESL.

The following parties take no position on this issue: Pollution Probe

Evidence References:
Exhibit H1, Tab 1, Schedule 1
Exhibit R1, Tab 1, Schedule 5.1
Exhibit R1, Tab 1, Schedule 10.7

3.2 Are the proposed levels for Capital Taxes and Property Taxes appropriate?

Narrowing of the issue:

THESL's methodology and tax calculations are accepted by the parties. The specific levels of tax remain unsettled because they are a function of ratebase levels.

The following parties agree with this narrowing of the issue: Consumers Council, Energy Probe, Schools, VECC, and THESL.

The following parties take no position on this issue: Pollution Probe

Evidence References:
Exhibit H1, Tab 1, Schedule 1

4 Rate Base

4.1 Are the proposed capital plan and level of capital expenditures acceptable?

No Settlement

4.2 Is the proposed working capital appropriate?

Narrowing of the issue:

Parties accept the results of THESL's lead-lag study (i.e., the Navigant Study) and working capital calculation methodology. There is no settlement on the specific level of the working capital allowance because of its dependence on other unsettled items.

The following parties agree with this narrowing of the issue: Consumers Council, Energy Probe, Schools, VECC, and THESL.

The following parties take no position on this issue: Pollution Probe

Evidence References: Exhibit D1
Exhibit D1, Tab 15, Schedule 1
Exhibit D1, Tab 15, Schedule 2
Exhibit D1, Tab 15, Schedule 3
Exhibit D1, Tab 15, Schedule 4
Exhibit D1, Tab 16, Schedule 1

4.3 Will the proposed capital expenditures permit a significant expansion of distributed generation in downtown Toronto by 2011?

No Settlement

<u>5 Cost of Capital and Rate of Return</u>

5.1 Is the applicant's proposal for adjusting the return appropriate?

Complete Settlement

Preamble

THESL's Cost of Capital evidence proposes that Allowed Return on Equity be determined prior to the test year or, if applicable, the test years, using the Board's methodology as detailed in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, issued December 20th, 2006. THESL will update the test year Revenue Requirement to reflect the updated ROE. THESL has not proposed that its cost of debt be updated during the three test years, but instead proposed that the cost of debt be set for all years based on the evidence and forecasts provided in Exhibit E1.

Settlement

Parties agree that the Allowed Return on Equity will be updated prior to the beginning of the 2008 test year, and, if necessary, the 2009 and 2010 rate years, using the Board's ROE methodology.

Additionally, parties agree that the <u>forecast</u> cost of short term debt and new long-term debt in a given test year will be updated using the Board's methodology for the deemed long term and short term debt rates to determine the corresponding rates applicable in that test year. This methodology is defined in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, dated December 20, 2006, in Section 5.1, Cost of Capital (the "Board Guidelines").

Parties also agree that in the event this proceeding results in a rate order for 2009, the actual amount of, and interest rate applicable to, any new long term debt issued in 2008 will be reflected in the determination of revenue requirement for the 2009 test year. That is, the actual cost of embedded debt, subject to the Board Guidelines, will be updated prior to the commencement of the next test year. If applicable, an adjustment will be made in 2010, so that the 2010 revenue requirement will be updated to reflect those parameters for debt actually issued during 2008 and 2009.

THESL will file, prior to the beginning of each rate year (2008, 2009, and 2010), its projections for cost of capital (i.e., amount, timing, and cost of debt and equity) and the associated change in revenue requirement for the forthcoming test year, once the forecast ROE and debt rates are determined in accordance with the Board's methodology. THESL will provide intervenors of record in this proceeding a copy of its filing in order to allow intervenors to submit any comments to the Board within 5 working days.

Rationale

By proposing to use the Board's methodology for determining the long term and short term debt rates, adjusting the cost of debt is nearly as mechanistic as adjusting the Return on Equity. Parties agree that the method described above adequately protects both ratepayers and the company from exogenous changes in interest rates and debt timing issues over the three-year test period. This mechanism mimics the adjustment that would be made under single year cost of service applications, in that the embedded (i.e., actual) cost of issued debt is reflected in rates for all years subsequent to the test year.

The following parties agree with the settlement of this issue: Consumers Council, Energy Probe, Schools, VECC, and THESL.

The following parties take no position on this issue: Pollution Probe

Evidence References:

Exhibit E1
Exhibit R1, Tab 1, Schedule 5.1
Exhibit R1, Tab 6, Schedules 4
Exhibit R1, Tab 6, Schedules 16

5.2 Is the applicant's forecast of debt reasonable?

Complete Settlement in conjunction with Issue 5.1

<u>6 Load Forecast</u>

6.1 Is the applicant's load forecast acceptable?

No Settlement

<u>7 Cost Allocation and Rate Design</u>

7.1 Did the applicant apply the Board's cost allocation methodology correctly?

Complete Settlement

Parties agree that THESL has correctly applied the Board's cost allocation methodology.

The following parties agree with the settlement of this issue: Consumers Council, Energy Probe, Schools, VECC, and THESL.

The following parties take no position on this issue: Pollution Probe

Evidence References:
Exhibit L1
Exhibit R1, Tab 1, Schedule 7.2
Exhibit R1, Tab 1, Schedule 7.8
Exhibit R1, Tab 1, Schedule 7.10
Exhibit R1, Tab 1, Schedule 7.11
Exhibit R1, Tab 6, Schedule 28

7.2 Are the proposed revenue to cost ratios reasonable?

No Settlement

7.3 Are the Fixed Monthly Charges reasonable?

No Settlement

7.4 Are the loss adjustment factors reasonable?

No Settlement

8 CDM

8.1 Is it appropriate to provide funding for the third tranche residential load control programme as proposed by the applicant, given that the applicant is also seeking funding from the OPA for a residential load control program?

No Settlement

8.2 Is it appropriate to provide incremental funding for governance of all existing CDM programmes as proposed by the applicant?

No Settlement

9 Smart Meters

9.1 Are the proposed costs for smart meters appropriate?

No Settlement

9.2 Is the proposed method of recovery of smart meter costs sought in the application appropriate?

No Settlement

10 Deferral and Variance Accounts

10.1 Is the proposal for the continuation of existing variance and deferral accounts appropriate?

Preamble: the OEB's Accounting Procedures Handbook (APH) identifies a series of deferral and variance accounts which utilities are permitted to use when recording qualified costs and revenues. The agreement set out below does not alter any permissions granted in the APH nor determine the validity of any existing deferral or variance account.

Narrowing of the issue:

The parties accept THESL's proposal for the continuation of existing variance and deferral accounts, as set out in the APH. THESL's proposals to continue variance account treatment for distribution losses ($RSVA_{Power}$), and to discontinue the use of the smart meter deferral accounts (1555, 1556) remain unsettled.

The following parties agree with this narrowing of the issue: Consumers Council, Energy Probe, Schools, VECC, and THESL.

The following parties do not agree with this narrowing of the issue: Pollution Probe. Pollution Probe objects to the continuation of variance account treatment for distribution losses, and otherwise takes no position with respect to other variance and deferral accounts.

Evidence References:
Exhibit J1, Tab 1, Schedule 2
Exhibit J1, Tab 2, Schedule 8
Exhibit J1, Tab 2, Schedule 9
Exhibit R1, Tab 1, Schedule 10.3
Exhibit R1, Tab 1, Schedule 10.3 Appendix C
Exhibit R1, Tab 1, Schedule 10.6

10.2 Is the proposal for the establishment of any new variance accounts appropriate?

No Settlement

10.3 Is the proposal for the amounts and disposition of Toronto Hydro's existing deferral and variance accounts appropriate?

No Settlement

10.4 Should there be a variance account for capital expenditures within the test period?

No Settlement

11 Rate Implementation

11.1 Is the proposal for 2009 and 2010 rates justified?

No Settlement

11.2 Is the proposal for rate implementation appropriate?

No Settlement