RP-2004-0188

HYDRO ONE

Ontario Energy Board
2006 Electricity Distribution
Rate Handbook

Argument-in-Chief Respecting Draft 2
Issued on January 10, 2005

February 14, 2005

Executive Summary - Comments on Key Areas of Concern for Hydro One

Hydro One has broad concerns about five main areas of the draft Handbook and will address these issues first prior to submitting more detailed comments on specific chapters.

The five main areas of concern are:

1. The level of detail prescribed for rate applications
2. The rate mitigation approaches proposed
3. The intended uses of benchmarking (Comparators and Cohorts)
4. The allocation of tax savings on disallowed expenses
5. The establishment of an appropriate equity return.

- **Level of Detailed Information Provided**

  Hydro One has identified a number of areas in the EDR Handbook where the level of detailed information to be provided is excessive. This results in high administrative costs for processing the application. In Hydro One's view, a reduction in the level of detail specified would not negatively impact the ability of the OEB or intervenors to fulfil due process, in regards to evaluating utility cost effectiveness or efficiency. This issue is discussed further in the Chapter 4 and Chapter 6 comments below.

- **Rate Mitigation Approaches**

  Certain intervenors believe that the cost allocation and rate design process for electricity distribution rates should include consideration of the full bill impact related to changes in electricity distribution rates and all other pass-through charges including the commodity price of electricity. Hydro One, and many other electricity distributors, believe that the electricity distribution businesses should not be required to delay recovery of costs, nor should they structure their rates to shield customers from price increases associated with the other pass-through charges including commodity. Hydro One engaged an expert in rate mitigation to review practices in other jurisdictions related to this issue. The review indicated that this was not a practice applied by regulators in other jurisdictions and the expert consultant developed and delivered written and oral testimony regarding these findings. This testimony was supported by the Coalition of Large Distributors. More detailed comments are provided in the Chapter 13 section below.

- **Use of Benchmarking**

  One of the working teams (Comparators & Cohorts Team) was charged with exploring and recommending the extent to which benchmarking should be applied in the rate setting process. The OEB staff retained an expert to review how benchmarking could be used in the 2006 rate setting process. Hydro One was

concerned that a misapplication of benchmarking could have both near-term and long-term consequences on the level of routine information the company would need to provide and the level of scrutiny which would be applied to the performance and cost information provided by utilities. Given the near-term and long-term financial and reputation risks associated with a misapplication of the discipline of benchmarking, Hydro One engaged an expert consultant in this area. This will ensure that the OEB and intervenors are fully informed of global practices in this area and that they are also informed of the related complexities of managing data quality and the methodologies that should be applied. Hydro One's testimony in this area was also supported by the Coalition of Large Distributors. The OEB staff's expert stated that benchmarking should not be applied to Hydro One. Both experts agreed that any comparison of data between utilities at this time should only be used as a screening tool. Considerable improvements in data consistency and accuracy will be required prior to any further use of the data.
Further comments are provided in the Chapter 13 section below.

- **Allocation of Tax Savings on Disallowed Expenses**

Some intervenor groups have argued that tax savings associated with disallowed utility expenses should also benefit utility customers, on the premise that allowing this benefit to flow to shareholders will result in delays in paying down Ontario Hydro's stranded debt. Hydro One worked with another distributor coalition, the Coalition of Issue Three Distributors (CITD) which was formed to efficiently deal with this specific EDR Handbook issue. The CITD engaged an expert regulatory consultant to study practices and principles applied in North America in this regard. The study found that when utility costs are disallowed this cost burden falls on the shareholder and any related tax savings should therefore accrue to the shareholder. Hydro One provides further comments in the Chapter 7 section below.

- **Establishment of an Appropriate Equity Return**

The EDR Handbook provides two alternatives associated with the maximum allowed return on equity. One alternative is based on using the most current data available at the time the OEB releases its 2006 EDR decision. The other alternative establishes the allowed return on equity for 2006 using the most current data prior to setting of rates. However, if there are changes to the Bank of Canada's 10- and 30-year Bond rates, the Board will issue a new return on equity annually. This alternative proposes to use the December forecast prior to the rate year to establish the maximum allowed return on equity.

Hydro One recommends the second alternative. The allowed return on equity should always be based upon the latest financial market information available relevant to the test year for the established rates. This methodology would be acceptable to Hydro One on an interim basis, subject to a full cost of capital review as part of the 2008 rate proceedings. Further comments are provided in the Chapter 5 section below.

General Comments on the Draft 2006 EDR Handbook

The Board has invited all participants in the RP-2004-0188 proceeding to file written submissions with the Board on issues relating to the rate handbook following the structure outlined in Procedure Order No. 4. Per this order, Hydro One Distribution (Hydro One) has structured its comments by chapter and section of the second draft of the handbook. Where a submission has been made by a coalition of which Hydro One is a member, Hydro One has noted support for the coalition's position. Where necessary, additional comments have been provided for circumstances unique to Hydro One.

Chapter 1: Introduction to the 2006 Handbook

Section 1.1 Application Components

This section states that an application for rates in 2006 must consist of three parts:

- The description of the application
- The completed 2006 EDR model
- Supporting schedules

Hydro One recommends this section be amended to separately describe what will be required for those utilities following a historical year approach versus those following a forward test year approach.

Hydro One Suggested Wording

This section states that an application for rates in 2006 must consist of the following:

For those utilities following a historical year approach:

- The description of the application
- The completed 2006 EDR model
- Supporting schedules

Potential adjustments to the 2004 historical year actuals are described in Chapter 3.

For those utilities following a forward test year approach:

- The description of the application
- Full written evidence, studies and supporting schedules for the 2005 bridge year and 2006 test year
- Supporting schedules for the 2002, 2003 and 2004 historical years

Chapter 2: Description of the Application

Hydro One has no comments with respect to Chapter 2.

Chapter 3 : Test Year and Adjustments

General Comments on LV Charges

To assist the Board in implementing on-going LV charges from Hydro One to Embedded LDCs the following proposal is being made. Ms. Lea raised this issue at the conclusion of the hearing on February 4, 2005 (Vol. 11, TR 886 – 891) and asked for assistance to the Board in whether the forward-looking elements should be included in the handbook.

Background on LV rates

The currently approved LV rates, established on the basis of 1999 costs, have not been implemented as a result of Bill 210. The bulk of the LV charges come from the Shared LV line charge that is applied to 1999 billing parameters. The LV charges that were approved in RP-2000-0023 were determined on the basis of a cost allocation study. The use of 1999 billing parameters was approved by the OEB as an interim measure in the interest of implementing unbundled electricity distribution rates for market opening. It is expected that the next generation of LV rates to be submitted by Hydro One to the OEB for review and approval will be based on more recent costs and charges and will be on going forward (i.e. 2006) consumption levels of Embedded customers.

It is expected that Embedded LDCs will have to submit their application for 2006 rates in the Summer of 2005, that is before Hydro One submits its own application for 2006 rates in the Fall of 2005. Hydro One's application will include new evidence on the cost of LV service and rates that will become effective in May 2006. Therefore, Embedded LDCs will not have the newly approved LV rates by the time they file their submissions to the OEB in the Summer of 2005. The issue then is what needs to be done to assist the Embedded LDCs in completing their obligations under the revised EDR Handbook requirements in respect of LV charges.

Hydro One Proposal

Hydro One proposes that Embedded LDCs use the current, approved LV rates, applied to their forecast 2006 consumption levels in their rate applications. Under this proposal, Hydro One would proceed as planned with its Distribution rate application in the fall of 2005 and Embedded LDCs would estimate their LV charges for 2006 based on the currently approved LV rates and would apply these rates to the LDCs' 2006 consumption estimates. Any variance that would arise as a result of the difference between Hydro One's new LV charges that come into effect in 2006 and the current LV rates applied as proposed above would be recorded in the RSVA Connection account and would be cleared in a future OEB proceeding.

The approach under this proposal would allow Embedded LDCs to proceed in a timely fashion with their 2006 rate applications. Use of this proposal as a starting point for the implementation of LV charges is premised on the fact that a formal cost allocation study was prepared and there was significant debate on cost allocation with respect to the LV rates in the RP 2000-0023 proceeding. Given that the going forward distribution rates for

Embedded LDCs in 2006 will not be cost based, the use of existing approved rates is not out of context in the general process of redressing the recovery of costs from the appropriate entities. This approach, although not perfect, at least moves all LDCs in the right direction of implementing on-going LV charges. It was generally argued in the Regulatory Assets Review hearing that recovery of the LV costs should be implemented in as timely a manner as possible to avoid further accumulation of deferred charges and related interest to be recovered in future rates.

Other Chapter 3 Recommendations

Page	Section	Preferred Alternative	Reasoning
16	3.0 Test Year and Adjustments	Alternative 2	2006 material event disclosure should only be applicable to applicants filing on a future test year basis.
18	3.2 Test Year Adjustments (Table)	Alternative 2	2006 in-service transformer stations should not be included as a Tier 1 rate base adjustment. Applicants who wish to include 2006 in-service additions should file on a future test year basis.
18	3.2 Test Year Adjustments (Body)	Alternative 1	If the Board selects Alternative 1, then the mid-year rule should apply for consistency with applicants filing on a future test year basis.
21	3.2 Test Year Adjustments Tier 1 Adjustments: Rate Base 5) Non-routine/unusual adjustment	Alternative 2	Exclude as per the note to 3.2 (Table) above.
23	3.2 Test Year Adjustments Option 2: Tier 2 Adjustments	Alternative 2	Additional hardship funding requests should be included if they are needed to address a material degradation of a distribution system.
26	3.2 Test Year Adjustments Schedule 3-1: Tier 1 Adjustments 2. Other Standard Distribution Expense and Rate Base Adjustments	Alternative 2	Exclude as per the note to 3.2 (Table) above.
28/ 29	3.2 Test Year Adjustments Schedule 3-3: Tier 2 Adjustments 3.	Alternative 2	Tier 2 adjustments must pass a higher level of scrutiny so the additional analysis would assist the stakeholders in better assessing the need.

Chapter 4: Rate Base

Section 4.1 Definition of Rate Base

The applicant is required to file information on its 2004 total assets, broken down into distribution and non-distribution segments.

Alternative 1: *The level of detail in this filing will be as outlined in Schedule 4-1, Appendix B, and in the 2006 EDR Model*

Alternative 2: *The level of detail in this filing will be… [as proposed by a party supporting this alternative in argument].*

Hydro One Recommendation

Hydro One recommends Alternative 1. The aggregate level of USofA detail as provided in Schedule 4-1, page 36 provides sufficient detail respecting historical capital expenditures to assess spending levels, their prudence and need. Providing information at the USofA account level will not provide any additional value for the following reasons:

- The parties to this proceeding have already identified areas where additional filing detail is required. For example, Schedule 4-1 requires a more detailed breakdown of IT related capital expenditures and Chapter 6 outlines areas where additional detail is required for distribution expenditures including insurance, information technology and charitable contributions.

- Any meaningful comparison of applicant to applicant, or year-over-year applicant comparisons can only be made at a higher level of expenditure allocation due to the data inconsistencies noted in the first bullet. Applicants will have made changes to how expenditures were recorded at the detailed USofA accounting level as clarification and experience has been gained since their introduction.

- USofA accounting is new to the electricity distributors in Ontario. As discovered in the recent Regulatory Asset Review Proceeding, RP-2004-0117/118/0100/0069/0064, there were consistency issues as noted by the Board amongst the applicants even among a limited number of USoA accounts. To require filing of information at a detailed USofA account level will complicate and confuse the process and provide little if anything of substance other than an organization of likely non-comparable data.

The marginal if any added benefits associated with preparing applications at the detailed USofA account level does not justify the additional effort and cost that an applicant would have to incur to provide other than the aggregated data shown at Schedule 4-1. Ms. Lea expressed concern with the level of detail being requested in her closing testimony. (Vol. 11, TR 924-935). These same arguments also apply to the filing of distribution expenses in Chapter 6 of the draft Handbook.

Section 4.3 Capital Investments
4.3.1 Non-IT-related

This section of the handbook lists three alternatives for determining materiality thresholds for non-IT related capital investments. Under Alternatives' 1 and 3 the applicant must use the lower of the two thresholds (Fixed $ Threshold and % of Net

Fixed Assets) to determine their materiality threshold for providing additional detailed capital expenditure support. Alternative 2 simply uses a per cent of net fixed assets as the materiality determinant.

Hydro One Recommendation

Hydro One recommends Alternative 2, 0.2 percentage of net fixed assets as defined for rate base as the materiality criteria for non-IT related capital expenditure materiality. A percentage materiality level will better identify the level and type of capital expenditures that will have a rate impacts than a stated fixed dollar level.

For example, by applying the 0.2% of rate base criteria to Hydro One would result in an examination of individual project expenditures each of which would add less than 0.1 per cent to the test year revenue requirement. The $500 thousand fixed amount would equate to a 0.016 per cent of rate base.

Clearly, in Hydro One's case, providing project costing and support detail at any level below the 0.2% of rate base would lead to a detailed filing of information that would detract hearing participants from adequately focusing on the key initiatives in the filing and would involve the Board in micro-managing the applicant. Ms. Lea addresses the establishment of an effective level of detail at the conclusion of the hearing. (Volume 11, TR 928).

Section 4.4 Interest on Deferral Accounts and Construction Work in Progress (CWIP)

Hydro One Argument Re: Section 4.4
Deferral Accounts

At page 34, the draft Handbook presents three interest rate alternatives for deferral account balances:

Alternative 1: *…the embedded cost of debt (GAPP)***.**

Alternative 2: *…some form of short-term debt rate.*

Alternative 3: *…deemed debt rate (5- to 10-year rate).*

Hydro One recommends the adoption of Alternative 1 as the use of a utility's embedded cost of debt provides the proper assignment of carrying costs to the deferral account balances as actually experienced by an applicant.

As a general principle, for deferral accounts of a longer-term nature, which the Board as recently as its RP-2004-0117/0118/0100/0069/0064 Decision defined as "generally more than one year" (Page 25, Paragraph 3.0.17), a longer-term interest rate should apply.

In this hearing the Board recognized the period of time from the incurring of costs to full recovery would stretch over several years and allowed the use of a long-term debt rate. The Board ruled that with the exception of Hydro One, the deemed long-term debt rate in the existing Handbook should apply in the case of Toronto Hydro, Enersource Mississauga and London Hydro. Hydro One was to use its last approved long-term debt rate. (Page 18, 2.0.29)

As noted at Page 3 of Exhibit B.7, for deferral accounts that will be recovered on an annual basis, Hydro One would support the use of a shorter-term debt rate. For such accounts, Hydro One would support the methodology used by the Board to determine the 5.75 per cent approved for Conservation and Demand Management (CDM) and the Ontario Energy Board's costs. (Prime plus XXX Basis Points)

Comments on the VECC Proposal Respecting Deferral Accounts

Hydro One recommends the Board's outright rejection of the VECC proposal. Not only is it contrary to the Board's recent Regulatory Asset Decision and its recent gas utility Decisions it is also not reflective of regulatory practices in other Canadian jurisdictions.

When asked to provide an example of a regulator that imposed such a rate (Prime less 175 basis points) for deferral accounts VECC's witness, Mr. Matwichuk, was unable to readily provide an actual example and undertook to do so. Undertaking E.3.1 that was filed on February 9, 2005 confirms that there is no particular instance that Mr. Matwichuk is aware of where a regulatory agency in Canada has set a rate of prime less 175 basis points for the carrying cost associated with deferral accounts.

In fact, Mr. Matwichuk admits that his proposal is not an attempt to suggest that the actual rate selected by the Board should be hard and fast as his evidence suggests. (Volume 3, TR 140)

Hydro One therefore submits that the Board should disregard VECC's submitted framework.

Hydro One Argument Re: Section 4.4
Construction Work-in-Progress (CWIP)

At page 34, the draft Handbook also presents two interest rate alternatives for CWIP account balances:

Alternative 1: *…the embedded cost of debt (GAPP).*

Alternative 2: *…some form of short-term debt rate.*

Hydro One Recommendation

For applying interest to CWIP account balances Hydro One recommends the adoption of Alternative 1. As the CLD notes at Page 2 of Exhibit B.7, the capitalization rate used by a utility should reflect the actual financing costs being incurred to finance the asset. The utility's embedded cost of debt best reflects a matching of the way in which the assets under construction will be permanently financed. Hydro One notes that VECC also supports the use of Alternative 1. (Exhibit B.1, Page 17)

Other Chapter 4 Recommendations

Page	Section	Preferred Alternative	Reasoning
30/31	4.1 Definition of Rate Base	Alternative 1	For those utilities filing on an historical year basis, 2004 year-end is the appropriate measurement period. 2006 mid-year is appropriate for those utilities filing on a future year basis.
34	4.5 Capitalization Policy	Alternative 1	Capitalization policy of the applicant need not be filed. A description of the policy is all that needs to be filed with the application.

<u>Chapter 5: Cost of Capital</u>

Section 5.1 Maximum Return on Equity

Two alternatives are presented in Chapter 5 for how the Board might determine the maximum equity return for 2006.

Alternative 1: *The Board will determine the maximum allowed return on equity for 2006 using the most current data available at the time it releases its 2006 EDR decision.*

Alternative 2: *If there are changes to the Bank of Canada's 10- and 30-year Bond rates, the Board will issue a new return on equity annually. The Board will use the December forecast prior to the rate year to establish the maximum allowed return on equity.*

Given the complexity of changing the rate schedules for all distributors prior to implementing rates in May 2006, distributors will track the difference between the 2006 Handbook-issued rate, and the Board's updated maximum return on equity, in a variance account.

Hydro One Recommendation

Hydro One recommends Alternative 2. The allowed return on equity should always be based upon the latest financial market information available relevant to the test year for the established rates. By reflecting the latest Bank of Canada 10- and 30-year Bond rates by way of an annual update, the Board will be assured that the rates set for 2006 reflect current financial market conditions and minimize market risk. Under this alternative, in periods of declining rates the ratepayer benefits while in periods of rising rates the utility benefits.

Applicants who are unable to implement new rates reflecting this annual adjustment in a timely manner, should track differences between their rates in place and the updated forecast in a variance account. This methodology would be acceptable to Hydro One on an interim basis, subject to a full cost of capital review as part of the 2008 rate proceedings.

Alternative 1 omits a key part of Dr. Cannon's formula approach from his 1998 discussion paper, that being the annual update to return on equity resulting from a change in the forecast rates for Bank of Canada 10- and 30- year bonds. (Page 33)

Other Chapter 5 Recommendations

Page	Section	Preferred Alternative	Reasoning
41	5.2 Debt Rate Weighted average debt rate	Alternative 2	Third party debt should always be reflected in the capital structure at the actual debt rate at the time of issuance whether higher or lower than the deemed rate and whether obtained from the markets by the utility or through the parent holding company. Affiliate debt should be reflected at the lower of the deemed and actual rate.
43/44	5.4 Working Capital Allowance 5.4.1 Introduction	Alternative 2	The cost of power reflected in the working capital calculation should be based upon the latest cost of power forecast available from the IMO or other approved authority to provide a better matching of costs and rates required.
44	5.4 Working Capital Allowance 5.4.1 Introduction	Alternative 1	The sum of the working capital accounts is to be reduced by the dollar value of customer security deposits.
45	Schedule 5.1	Alternative 2	Schedule 5.1 should be completed following Hydro One's recommendations for section 5.2 above. In addition, historical debt from the first-generation PBR Distribution Rates Handbook for historical debt for the period 2000 to 2004 should be used to complete this schedule as those were the rates that underlie the rates in place during this time period.

Chapter 6: Distribution Expense

Level of Account Detail

The applicant is required to file information on its 2004 total assets, broken down into distribution and non-distribution segments.

Alternative 1: *Distribution expenses data are to be entered on* ***Tab_Trial Balance of the 2006 EDR Model****. It will be displayed and totalled on the* ***Distribution Expense sheet****.*

Alternative 2: *Distribution expense data are to be entered on* ***Tab_Grouped Trial Balance of the 2006 EDR Model,*** *in aggregated groupings.* ***(tentative)***

Hydro One Recommendation

Hydro One recommends the adoption of Alternative 2. The aggregate level of USofA detail as provided in the Tab_ Grouped Trial Balance of the 2006 EDR Model provides sufficient detail respecting Operating, Maintenance and Administrative expenses for the Board to adequately access spending levels, their prudence and need at a higher functional level. Please refer to our discussion respecting Section 4.1, rate base as the same arguments apply to the level of detailed required for distribution expenses as was the case for capital expenditures. If anything there will be even more inconsistency from LDC to LDC in terms of the booking of amounts to the applicable OM&A detailed USofA accounts.

Other Chapter 6 Recommendations

Page	Section	Preferred Alternative	Reasoning
49	6.2.1 Insurance Expense Recoverability of Self-insurance Costs	Alternative 2	Any change in reserve(s) for self-insurance should not be included in the 2006 revenue requirement. The use of 2004 actual claims experience negates the need to forecast the level and appropriateness of any reserve amount for self-insurance.
51/52	6.2.4 Charitable Contributions Minimum Filing Requirements	Alternative 3	An applicant should be allowed full recovery of charitable contribution expenses in their 2006 revenue requirement to the extent these donations benefit the communities they serve.
52	6.2.4 Meals/travel and business entertainment expenses	Alternative 2	There is no need for an applicant to file written policies respecting employee expenses as long as the applicant provides an adequate description of the practices in place.
54	6.2.5 Employee Total Compensation 2) Minimum Filing Requirements Guidelines for applicants with fewer than three employees	Alternative 1	There should be no need to file employee compensation data where there are less than 3 employees within the applicant.
55	6.2.5 Employee Total	Alternative 2	An applicant not subject to mandatory disclosure laws need not file total compensation for each distributor employee earning

	Compensation 2) Minimum Filing Requirements Required Information Disclosure Additional Filing Requirements		more than $100,000 per annum.
55	6.2.5 Employee Total Compensation 3) Incentive Plans	Alternative 1	Performance incentives must be of substantial benefit to the ratepayers to be included in determining 2006 revenue requirements.
58	6.2.7 Distribution Expenses Paid to Affiliates Proposed Additional Filing Guidelines	Alternative 2	No additional filing requirements are required other than those outlined under the Minimum Filing Requirements section on pages 57 and 58.
58	6.2.7 Distribution Expenses Paid to Affiliates Proposed Additional Filing Guidelines Additional Wording	Alternative 2	No additional wording is required as per note above.

Chapter 7: Taxes/PILS

7.1.1 General Principles Underlying the 2006 Tax Calculations
True-Up of 2006 Actual Taxes Paid to Taxes Recovered in Rates

Two alternatives have been presented with respect to the necessity to a true-up for actual taxes paid.

Alternative 1: *Partial True-Up, inclusive of tax rate/tax law/assessing policy changes and reassessments*

Alternative 2: *100% Pass-Through/True-Up*

Hydro One Recommendation

Hydro One supports the adoption of Alternative 1. A true-up should only take place for government driven factors such as a change in corporate tax rates or corporate tax policy at the federal or provincial level.

Each distributor should establish a 2006 PILs/taxes variance account to capture the tax impact of the following differences:

- any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model

- any difference that results from a change in, or a disclosure of, a new assessing or administrative policy of the Federal or Provincial tax authorities, if the Board has declared that such new or modified assessing or administrative policy is a change of general application that should be treated as if it were a change in tax rules

- any difference in 2006 PILs that results from a tax re-assessment

    - received by the distributor after its 2006 rate application is filed, and before May 1, 2007

    - relating to any tax year ending prior to May 1, 2006

These types of changes cannot be forecast accurately and are beyond the control of the applicant. Hydro One supports the evidence filed by Toronto Hydro at Exhibit B.2.

Hydro One cannot support the 100% Pass-Through/True-up suggested by Alternative 2. Ratepayers should not be required to pay additional taxes associated with an increase in an applicant's net income resulting from increased volume sales, or prudent expense management. In effect, they would pay taxes on this increase twice if a 100% true-up were in place. Historically, the gas utilities have borne the risk of forecast inaccuracies and the electricity utilities should be treated in the same manner to ensure a level playing field continues to exist in Ontario. This option also scored low in terms of fairness as noted by Mr. Erling of KPMG at TR. 155.

7.1.1 General Principles Underlying the 2006 Tax Calculations
7.1.1.2 Non-recoverable and Disallowed Expenses

Hydro One supports the evidence filed by the Coalition of Issue Three Distributors (CITD) as Exhibit B.9 and their Argument-in-Chief with respect to these two issues.

It is Hydro One's position that the tax benefits associated with any disallowed Board expenditures should go to the benefit of the applicant's shareholder. The costs associated with disallowed expenditures are borne by the shareholder and under the established principle of 'benefits follow costs" any related tax savings should therefore accrue to the shareholder. Costs associated with the disallowed expenditures are not reflected in the rates of the distributor, so the ratepayers should not be entitled to any tax savings associated with these expenditures. To do so would lower the allowed return available to the shareholder approved by the Board and would violate established regulatory principles.

The underlying assumption with respect to disallowed expenses appears to be that an applicant would continue to make these expenditures even with the full knowledge that no recovery in rates will be allowed. However, in our view, it is very unlikely that any prudently managed organizations would continue to make disallowed expenditures unless there is a justifiable business rationale for doing so (e.g. non-recoverable charitable donations or non-recoverable operational expenses). Therefore, one would generally expect that non-recoverable expenditures would not be incurred by the utility. If the Board, in addition to disallowing the expense also determined that the associated tax savings are to be passed through to ratepayers, then the ratepayers will be benefiting from a tax reduction that would not arise since in all likelihood the disallowed expense would not be incurred by the utility. In fact, the actual cost to the utility could exceed the cost of the disallowed expenditure if the amount proved to be non-deductible for tax purposes since rates would also have been reduced by the associated tax benefit. This is clearly an inequitable result. Therefore, it is Hydro One's position that the tax benefits associated with any disallowed Board expenditures should go to the benefit of the applicant's shareholder. We agree with the CITD position that once the OEB has approved the allowed return on equity, that the utility should then be free to spend the return in any manner that it deems prudent and within the requirements of good corporate governance

Section 7.1.2.5 Loss carry-forwards

According to this section of the draft Handbook, distributors must include any available loss carry-forwards in their calculation of 2006 income taxes. This is yet another attempt to reward the ratepayers through an income tax reduction for an expense for which they have no entitlement

The Board approved a revenue requirement for the utility including an allowance for applicable income taxes and their rates will have been set based upon this level. The fact that a utility incurred a loss whether because a utility's revenue was less than allowed or their expenses were greater than approved is irrelevant to the 2006 tax calculation for utility purposes. The ratepayer has not contributed to this loss and therefore is not entitled to share in any associated future tax savings from the loss carry-forward.

Hydro One Recommendation

The derivation of 2006 PILs should not include any loss carry-forward amounts.

Section 7.1.2.7 Amortization of tangible assets and capital cost allowance (CCA)

Hydro One is concerned by the apparent inconsistency with the information base proposed for calculating 2006 PILs versus all other revenue requirement components for 2006 for utilities utilizing a historical year filing. At page 78, the current Handbook wording requires that the applicants include in their CCA deductions a forecast of 2005 and 2006 capital expenditures using 2004 actual additions adjusted for any Tier 1 and Tier 2 adjustments. This would result in the PILs calculation being based on a higher rate base amount than that of the equity return and book depreciation. This would have the effect of reducing the shareholders allowed equity return since CCA deductions would be based upon a fixed asset base higher than what the equity return is determined on. This is equivalent to allowing ratepayers to receive the tax benefits attributable to disallowed expenses. In this case, CCA deductions would be based upon a fixed asset base higher than what the equity return is determined on. For similar reasons, any tax savings associated with purchased goodwill and other intangible assets should not be included in the 2006 CCA calculation.

Hydro One Recommendation

For utilities that utilize a historical test year filing, the derivation of 2006 PILs should not include an escalation of fixed asset base for 2005 and 2006. The base should be 2004 plus any applicable Tier 1 and Tier 2 adjustments. The 2001 FMV bump and the cost of purchased goodwill and other intangible assets should be excluded for utilities that file on either a historical or future test year basis.

Other Chapter 7 Recommendations

Page	Section	Preferred Alternative	Reasoning
72	7.1.2.2 Non-recoverable and disallowed expenses	Alternative 3	100% of tax savings associated with Board disallowed expenses should be to the shareholder's benefit.
73	7.1.2.2 Non-recoverable and disallowed expenses Eligible Capital Expenses (ECE)	Alternative 3	100% of tax savings associated with the October 1, 2001 fair market value adjustment should be to the shareholder's benefit.
73/74	7.1.2.2 Non-recoverable and disallowed expenses 2) ECE with respect to disallowed expense	Alternative 3	100% of tax savings associated with purchased goodwill and other intangible assets should be to the shareholder's benefit.
74	7.1.2.2 Non-recoverable and disallowed expenses Charitable Donations	Alternative 3	100% of tax savings associated with disallowed charitable donations should be to the shareholder's benefit.
75/76	7.1.2.4 Sharing of tax exemptions	Support iii)	Hydro One does not support the wording in Alternative to (iii) that states that the federal LCT tax exemption should not be pro-rated between distribution and other activities.
77	7.1.2.7 Amortization of tangible assets and capital cost allowance (CCA). Deduction:	Alternative 2	The 2005 opening balance must not include the 2001 Fair Market Value (FMV) Bump.
78/79	7.1.2.8 Interest deduction	Alternative 1	Interest deducted in computing the 2006 tax calculation should be the same as that allowed for recovery in 2006

			rates, as established in Chapter 5 of the Handbook. Note: Alternative 1 Heading should be changed to read "Recoverable Interest Expense."

Chapter 8: Revenue Requirement

Hydro One has no comments with respect to Chapter 8.

Chapter 9: Cost Allocation

Hydro One has no comments with respect to Chapter 9.

Chapter 10: Rates and Charges

Section 10.8 Low Voltage Charges
Comments on the implementation of On-going LV Charges are provided in Chapter 3 above.

Other Chapter 10 Recommendations

Page	Section	Preferred Alternative	Reasoning
105	10.5 Update of Loss Adjustments Factors Reflecting System Losses Including Unaccounted-for Energy	Alternative 2	
106	Distributed Generation	Alternative 2(b)	

Chapter 11: Specific Service Charges

General Comments on Standby Charges

Ms. Lea, in her submission on February 4, 2005, (Vol. 11, TR 983) raises the concern that standby charges could be in conflict with the government policy with respect to net-metering. Hydro One is of the view that there may be circumstances under which the application of standby charges for customers with load displacement generation facilities subject to net-metering is appropriate to properly reflect cost causality and the application of the "user pay" principle.

Ms. Lea (Vol 11, TR 984) refers to the Hydro One transmission rate case, RP-1999-0044, and specifically the Board's ruling on paragraph 3.4.11. Ms. Lea asks the question if this paragraph is consistent with the provisions of the draft Handbook for standby charges. The paragraph referred to in RP-1999-0044 deals with the issue of fixed charges for recovery of transmission related costs from customers. It does not deal with standby charges. Fixed charges were rejected for transmission, but were accepted by the Board for recovery of Distribution charges. Hydro One sees no conflict between the Board decision in RP-1999-0044 and the 2006 EDR Handbook provision to allow for the application of standby charges.

Ms. Lea also asks (Vol 11, TR 985) if the 2006 EDR process is the best place to determine standby charges, or if this issue should be deferred to the upcoming cost allocation and rate design process. Hydro One is of the opinion that the issue of standby charges should be dealt with as part of the 2006 EDR process and not wait until cost allocation and rate design issues are dealt with. Standby charges are an acceptable mechanism to recover the costs that load displacement generators impose on distributors and ensure that these costs are properly recovered from the customers that caused these costs to be incurred. The methodologies recommended in the Handbook to establish standby charges are sound methodologies that are being applied in other jurisdictions.

Comments on Charges for Power Quality Inspections

Ms. Lea asks (Vol 11, TR 996) if the handbook should include a standard charge for power quality inspections. Hydro One suggests there should be such a charge.

Similar to the meter dispute charge, a standard charge should be applied for power quality inspections only when the source of the complaint is within the customer's plant as follows:

Basic Service Call (initial assessment)	$30
Engineering Investigation (detailed investigation)	Time & Materials

Chapter 12: Other Regulated Charges

Hydro One has no comments with respect to Chapter 12.

Chapter 13: Mitigation

General Comments on Section 13.2 Mitigation Methodologies

The matter of rate mitigation is important to ensure that customers are afforded a means by which substantial rate increases can be implemented without causing undue hardship to customers. At the same time the distribution utility needs to ensure that the mitigation process implemented to manage rate impacts does not adversely impact its financial well being. Therein lies the quandary – how best to manage the balance between customer satisfaction and utility satisfaction – i.e. how can one achieve a win-win situation.

The starting point of the rate process is the establishment of cost based revenue requirement. Once that matter has been decided through a public process, the utility proceeds to allocate costs and design rates. The assumption is that the arrived at rates should recover the established revenue requirement. Logic therefore dictates that the established revenue requirement should not be altered (reduced) just because the resulting rate impacts are significant.

The starting premise is that rates are based on the best attempts to represent cost causality such that customers pay their fair share of costs that the utility has incurred on their behalf. Therefore if utility costs increase for a variety of reasons that are found to be prudent, or that have been imposed by government directives or policy changes, then customers rates will generally increase and the expectation is that customers will pay more. Due to the fact that distribution rates were set on the basis of 1999 costs and load levels, it is expected that significant cross-subsidies exist in today's distribution rates and that the rates are not cost reflective for the most part. Consequently, adjustments to correct these shortcomings could result in significant rate increases to some customer classes.

Increases in 2006 distribution revenue requirements are anticipated and therefore, the first attempt at rate design will no doubt identify that some customers will be impacted more than others. Further iterative attempts can then be made to redress the balance by altering the "fixed" and "variable" rates that will provide some degree of mitigation. The net effect of such consideration can be that rates depart further from reflecting cost causality and a greater degree of cross-subsidization is introduced. This is a well-established method used throughout the industry but it requires acceptance by the regulatory bodies and the governments that resulting rates will not be cost reflective. Consequently any move towards the goal of cost based rates is further delayed and if future rate increases are anticipated, as is the case post 2006, then appropriate rate adjustments may be delayed indefinitely since rate impacts will also be a concern post 2006.

It is obvious that some degree of re-adjustment is required to distribution rates to bring them in line with government policy. Furthermore, utilities have been investing in their infrastructure and incurring costs since the last cost of service review, which was a significant period of time prior to market opening. It must be acknowledged that costs have been incurred to implement policy changes such as market opening. Rates have been frozen by policy changes such as Bill 210. It also needs to be recognized that LDCs have not been responsible for all of the costs that they have incurred as a result of government policy changes. In this case LDCs should not be made to pay for the mitigation of these costs since these are largely outside their sphere of influence and control. Logic dictates that these costs should be passed through to customers unmitigated because ultimately electricity consumers benefit from the changes in government policy. Therefore rate mitigation should be done only to manage the impacts due to costs attributable to LDC activities. Such mitigation should not erode the return that the Board finds otherwise to be fair and reasonable.

In the same way the LDCs should not be responsible for costs resulting from commodity price changes since these lie outside the LDCs control. The Board has recognized this matter in its regulation of gas distribution utilities' rates in the province. Consequently rate impact mitigation should focus only on the distribution related cost changes.

Hydro One is also of the view that for 2006 distribution rate setting, rate harmonization should not be part and parcel of the same bundle of items that are included in the rate mitigation process. Hydro One is significantly impacted by the fact that it has 87 separate rate schedules for its Acquired LDCs that vary significantly in their charges and to include this within the bill impact mitigation would be unreasonable.

Other Chapter 13 Recommendations

Page	Section	Preferred Alternative	Reasoning
142	13.2 Rate Harmonization	Alternative 1	LDCs should be allowed to start harmonization plans as soon as feasible, since it may take many years to achieve full harmonization

Chapter 14: Comparators and Cohorts

Considering that Hydro One is significantly different from other LDCs in Ontario and will not logically fall within a cohort group, we agree and accept the view of Dr. Mark Lowry, Mr. Robert Camfield and OEB staff that Hydro One be excluded from the Comparators and Cohorts mechanism process. At the same time we have committed to a comprehensive full submission based, to the extent possible, on the draft Rate Handbook requirements and offer comments on that basis.

Before providing comments, Hydro One would like to summarize why it is significantly different from other LDCs. In Ontario, Hydro One Networks supplies electricity along with associated services to

* the highest number of retail customers (1,145,000),
* with the most number of circuit kilometers of line (119,000)
* of which 15,800 km are sub-transmission (mostly 44kV voltage).

Hydro One's service territory covers by orders of magnitude the largest service area of 650,000 square kilometers with wide exposure to all climatic events and geographical differences. Our customers are mostly in the rural density as well as seasonal cottage areas (average of 9 customers per km) that extend to every corner of the Province (excluding those areas serviced by Hydro One Remote Communities). Hydro One not only distributes approximately 28 TWh of energy to its retail customers but also transports about 16 TWh of energy to large Direct customers (over 5MW) and to 74 Embedded LDC's. Embedded LDC's are connected to Hydro One's sub-transmission system, distribution stations and/or distribution feeders.

Although we support Dr. Mark Lowry's suggestions in modifying Exhibit E 6.3 for C&C filing requirements for LDCs, and the theoretical approach to benchmarking, there needs to be consideration for information availability, integrity and efficiency. Like other distributors in Ontario, some of this information is not readily available for reporting at this time. Also, it is not clear whether the level of detail outlined strikes the right balance across all categories when comparing the incremental collection costs for the LDCs versus the related benefits. Furthermore, these suggestions are a starting point and further discussion and work is required. This includes developing clear definitions of requirements to ensure accurate and consistent data is reported by LDCs.

Given the time allowed at this point in the proceeding, there are serious questions as to how reliable the data could be. This is especially pertinent considering that the previous year's data, submitted in the PBR portion of the Board's RRR filing, lacked consistency and accuracy as already identified by the C&C Working Committee. The issue of data integrity became an issue also during the OEB review of Regulatory Assets for the four LDCs that were the subject of an Oral Proceeding. It is recognized that the OEB is looking for a screening tool to make their task manageable, however the Board must recognize that data integrity is of paramount importance, especially given the potential for improper interpretations in the regulatory arena.

While we support the theoretical process of benchmarking that the experts (Lowry and Camfield) have recommended, there needs to be only one source of data instead of two. The RRR data already exists and is filed on a quarterly and annual basis. LDCs provide ample data through the RRR submissions that the OEB staff can consider for the screening tool.

Chapter 15: Service Quality Regulation

This chapter is a successor to Chapter 7 of the first rate handbook and some changes in the wording have been made primarily to incorporate errata issues subsequent to the issuance of the first handbook. Hydro One has no comments with respect to Chapter 15.

Conservation and Demand Management

The expert testimonies of Mr. Goulding, Mr. Chernick, Mr. Gibbons and Mr. Heeney were unanimous in asserting that three elements must be put in place in order for utilities to deliver the desired results:

- recovery of costs associated with CDM activity;
- lost revenues resulting from reduced peak electricity demand and reduced energy consumption; and
- incentives tied to the behaviour the Board would like to see from the utilities, sufficient enough to encourage the shifting of scarce resources to CDM from other activities.

None of the experts agreed with the approach of requiring utilities to spend a minimum amount on CDM activity or with setting a fixed cap on spending. These witnesses seemed to be in agreement that a better approach is one in which utilities develop CDM programs appropriate to their utility and that below a certain level of funding there would be minimal up front review of that level of funding. Beyond that level of funding the Board might wish to have a more in depth up front review of the proposed programs to ensure that the programs are consistent with the CDM guidelines provided by the Board and that the level of planned spending is appropriate.

Recovery of Costs Associated with CDM Activity
Hydro One is in agreement with the expert witnesses that recovery of program expenditures and the costs of the associated administrative effort are a precondition for distributors to be able to undertake CDM activities. The preferred utility mechanism for cost recovery is one that collects revenue during the same period as costs are being incurred.

Lost Revenue Resulting from Reduced Sales
Hydro One is in agreement with the expert witnesses, that recovery of revenues lost due to the undertaking of CDM activities is necessary in order to protect the financial viability of the province's electric distributors and remove the disincentive for them to participate in CDM. Mr. Goulding, Mr. Chernick, Mr. Gibbons and Mr. Heeney agreed that while a retrospective lost revenue adjustment mechanism (LRAM) may be sufficient, a prospective LRAM has the benefit of reducing the size of the variance accounts that would be required and, unlike the retrospective LRAM, would not negatively impact the utility's cash flow. Hydro One believes that distributors should have the option of proposing a load forecast for rate setting purposes that incorporates energy and peak demand reductions associated with planned CDM activity. A variance account would be used to address LRAM effects that deviate from this forecast.

Hydro One agrees with the position put forward by Mr. Chernick, Mr. Gibbons and Mr. Heeney, that for at least the short term it is advisable to adopt an approach similar to that suggested by the RP-2004-0188 Conservation Working Group, whereby input assumptions for calculating revenues lost to CDM effort, and for which the utility will be compensated, are pre-approved by the Board. This provides utilities with an assured mechanism for assessing programs and for recouping lost revenues.

Hydro One agrees with evidence provided by Mr. Gibbons and Mr. Heeney that even in the longer term, adjustments to input assumptions should be done prospectively, not retroactively. We believe that, rather than requiring each utility to undertake an extensive audit and report on each of its programs, a review of only a small sample of similar programs should be necessary to verify and/or re-calibrate the relevant common input assumptions on a prospective basis. Only in those cases where a utility has a unique program, typically for a large commercial or industrial customer, should there be a need for utility-specific information.

Incentives to Shift Scarce Resources to CDM from Other Activities

Hydro One agrees with evidence submitted by all of the above parties, which recognizes the need for incentives to encourage utilities to assign their limited resources from more traditional utility operations to CDM activities.

Hydro One agrees with Mr. Chernick, Mr. Gibbons and Mr. Heeney that an approach consistent with that suggested by the RP-2004-0188 Conservation Working Group, in which input assumptions for calculating incentive payments are pre-approved by the Board, would provide utilities with the information they need to confidently assess and deliver CDM programs. Mr. Heeney provided a sample list of some pre-approved inputs in use in California, which might be appropriate as a starting point for developing pre-approved inputs for Ontario. This would be consistent with Mr. Goulding's desire to rely more on third party calculations than on the Board doing all of its own calculations. Hydro One agrees that employing such lists from California and/or other jurisdictions is an excellent starting point and that it would greatly facilitate the development of pre-approved inputs specific to Ontario. The Ontario Power Authority might reasonably provide some or all of these inputs once it is fully operational, but in the interim a Board sponsored/directed process would best establish and maintain a set of approved inputs for use by all distributors.

A utility side expenditure and a customer side expenditure that produce the same reduction in peak power or in energy required from the transmission system have the same value to the electricity system and as such, Hydro One believes should be eligible for the exact same incentive structure. In speaking about utility side CDM incentives, Mr. Goulding indicated that he was in agreement with Hydro One's submission in this regard and provided the following clarifying perspective, "… there may be incremental investments that we could make that would be solely focused on conservation and demand management that would occur on the utility side of the meter that we would otherwise not undertake without a particular incentive, because those investments would not go into rate base; or, under a traditional, sort of, rate-making approach, they may be efficient from an energy-efficiency standpoint, but they may not be contributing to reliability, they may not be traditional investments that a utility would otherwise undertake." Mr. Goulding also questioned the Green Energy Coalition's assertions that all non-capital expenditures would necessarily relate to activities that the utility would be doing anyway and therefore not requiring cost recovery or incentive.

Hydro One is in agreement with Mr. Goulding's stipulation that it is those utility side investments/expenditures which otherwise would not be undertaken that should be eligible for explicit cost recovery and incentives under CDM funding, rather than each and every utility side investment/expenditure that just might happen to provide a CDM effect.

Hydro One believes that initiatives undertaken to minimize / optimize distribution system losses should be eligible for explicit cost recovery and incentives established, as appropriate, under CDM funding. It should be noted that this is required because the current structure does not provide appropriate incentives for distribution utilities to implement initiatives which minimize / optimize distribution losses.

Determination of CDM Funding Levels
Hydro One is in agreement with the approach that Mr. Goulding, Mr. Chernick, Mr. Gibbons and Mr. Heeney all seemed to be supporting, that being one in which distributors develop CDM programs appropriate to their utility and that below a certain level of funding there would be minimal up front review of the level of funding. Beyond that level of funding the Board might wish to have a more in depth up front review of the proposed programs to ensure that the programs are consistent with the CDM guidelines provided by the Board and that the level of planned spending is appropriate. The Board would set and adjust this reference funding level based on CDM experience in Ontario and other jurisdictions, along with input from the Ontario Power Authority, the Independent Electricity System Operator and other stakeholders as to the level of activity required/desired and as to the availability of cost effective CDM initiatives.

Appendix B: Rate Base Accounts

Appendix B Recommendations

Page	Section	Preferred Alternative	Reasoning
157	Definition of Rate Base	Alternative 1	For those utilities filing on an historical year basis, 2004 year-end is the appropriate measurement period. 2006 mid-year is appropriate for those utilities filing on a future year basis.
158	Calculation of Net Fixed Assets, Distribution Assets	Alternative 1	For those utilities filing on an historical year basis, 2004 year-end is the appropriate measurement period. 2006 mid-year is appropriate for those utilities filing on a future year basis.