RP-2004-0188

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

AND IN THE MATTER OF the preparation of a handbook for electricity distribution rate applications.

Submissions by

The Association of Major Power Consumers in Ontario

February 14, 2005

AMPCO SUBMISSIONS ON THE
ONTARIO ENERGY BOARD
2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK
DRAFT 2 - 10 JANUARY 2005

Introduction

On January 10, 2005 the Ontario Energy Board (The Board) issued a draft of the 2006 Electricity Distribution Rate Handbook. The Board in its Procedural Order #5 has requested that intervenors file their submissions by February 14, 2005. As requested in the Procedural Order this submission is structured according to the Chapters and Sections of the January 10th Draft.

Many but not all of the Alternatives included in the draft are addressed. In these cases the Alternatives are identified in this document. If this submission does not address an Alternative, AMPCO is not taking a position on the Alternative at this time. This does not preclude AMPCO taking a position on this issue later in this proceeding or in some other proceeding.

As indicated by Board staff there is no place in the Draft Handbook where Conservation and Demand Management (CDM) issues are discussed. Board staff suggested that parties may want to discuss these issues in a group at the end of their arguments. (Transcript Feb 4, Para 867). Because of the importance of these issues and because the general discussion informs the particular submissions, AMPCO has put its general submissions on CDM before its specific submissions on the Chapters of the Handbook. The subsequent submissions on specific Sections and Chapters refer back to these general submissions as necessary.

General Submission On
Conservation & Demand Management

AMPCO supports Conservation and Demand Management (CDM) programs that are economic and do not impose unnecessary and unpredictable costs on the consumers who will, in the end, foot the bill. However, AMPCO is concerned that the current path of CDM is proceeding in an undisciplined manner with little, or no, assurance that the funds that are approved will be well spent.

On July 16, 2004 the Board issued its Preliminary Guidelines for Electricity Distributor Conservation and Demand Management Activities – A Guide for Conservation and Demand Management Investment. In August AMPCO and a number of other customer groups wrote to the Board expressing concern that the guidelines were not strong enough to ensure that customers would get value for CDM spending as the costs were passed through to them. The customer groups have not had a written reply to that letter.

In late 2004 several utilities sought approval of their CDM programs to spend their final third (3rd Tranche) of Market Based Rate of Return (MBRR). The programs of most utilities that were submitted and approved contained no forecasts of the energy and demand savings of the programs and no tests were performed to ensure that the programs were an economic use of funds. The fears of undisciplined spending were being realized.

On December 1, 2004 Robert Warren wrote to the Board on behalf of the Consumers Council of Canada (The Council) to express several concerns of the Council including the concern that the proposed programs had no forecasts of what would be achieved and had not been subject to any tests to ensure that they were cost effective. Despite these concerns the Council had decided not to intervene because the process being followed would not allow the Council's concerns to be explored. On December 2, 2004 Robert Warren wrote to the Board on behalf of AMPCO supporting the letter from the Council.

AMPCO recognizes that the decisions on the spending of the 3rd Tranche of MBRR funds on CDM cannot be reversed. However, AMPCO submits that they should not be considered indicative of the level of justification required for additional CDM programs. The 2006 Handbook is an opportunity to start the process of establishing the necessary discipline in CDM spending by Distributors. It is vital that this opportunity is not missed so that a culture of unrestrained spending is avoided.

Based on the detailed submissions that follow, AMPCO makes the following general recommendations for CDM in the 2006 Rate Handbook. These recommendations address the five key decision points on CDM which Board counsel invited intervenors to address (Transcript Feb 4, Paras 1034 – 1040):

Recommendations for CDM:

1. **The Board should require new CDM programs beyond those for the 3rd Tranche of MBRR to meet the Total Resource Cost Test as a minimum. A pre-determined target level of CDM spending is not required.**
2. **The Board should work with distributors and the OPA Conservation Bureau to set up a framework that will allow distributors to perform cost-effectiveness tests on proposed CDM programs on a consistent and uniform basis.**

3. **The Board should retain flexibility to accommodate a variety of outcomes with respect to the role of the OPA and others in designing, implementing and evaluating CDM programs for distributors.**
4. **The Board may allow deferral accounts to implement a LRAM mechanism on an after the fact basis. Such claims must be supported by studies showing that the claimed load reductions were a result of the CDM programs of the utility and were not the result of some other factor.**
5. **The distributors should not be allowed to claim changes on the utility side of the meter as CDM programs. However, the utilities should be able to benefit from cost savings due to loss reduction in a similar manner to the benefits to the utilities of reducing other costs of running a distributor.**
6. **The Handbook should not allow a Shared Savings Mechanism for savings as a result of programs that were financed from the 3rd Tranche of MBRR.**
7. **The 2006 Handbook should not provide a SSM mechanism.**
8. **The costs of CDM programs that have an expected life of many years should be capitalized for recovery over the approximate period of benefit to customers.**
9. **The costs of CDM programs should be recorded at a class level for cost allocation so that the costs of CDM programs can be recovered from the appropriate class or classes.**

Implementing CDM programs:

In this proceeding the Board hired Mr. A. J. Goulding of London Economics International to write a report (Exhibit C1) on an Overview of C&DM Practices in North America and Potential Alternatives for Ontario. Mr. Goulding also testified at the oral hearing on February 1st and 2nd.

The design, delivery and regulation of cost-effective CDM programs by Distributors in Ontario represents a significant challenge. Mr. Goulding shows the process of CDM Planning (Exhibit C1, Page 13, Figure 4). In cross-examination of Mr. Goulding, Mr. Warren discussed the several stages of the process for the planning and regulation of C&DM programs and expressly asked Mr. Goulding whether it was reasonable to expect a small utility with perhaps only three employees to undertake such a process. (Transcript Feb 1, Paras 431 – 496). Mr. Warren goes through the process in a series of steps, summarized as follows:

- Prepare a load forecast – not currently being done by distributors
- Identify and evaluate CDM resources – quantitative evaluation against a Total Resource Cost test is not currently being done and even Hydro One, the largest distributor, indicates that "there is currently an inability to apply proposed cost benefit tests that put supply and demand on equal footings" (Transcript Feb 1, Para 349).
- Select the CDM resources within broad parameters set by the Board.
- Stakeholder involvement
- Regulatory review – prior to the implementation of programs Mr. Goulding suggests that this review can be relatively light.

- Additional data and calculations are required before programs are implemented if there are incentive mechanisms. Exhibit C1 Page 14
- After the fact it is necessary to determine whether benefits have actually been achieved and whether or not the money spent actually achieved the benefits. There are problems of attribution when several entities (e.g. Federal Government, gas companies) have programs in the same general areas as the distributors. This process has proved contentious and time consuming in Ontario for Enbridge DSM programs.

Mr. Warren's specific questions addressed the feasibility of this process for 90 distributors. Mr. Goulding did not concede that this was infeasible. With respect to the complex calculations required he said:

> *The fact that they are complex doesn't mean that they're beyond the capabilities of an intelligent manager. And I'm aware that there's several well-managed small utilities in the province. I do believe that these calculations can be structured such that they would be within the capabilities of a small utility. (Transcript Feb 1, Para 479)*

With respect to the after the fact evaluations he said:

> *I have always said that the process is challenging and requires some thought, yes. (Transcript Feb 1, Para 496).*

AMPCO is not as confident as Mr. Goulding in the capabilities of the management of small utilities to perform these calculations and analysis. AMPCO remains concerned that the proposed process of forecasting, screening, evaluating, stakeholdering etc. may be beyond the current capabilities of many small utilities. To adequately perform these tasks these utilities would need consulting help which would likely cost more than the savings expected from the CDM programs. The regulatory oversight required would be unreasonably large and no intervenors would have the resources to participate effectively. AMPCO submits that the Board should form its own opinion based on its knowledge and experience of the capabilities of the various utilities as to the feasibility of this process being carried out by each utility.

One complicating factor in the drafting of the CDM sections of the Handbook is uncertainty about the role of the Ontario Power Authority (OPA). Mr. Goulding addresses this matter in his report:

> *Until the role of the Conservation Bureau is better defined, there is a risk that any electricity distributor C&DM initiative may either be contrary to the government's long term vision for the Bureau, or if successful could make the Bureau irrelevant. Conversely, failure to coordinate C&DM initiatives with Bureau activities could result in suboptimal investment of resources or duplication of efforts. (Exhibit C1, Page 40, Section 7.5).*

Fortunately this can also be seen as an opportunity. The OPA may be able to provide central coordination that replaces or reduces the need for each distributor to design and implement its own CDM programs. At the least, the OPA and the Board in consultation should be able to establish the parameters for performing the TRC Test in a uniform manner across the Province. There is no reason why each distributor should have to do its own estimation of the avoided costs of generation. In fact if each distributor were to use a different value there would be a significant lack of coordination.

Passing the TRC test is the most basic requirement to show that a program is cost effective. The 3rd Tranche spending is, or will shortly be, approved and is outside the scope of the Handbook. Therefore AMPCO recommends:

1. **The Board should require new CDM programs beyond those for the 3rd Tranche of MBRR to meet the Total Resource Cost Test as a minimum. A pre-determined target level of CDM spending is not required.**

This recommendation addresses Board counsel's third key decision point on the level of CDM spending.

The Board has no powers to direct the OPA. Coordination with the OPA must await the formation of the OPA Conservation Bureau and will depend on the policies and direction of the OPA as well as the Board. However, the opportunity for synergies and increased efficiency in designing, evaluating and possibly even implementing programs is large enough that the Board should not, through its Rate Handbook, set up any impediments to OPA involvement.

In addition there were several ideas that emerged in the testimony to deal with the administrative and regulatory complexity associated with 90 utilities each having CDM programs. Mr. Chernick, the witness for the Green Energy Coalition, agreed that the Board could give Type approval of standardized CDM programs that could then be implemented by many distributors (Transcript Feb 3, Paras 662-5). Mr. Chernick also suggested that smaller utilities could form groups to develop CDM programs or simply adopt the approved program of a larger nearby utility (Transcript Feb 3, Paras 516-521).

There will be less than four months from the end of this process to the July 4, 2005 filing date for 2006 rates. Thus, it is unlikely that the role of the OPA bureau and the cooperative mechanisms between the OPA, the Board and distributors will be settled in time for many distributors to file CDM programs by that date with proper cost effectiveness tests and stakeholder consultation. Therefore the rate handbook must retain flexibility to accommodate the outcomes of these processes as they evolve later in 2005 and into 2006.

Therefore AMPCO recommends:

2. **The Board should work with distributors and the OPA Conservation Bureau to set up a framework that will allow distributors to perform cost-effectiveness tests on proposed CDM programs on a consistent and uniform basis.**
3. **The Board should retain flexibility to accommodate a variety of outcomes with respect to the role of the OPA and others in designing, implementing and evaluating CDM programs for electricity customers of distributors.**

Compensating utilities for lost revenue:

The evidence of Mr. Goulding contained two options with respect to compensating distributors for the lost revenue caused by successful CDM programs. One mechanism is prospective and the other retrospective. The retrospective mechanism requires that accounts similar to deferral accounts be established. For the prospective mechanism, there must be a forecast of the load reductions and revenue losses due to the programs. (Exhibit C1). Mr. Goulding expects each distributor to forecast its own load as well as the effects of its CDM programs. (Transcript Feb 1, Paras 429 – 439).

At this time the distributors do not prepare load forecasts. Nor are distributors going to be required to prepare forecasts for 2006 as part of their filing requirements for other aspects of the 2006 rate filing. In addition very few, if any, of the programs for CDM that have been approved for 3rd Tranche spending have estimates of the load reduction or revenue loss as a result of the programs.

Given the current status of the distributors' ability to forecast load, load reductions and revenue loss, it is not reasonable to expect that they will be able to make these forecasts in time for a 2006 rate filing on July 4, 2005. Therefore as a practical matter the only feasible LRAM mechanism is the retrospective mechanism. This is supported by Chernick who indicated that he was not sure that a prospective LRAM made sense (Transcript Feb 3, Para 459).

Therefore AMPCO recommends:

4. **The Board may allow deferral accounts to implement a LRAM mechanism on an after the fact basis. Such claims must be supported by studies showing that the claimed load reductions were a result of the CDM programs of the utility and were not the result of some other factor.**

This recommendation addresses Board counsel's first key decision point on revenue protection.

Incenting Utility Loss Reduction:

AMPCO submits that the primary factor that distinguishes CDM activities from the other business activities of a distributor is that distributors are being asked to influence the use of their product by their customers - in particular to use less of the product and thereby to reduce the distributors' revenues. This is contrary to the normal business model where a business will promote its product to maximize the size of the business and the associated profits. The rules to encourage the distributors to undertake CDM programs related to the customers' use of electricity are designed to compensate for the natural negative business implications of selling less of the product as a result of promoting increased efficiency in use. The special rules to allow the CDM expenses to be recovered, to compensate for lost revenue and to provide incentives to utilities, all relate to creating positive incentives to promote increased efficiency in use by customers.

The distributor itself uses electricity during the course of its distribution business. The largest single use of electricity by the distributor is due to the losses on the distribution system in lines and transformers. Managing these losses should be part of the normal business of running a distribution company. When lines are being built or rebuilt, conductor sizes are chosen taking into account the expected cost of losses over the life of the line. When transformers are being changed, loss considerations may dictate a lower loss transformer with a higher initial cost and a lower cost of losses over the life. In operating distribution systems open points between different feeders may by moved for reasons such as improved reliability. A factor in this decision may include the benefit of balancing loads to reduce losses. It is unlikely that any of these actions is taken for loss reduction alone. For example, it is usually only economic to change a transformer for a low loss transformer when the transformer needs changing for other reasons e.g. it is overloaded.

The view that utility side CDM programs are a normal part of the distribution business was supported by Chernick:

> *Yeah, I guess I'm a little confused as to why a special incentive like -- of the kind that we're talking about with an SSM would be necessary for loss-reducing investments on the utility side of the meter. There aren't any lost revenues. There's no cultural conflict. Installing transformers, capacitors, switching equipment, redesigning the layout of the distribution lines, those are all normal utility activities, and all are the kinds of things that utility -- I mean, the utility managers I've known, have enjoyed doing. Normal cost recovery should be sufficient for those activities. (Transcript Feb 2, Para 923)*

The current regulation for distributors has removed the normal business incentive to make the distributor more cost effective by reducing losses. Losses are a pass-through item. If the distributor reduces losses, the distributor may have increased costs but the benefit is passed immediately to the customers.

AMPCO submits that changes should be made in the loss adjustment mechanisms to restore to the distributor the normal incentive to manage its business in a cost-effective manner. There are proposals at Section 10.5 to allow the distributors to benefit from loss reductions for a period of time. AMPCO supports this proposal. In addition AMPCO does not consider it a productive use of the Board's time to specifically regulate CDM programs on the utility side of the meter. The Board would have to be able to separate the costs of loss reduction programs from the other costs of the utility. Since loss reduction usually occurs at the same time, and as an integral part, of other programs it is not a simple task to separate the costs and benefits.

Therefore AMPCO recommends:

5. **The distributors should not be allowed to claim changes on the utility side of the meter as CDM programs. However, the utilities should be able to benefit from cost savings due to loss reduction in a similar manner to the benefits to the utilities of reducing other costs of running a distributor.**

This recommendation addresses Board Counsel's fifth key decision point regarding the treatment of savings in losses.

Incenting CDM programs:

There is very little evidence to support the need for, or the efficacy of, a Shared Savings Mechanism (SSM) for 2006 rates.

Most of the CDM programs that will be implemented in 2006 will be carried out under the 3rd Tranche funding mechanism. These programs already have a large incentive associated with them. Without these programs the 3rd Tranche of MBRR would not be allowed. No further incentive is required for these programs. In fact adding an additional incentive would be an unnecessary cost which would be imposed on customers.

Most distributors are at present municipally owned. While there may be some divestitures and amalgamations, AMPCO submits that this is likely to still be the case in 2006. Mr. Warren had an extensive discussion with Mr. Goulding on the question of whether incentives were needed to encourage municipally owned utilities to perform CDM programs (Transcript Feb 1, Paras 283- 326). Mr. Goulding had no survey data to support the assertion that incentives were needed. He conceded that some ("a handful") of municipally owned utilities had successful CDM programs without incentives. His assertion that incentives were needed for Ontario municipally owned utilities was based on his non-lawyers interpretation of the fiduciary responsibilities of directors under Ontario law. In short the opinion is based on a series of beliefs with no data or hard evidence to support them.

The Chairman of the panel commented that certainty of cost recovery was far more important to utilities in Ontario than incentives. Even with substantial incentives utilities were not prepared to proceed with CDM programs without certainty of cost recovery.

> *And what we discovered was, regardless of the incentive, these LDCs - the 90 rats, as would you call them - they weren't doing anything unless they were guaranteed there was going to be recovery of those expenses in rates. And this Board issued a Procedural Order and we came up with interim approval, and we thought that would give them some comfort. It didn't give them any comfort at all. And you will recall, if you read the record and you've gone this file, when the big 6 came in, they said, We want a final order and we don't want any conditions on it; and if we don't get it, we're not spending.*
>
> *Now, what that told me is, regardless of what the incentive is, cost recovery is ten times more important. (Transcript Feb 3, Paras 325-6)*

AMPCO submits that there is no evidence that municipally owned utilities in Ontario need a SSM to encourage them to carry out CDM programs.

There is a more general question as to whether even privately owned utilities need a SSM mechanism. Mr. Shepherd, counsel for the School Energy Coalition, had a discussion with Mr. Gibbons, witness for Pollution Probe, regarding the experience of Enbridge before and after the utility was allowed a SSM mechanism. (Transcript Feb 3, Paras 1080 – 1108). Mr. Gibbons agreed that for the period 1995 – 1998 there was no SSM and for some of those years there was no LRAM. Despite the lack of incentives, in each year Enbridge increased its savings although it may not have met the targets set by the Board. AMPCO submits that the evidence is that Enbridge had substantial success without a SSM mechanism.

There is also evidence that SSM mechanisms have requirements for more accurate forecasts and data than just a LRAM. Mr. Goulding's exhibit includes the following:

> *It is important to note that one of the most challenging aspects of establishing well functioning incentive mechanisms is determining "what might have been." In a LRAM, we know what the target level of revenue was, can do simple arithmetic calculations to determine the shortfall relative to the revenue requirement, and can design a mechanism for recovery; we are indifferent to why the volumes dropped, and indeed, had they dropped for a reason other than C&DM we would still likely have had a variance mechanism in place to assure that the utility achieves the required return. By contrast, if we are giving a utility an incentive, we want to be sure that the incentive is being earned; as such, some forms of incentive mechanisms require us to perform forecasts of volumes without C&DM measures, and to show how those volumes would change according to patterns of weather, population growth, and economic growth, again in the absence of C&DM. Simply knowing that consumption dropped does not allow us to say that C&DM measures were a success; likewise, an increase in consumption does not necessarily mean that C&DM programs have failed, if without C&DM volumes would have been higher. The more high-powered the incentive scheme, the more important it is to attempt to measure results; however, the methodology for doing so needs to be clearly established in advance, and the nuances well understood. (Exhibit C1, Page 29)*

AMPCO does not concede that with a LRAM it does not matter whether the load reduction was due to the CDM programs. However, even Mr. Goulding points out a daunting set of increased requirements for the administration of a successful SSM mechanism. AMPCO notes that it is important that the mechanism be established in advance and the nuances be well understood. Given that at this stage the first utility has not yet carried out a TRC test on a single CDM program, it is inconceivable that the level of advanced understanding necessary for SSM incentives will be achieved in time for utilities to prepare submissions for July 4, 2005.

AMPCO submits that a SSM mechanism is not necessary for 2006 rates and that there is no likelihood of meeting the conditions for a SSM to be effective. Therefore AMPCO recommends:

6. **The 2006 Handbook should not provide a SSM mechanism.**

This recommendation addresses Board counsel's second key decision point on shareholder incentives.

Capitalizing CDM programs:

One of the questions being addressed through this process is whether CDM programs should be capitalized and if so over what period should they be depreciated. The discussion of this is clear in Mr. Warren's cross-examination of Mr. Goulding (Transcript Feb 1, Paras 510-514). Mr. Goulding indicates that capitalizing and depreciating over a life that matches the benefits of each program gives the best match between costs and benefits to customers. However, he points out that having different depreciation lives for different programs could be administratively complicated. A possible solution to this is to use one average depreciation life for all capitalized CDM programs. He also says that the policy on capitalization should be established by the Board in advance.

AMPCO agree with these suggestions and recommends:

7. **The costs of CDM programs that have an expected life of many years should be capitalized for recovery over the approximate period of benefit to customers.**

This recommendation addresses Board counsel's fourth key decision point on capitalization of CDM program costs.

Allocating the costs of CDM programs:

It seems likely that most of the CDM programs by distributors will be designed for residential and commercial customers. For these classes programs can be implemented through standardized programs for many similar customers. The efficiency of large industrial users is also important but is not amenable to standardized programs. The main energy uses for a large industrial customer are for the particular process of that industry. The opportunities for improving the energy efficiency are usually process specific. These processes will be completely different between different industries. Even within one industry there can be significant differences in opportunities depending on the age of the facility and the specific equipment in use. AMPCO and its members have been active in a number of projects aimed at improving energy efficiency but that does not imply that there are no further opportunities to improve energy efficiency in industrial plants.

Base on this discussion AMPCO submits that the Large Users that are industrial companies are unlikely to be able to participate in the general CDM programs of the distributors. The Large Users are only likely to be able to participate if the distributors work closely with the Large Users in designing programs that are geared to the class's needs and possibly the needs of individual customers.

Given this discussion, the allocation of CDM program costs is an important issue for AMPCO. The issue of cost allocation was addressed by Mr. Goulding:

The allocation of C&DM costs to customers can be a difficult issue. While C&DM has the potential to lower electricity costs for all customers, there is some concern over non-participant rate impacts. This is particularly true for certain large industrial customers who are relatively sophisticated about energy efficiency and have consequently undergone significant investments in C&DM. Utility C&DM programs have little to offer for these customers. Meanwhile other less efficient customers (who may be competitors to the efficient industrial customers) stand to gain from utility C&DM programs. If the more efficient customers must pay higher rates due to implementation of utility C&DM, then they may perceive themselves to be subsidizing potential competitors and other who are less efficient. (Exhibit C1, Page 10-11)

This is of great importance to AMPCO. Large users of distributors are often in competition with other companies that are either transmission or Low Voltage customers of Hydro One. The former pay no distribution rates and the latter will pay a relatively small charge for the use of the LV system when the LV rates are implemented. Which category a company falls into is largely an accident of history. Under the old Power Corporation Act a municipal utility had a right to supply all the customers in its territory. Some municipalities (e.g. Windsor) exercised this right and even very large industries became customers of the distribution utility. In other cases (e.g. Oshawa) the municipal utility waived its right to serve the large industrial customers and the large industries in its territory were supplied by Ontario Hydro. The result has been that different companies, often in the same industry, have become transmission customers or distribution customers. The addition of CDM program costs for other customer classes to Large Users would be another anti-competitive addition on top of the existing Large User distribution rates.

The letter in August 2004 from AMPCO and other customer groups commenting on the Board's Preliminary Guidelines for Electricity Distributor Conservation and Demand Management Activities supports recording the costs of CDM programs separately by customer class. AMPCO continues to believe that this is the proper policy and recommends that:

8. **The costs of CDM programs should be recorded at a class level for cost allocation so that the costs of CDM programs can be recovered from the appropriate class or classes.**

Impact of AMPCO recommendations:

AMPCO expects that some intervenors will object to AMPCO's recommendations, for example the insistence on cost-effectiveness tests, as being an impediment to the rapid introduction of CDM programs. AMPCO views its recommendations as being supportive of an orderly and cost-effective process for the implementation of CDM programs.

There may be a lull in applications for new CDM programs after the 3rd Tranche applications as Distributors, the Board and the OPA take some time to organize the process for testing CDM programs. However, implementing the approved 3rd Tranche programs may fully occupy the resources that a distributor can devote to implementing

CDM programs. AMPCO notes that most of the 3rd Tranche programs are to be implemented over 3 years including 2006 and into 2007. In addition the level of approved spending is in the range of the CDM spending that has been recommended by some of the witnesses.

AMPCO submits that insisting on a disciplined process will result in little or no CDM opportunities being lost and significantly reduce the possibility of wasteful or ineffective spending.

Chapter 1

Introduction to the 2006 Handbook

Section 1.0 Introduction

The following paragraph should be introduced into this section:

The 2006 Handbook applies only to the preparation of rates for 2006. The Board has committed to significant changes in rate submissions for subsequent years including a commitment that 2007 rate applications will be based on new cost allocation studies and that 2008 rate applications will include rebasing of the distribution revenue requirement. These changes will require substantial modifications to the Handbook for rate submissions for these years.

AMPCO submits that this addition makes it plain that the 2006 Handbook is for 2006 only. Many intervenors have accepted the 2006 Handbook process only on the basis of it being an interim stage before more radical changes that are needed can be made. For example AMPCO has advocated the early implementation of cost allocation studies to correct the large variation in Large User distribution rates between distributors. While this was ruled out of scope for the 2006 Handbook, the Board committed to completing cost allocation studies for implementation in 2007 distribution rates.

Chapter 2

Description of the Application

AMPCO makes no submissions on this chapter.

Chapter 3

Test Year and Adjustments

3.0 Test Year and Adjustments

If an applicant is aware of material events expected to occur in 2006, which are identifiable, quantifiable, and verifiable, it…

Alternative 1: *is obliged to disclose*

Alternative 2: *is not obliged to disclose*

…such events in the description of the application.

AMPCO support Alternative 1 – the obligation to disclose.

AMPCO submits that regulation can only proceed on a satisfactory basis when the regulator is aware of all material circumstances. In addition, it is important that the basis for regulation be available on the public record so that intervenors can contribute to the regulatory process. Therefore AMPCO supports full disclosure as required by Alternative 1.

Tier 1 Adjustments: Distribution Expenses

5.) Low voltage/wheeling adjustments

The applicant should adjust the 2004 base filing for all such costs that are not included in 2004 and are not directed by the Board to be treated as either a flow-through item or placed in a deferral account.

Alternative 1: *The relevant costs would include the following, which should be identified separately:*

1. *LV recovery amounts approved by the Board in the Phase 2 regulatory asset review.*

2. *Proposed LV recovery amounts for the period January 2004 through May 2006.*

3. Proposed Hydro One LV rates post-May 2006

4. Wheeling charges in cases where there are no established rates in place.

As items 1 and 2 are of a transitory nature, they would be recovered through a rate rider. As items 3 and 4 would represent adjustments of a more permanent nature, they would be recovered through base rates, unless the Board deems this to be a transmission service in the future.

Alternative 2: *The relevant costs would include only those for which a Board decision has been made, approving their recovery. The recovery of any LV wheeling charges for which a Board decision has not been made by the application filling date is outside the scope of this proceeding.*

AMPCO supports Alternative 2. There is no basis for setting rates to recover LV charges until the Board makes a decision on the application of current LV charges, the recovery of past LV costs and the period and manner in which the past costs will be recovered. However, AMPCO sees no reason why a Board decision on these matters could not be made in time for Board approved charges to be included in the July 4, 2005 rate applications. All the numerical data is available from Hydro One. All that is required is a regulatory decision to apply the current LV charges and over what time period to recover the past unrecovered LV charges. AMPCO has in the past advocated, and continues to advocate, putting LV charges on a normal pay-as-you-go basis as soon as possible. Delaying the implementation just makes the financial impact on customers worse when the charges are eventually collected.

6.) CDM and Smart Meters

Placeholder in case any adjustments are required.

AMPCO submits that CDM and Smart Meter programs that have been fully funded from 3rd Tranche CDM funds should not be added to Distribution Expenses or Rate Base to adjust the base level of 2006 rates. To do so would be to recover the costs twice.

Additional CDM and Smart Meter costs beyond the 3rd Tranche may be added to Distribution Expenses and/or Rate Base to the extent that the programs are approved at the time of the rate submission. There would be no basis to adjust for programs that had not been approved by the time of the rate submission but programs implemented in 2006 may affect rate applications for subsequent years.

AMPCO is proposing that long-lived CDM programs should be capitalized. Capitalized programs will be reflected in Rate Base rather than Distribution Expenses. This reduces the importance of them being recoverable in rates in the year in which they are implemented.

<u>Tier 1 Adjustments: Rate Base</u>

4.) *<u>CDM and Smart Meters</u>*

Placeholder in case any adjustments are required.

See the previous discussion under item 6.) of Tier 1 Adjustments: Distribution Expenses.

Adjustment for New Transformer Stations

Alternative 1: *6.) New transformer stations and directly-associated (e.g. feeders) with an in-service date of 2006 (half-rule). See above for an explanation of the half-rule.*

Alternative 2: *exclude*

AMPCO supports Alternative 2 – not to include new transformer stations. The addition of a new transformer station is no different to other capital expenditures to accommodate load growth. Load growth generates extra revenue without higher rates. It is only by doing a forward test year application that a distributor could give the regulator the information to know whether, on balance, rates should be raised because of the increase in rate base or should be lowered because of the increase in load.

Implementing Alternative 2 requires the corresponding changes to the Table of Tier 1 Adjustments on Page 18 and to Schedule 3-1 Tier 1 Adjustments.

Option 2: <u>Tier 2 Adjustments</u>

Tier 2 adjustments will have two components: adjustments to distribution expenses, and adjustments to the rate base in order to achieve sustainable levels of expenses and capital on a going-forward basis.

Alternative 1: *Tier 2 adjustments must not include any additional requests for hardship funding to address material degradation of the distribution system which may have occurred in prior periods, due to reduced revenue arising from the existence of the eligibility circumstances for the Tier 2 adjustments.*

Alternative 2: *Tier 2 adjustments may also include additional requests for hardship funding, which would be intended to address an identified material degradation of the distribution system resulting from the existence of one or both of the Tier 2 qualifying circumstances, as opposed to a normal **on-going***

> *level of expense and investment. This is additional distribution expenses and capital expenditures related to prior years which the applicant believes is necessary to take corrective action for monies not spent in such prior years due to inadequate revenue as a result of the two circumstances outlined above. Any such amounts approved by the Board will be recovered with a rate rider to be in place for the period over which the corrective investments are to be undertaken.*

Illustrative Example of the Differences Between Alternatives 1 and 2

Assume a distributor did not receive the second third of the market adjusted revenue requirement increment and that this amount was $50,000.

Under Alternative 1, the distributor would be able to apply for a 2004 adjustment to either capital, expenses, or both, of not more than $50,000. The applicant would have to justify the proposed breakdown of the claimed recovery amounts between expense and capital.

Under Alternative 2, the distributor would be able to apply for an additional adjustment. If it is assumed that the applicant had not received $50,000 for three years related to the second third of the market-adjusted revenue requirement increment, the distributor could apply for a maximum $150,000 in additional adjustments to recover this prior years' shortfall. As is the case with Alternative 1, the applicant would have to justify the proposed breakdown of the claimed recovery amounts between expense and capital.

AMPCO supports Alternative 1 with no retroactive hardship funding. There is no end to the retroactive requests that can be made if attempts are made to correct for past inequities. For example, if the cost allocation studies for 2007 rates show that a utility's Large User rates are too high, AMPCO doubts that many utilities will support a retroactive refund of the past overpayment.

Implementing Alternative 1 requires the corresponding changes to Schedule 3-3; Tier 2 Adjustments.

Chapter 4

Rate Base

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

The interest rate to be used for deferral accounts is…

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

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

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

The interest rate to be used for construction work in progress (CWIP) is…

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

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

AMPCO recommends that in both cases the interest rate allowed should be Alternative 2: some form of short term debt rate. The debt that a distributor takes on for these short term requirements should match the term of the circumstance creating the need for the debt.

Construction Work In Progress (CWIP) generates a need for funds at maximum for the construction period. Few distribution company projects will have construction periods longer than a year.

Most deferral accounts for routine variances (e.g. variances due to the mismatch between wholesale transmission costs and retail transmission revenues) should be cleared as part of the rate setting process for the following rate period. The maximum time that requires financing should be two years. A variance that occurs early in one rate year should be cleared by the end of the next rate year.

There are some larger deferral accounts that are being recovered over multiple years, for example the recovery of Market Ready costs. The regulation by the Board of these variance accounts aims to recover them over four rate years, 2004, 2005, 2006 and 2007. Therefore even for 2006, the recovery should be complete in a two year period from the start of the 2006 rates.

Chapter 5

Cost of Capital

5.1 Maximum Return on Equity

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.

AMPCO supports Alternative 1. In this case the return on capital is determined before the rate submission and there is no need for the administrative complexity of yet another variance account. The return on equity is to represent the return on long term investments – the methodology is based on 10-year and 30-year bond rates. There is no reason to believe that these will vary so much over a period of a few months that updating is required. AMPCO notes that the last time the ROE calculation was updated was in Dr. Cannon's paper dated December 1998. It appears to have been reasonably satisfactory for more than 6 years with no update. There is no reason to believe that an update from March 2006 to December 2006 is necessary.

5.4 Working Capital Allowance

5.4.1 Introduction

Alternative 1: *For 2006 rates, the allowance is calculated at 15% of the distribution cost of power, and other power supply expenses and controllable expenses. The general ledger accounts to be included in the working capital allowance are set out in Appendix B, Table B.2.*

Alternative 2: *The historical cost of power should be adjusted to better reflect the actual costs expected to be incurred. An* *adjustment is required to reflect upward pressure on electricity prices due to legislative initiatives that cause changes in electricity generation supply mix and supply availability.*

In calculating the WCA, an adjustment to the cost of power and other power supply expenses is made, based upon a forecast of rates covering the rate period, prepared by the IMO, or other approved authority. This adjusted figure is used as the cost of power and other power supply component in the calculation.

Alternative 3: *If the forecast cost of power is not available under Alternative 2, distributors will be permitted to track the difference between the estimated and the actual cost of power in a variance account. The variance will be used to calculate the dollar value of the return due to/from the distributor's customers.*

Alternative 4: *For 2006 rates, the working capital allowance is calculated as follows:*

*[COP + 2004 Distribution Expenses with Adjustments (excluding depreciation)] * 15%*

Cost of power (COP) will be calculated in the model under COP and Contr. Expenses. COP is a function of wholesale kWh and kW volumes per customer class, multiplied by the class-specific rates for each component of the cost of power. The test year averages of kWh and kW per customer class are calculated on the Customer Demand Data page in the 2006 EDR Model, and are then adjusted for losses, where applicable, and linked to COP and Contr. Expenses.

2004 Distribution Expenses with Adjustments (excluding depreciation) will be derived from the Tab: Distribution Expenses with Adjustments, and linked to COP and Contr. Expenses.

AMPCO submits that working capital allowance is an approximate amount where requirements could differ for different utilities, for example due to different billing cycles. Undue precision is not required at the expense of administrative and regulatory complexity. In setting rates for Standard Service Supply or Designated Customers the Board may use a forecast of the cost of power. AMPCO has no objection to using this forecast, if readily available, to adjust for the expected future level of the cost of power as proposed in Alternative 2. However, if this forecast is not available in time, AMPCO would recommend the administrative simplicity of Alternative 1.

Whichever of the four alternatives above is selected by Board, an additional adjustment could be made:

Additional Adjustment Alternative 1:

The sum of the working capital accounts is to be reduced by the dollar value of customer security deposits. The result will be multiplied by the 15% allowance.

Additional Adjustment Alternative 2:

No adjustment for customer security deposits is made in the calculation of WCA.

AMPCO supports Additional Adjustment Alternative 1: the adjustment of the working capital to take into account customer security deposits. The working capital is largely to finance power bills from the time the IESO bills must be paid until power bills are paid by customers. Customer deposits substantially reduce the financial risk to utilities for financing power purchases and an adjustment in working capital allowance is appropriate.

6.2.4 Advertising, Political Contributions, Employee Dues, Charitable Donations, Meals/Travel and Business Entertainment, Research and Development

Charitable contributions

Minimum Filing Requirements

All applicants are to file the amounts paid in charitable donations for the years 2002, 2003, and 2004.

Alternative 1*: *Partial Recovery

50% of charitable contribution expenses will be included in the determination of the applicant's 2006 revenue requirement, with the following exception:

100% of charitable contribution expenses made to programmes that provide assistance to the distributor's customers in paying their electricity consumption bills, will be included in the determination of the applicant's 2006 revenue requirement.

Additional Minimum Filing Requirements:

Applicants must review their 2004 expense data to segregate charitable contributions into those that are 50% recoverable (Type A), and those that are 100% recoverable (Type B). Applicants must record 50% of Type A contributions as being non-recoverable, and remove this amount.

Alternative 2*: *No Recovery

No charitable contribution expenses will be included in the determination of the applicant's 2006 revenue requirement.

Additional Minimum Filing Requirements

Applicants must review their 2004 expense data to identify, disclose, and remove such amounts as non-recoverable.

Alternative 3*: *Full Recovery

100% of charitable contribution expenses will be included in the determination of the applicant's 2006 revenue requirement.

No amounts are to be either identified or removed as being non-recoverable.

AMPCO supports Alternative 2: No Recovery. It is not that AMPCO members are against charitable contributions. Many AMPCO members contribute to local and wider charitable organizations. They do so with the companies own money and cannot recover the costs as additional charges to their customers. Distribution companies should be in the same position. They can choose to make charitable contributions with their shareholders funds but should not be able to pass that along to customers as an additional cost.

Alternative 1 has the additional disadvantage of administrative complexity in separating charitable contributions into two categories and the regulatory oversight necessary to ensure that this is done correctly.

6.2.5 Employee Total Compensation

2. Minimum Filing Requirements

Guidelines for applicants with fewer than three employees

***Alternative 1*:** *Where the total number of employees for a given applicant are two, or fewer, and the average total compensation per employee is less than $100,000, no employee compensation reporting shall be required under this section.*

***Alternative 2*:** *No specific filing guidelines for applicants having two, or fewer, employees. Minimum filing requirements outlined above to be applied to all applicants.*

AMPCO supports Alternative 2; full disclosure of total compensation cost to the extent allowed by protection of privacy laws. Distributors are companies that are regulated in the public interest by the Board. It is unacceptable if a significant part of the distributor's costs are not open for review by the regulator and other interested parties because, due to the small size, it may be possible to infer the approximate compensation level of one or more of the employees.

3. Incentive plans

Distributor incentive compensation plans reward employees for meeting specific performance targets. The targets can include performance which benefits ratepayers (e.g. targeted reduction in departmental OM & A expense per employee), or which benefits primarily the shareholder (e.g. percentage increase in share value).

Alternative 1: *The criteria used in any performance incentive plans must be of substantial benefit to the ratepayers in order that the amount can be included in determining 2006 revenue requirement.*

Alternative 2: *Payments for that portion of incentives that provide immediate benefits primarily to the shareholder are not eligible as a distribution expense in the approved 2006 revenue requirements, and must be considered non-recoverable.*

AMPCO supports Alternative 2. The customers should not be required to pay for an incentive plan that is geared to benefiting the shareholder.

6.2.7 Distribution Expenses Paid to Affiliates

Affiliate transactions

At the time of writing, the Board has recently released its amendments to the Affiliate Relationships Code for Gas Utilities and Interpretive Guidance to the Code. Participants may wish to review these documents in making their arguments on this section of the 2006 Handbook.

Distribution expenses incurred through the purchase of services or products from affiliate companies ("affiliate transactions") must be documented and justified as part of the 2006 revenue requirement.

Minimum Filing Requirements

Distributors must file the following information for the years 2002, 2003, and 2004.

Where reported distribution expenses are incurred through affiliate transactions, the following information is to be included in Schedule 6-3 (a) ***(to be written)****:*

- *identity of each affiliate transacting with the applicant*

- *summary of the nature of the activity transacted with each affiliate*

- *annual dollar value, in aggregate, of transactions with each affiliate*

- *identify whether a market-based pricing or a cost-based pricing was used for each transaction*

- *description of general methodology used in determining prices*
  - *e.g. summary of the tendering process, where market-based pricing was used*

  - *e.g. summary of the approach, where cost-based pricing was used*

Proposed Additional Filing Guidelines

***Alternative 1*:**

- *actual costs of the affiliate, where cost-based pricing was used for services or goods provided by the affiliate to the applicant*

- *description of if and how the absence of a market was established before using cost-based pricing*

***Alternative 2*:** *No additional filing requirements are necessary.*

Additional Wording

Alternative 1: *To help justify the reasonableness of amounts paid to affiliates for purposes of 2006 distribution rates, an applicant must provide a general explanation in Schedule 6-3 on how it followed the transfer pricing and shared service rules in the Affiliate Relationships Code.*

Where an applicant failed to follow a material requirement in the Affiliate Relationships Code transfer pricing and shared services rules, it will face additional scrutiny of these expenses in its 2006 distribution rate application. In such cases, the Board will specifically review the reasonableness of allowing full recovery of the amounts paid in the given circumstances.

Alternative 2: *Omit the above statements.*

The purpose of contracting out is to get competitively priced services. AMPCO is concerned that utilities that contract out significant parts of their operations to affiliated companies may have opportunities to avoid regulatory scrutiny of the costs of the affiliate or to shift profits to the affiliate at the expense of the customers of the regulated utility. These actions are not supportive of lowering costs through the use of competitively priced services. AMPCO supports the Proposed Additional Filing Guidelines Alternative 1 and the Additional Wording Alternative 1. This may impose additional administrative overhead on the companies with significant contracting to affiliate companies but will also act as an encouragement to use contracting out for its intended purpose.

Chapter 7

Taxes / PILs

AMPCO has not hired a tax expert to review this chapter and makes no submissions at this time.

Chapter 8

Revenue Requirement

There are no Alternatives in this chapter on which the Board is inviting submissions. However AMPCO notes that its recommendations on CDM as it affects both distribution expense and rate base, and its recommendations on capitalization and cost allocation have implications that affect the calculations described in this chapter.

Chapter 9

Cost Allocation

9.2 Determination of the Appropriate Share of the 2006 Revenue Requirement for Each Class, Sub-Class, or Group

2. CDM programme impacts

If the applicant has CDM programmes that are expected to decrease load by a material amount, the load impact on each applicable rate class, sub-class, or group, must be taken into account when completing Schedule 9-3.

This is not an area where there is an identified Alternative. However, given the state of development of CDM programs AMPCO submits that this paragraph should be deleted for the 2006 Rate Handbook.

AMPCO understands that the purpose of the proposed forecast of decreased load is to shift the proportions of distribution expenses allocated to customer groups rather than being a LRAM mechanism. However, as discussed in the general submissions on CDM, forecasts of program impact are unlikely to be available by July 4, 2005 for a prospective LRAM mechanism. The forecasts contemplated by this paragraph are more detailed than required for a prospective LRAM because they need to be by "applicable rate class, sub-class or group." There is no reasonable expectation that these forecasts will be available therefore the paragraph is unnecessary.

3. Smart Meter programme impacts

If the applicant expects any material decrease in billing quantities as a result of its Smart Meter programme, the load impact on the applicable class(es), sub-class(es), or group(s) must be taken into account when completing Schedule 9-3.

AMPCO also submits that the distributors are in no position to forecast the impacts of Smart Meters for a July 4, 2005 submission and that this paragraph is unnecessary for the 2006 Rate Handbook.

9.3 Determination of the Appropriate Share of the 2006 CDM, Smart Meter, and Regulatory Asset Revenue Requirements

The 2006 EDR Model requires allocation factors for each of the revenue requirements as input.

The CDM component of revenue requirement will be allocated in the following manner: ***to be determined***

The Smart Meter component of revenue requirement will be allocated in the following manner: ***to be determined***

AMPCO's position on these matters has been discussed previously. The costs of CDM and Smart Meters should be recorded on a class-specific basis which provides the data to allocate these costs to the classes where the money was spent.

Chapter 10

Rates and Charges

10.5 Update of Loss Adjustment Factor Reflecting System Losses Including Unaccounted-for Energy

A distributor's adjustment factor to reflect system losses, including unaccounted-for energy, should reflect the current situation, to the extent practical.

The applicant must file Schedule 10-5 to update its current loss adjustment factors, including class-specific factors, that were established as part of its original rate unbundling process. The 2006 loss factor adjustments shall be based on a three-year average (2002, 2003, and 2004).

If the applicant determines that specific information warrants a departure from that average (e.g. gain or loss of large customers), it must include in Schedule 10-5 a description of the change from the proposed methodology, with a detailed explanation and justification for the variance.

Alternative 1: *Variances in distribution system losses costs, including both variances in loss volumes (kWh) and variances in the electricity commodity cost per kWh will be either credited or debited to the **XXX** Variance Account in accordance with the current practice. All distribution system losses cost variances, therefore, will be pass-through items.*

Alternative 2: *An amount, equal to the distributor's actual 2006 average annual electricity commodity cost per kWh times the loss volumes (kWh) originally projected and included in rates, will be calculated after the end of 2006. To the extent that this amount is greater or less than the dollar amount of distribution system losses costs used for 2006 rates, the difference will be either credited or debited to the **XXX** Variance Account. Only distribution system losses cost variances caused by electricity commodity cost variances, therefore, will be a pass-through item.*

AMPCO supports Alternative 2 because it helps to restore the incentive for a utility to control losses.

With Alternative 1, which is the status quo, all variances in losses are passed through to customers. This includes variances in the quantity of losses and variances in the prices charged for losses from the wholesale energy market. As discussed in the general submissions on CDM, this removes the incentive for the distributor to control the loss costs. Loss costs are part of the normal costs of running a distribution business. The distributor should have the same incentives to control these costs as other costs.

Alternative 2 restores a large measure of the cost responsibility to the distributor. With this alternative the distributor benefits from any reduction in the volume of losses from the average for 2002, 2003 and 2004. The variance account continues to protect the distributor from deviations due to changes in the wholesale cost of energy.

AMPCO submits that the benefit to the distributor from reduced distribution losses should not persist indefinitely. Most loss reduction activities such as buying low loss transformers require increased capital spending. This additional capital will be included in rate base when the rate base is re-evaluated. At that time customers will pay for the cost of the loss reduction and should benefit from it.

Since the rate base for 2006 rates is based on the 2004 rate base with adjustments, it is possible that some capital spending in 2002 and 2003 that reduces losses relative to the 2002 year is already included in rate base. Therefore Alternative 2 may allow the distributor double recovery of some component of loss reduction costs. However, this amount is likely to be small and, on balance, Alternative 2 is the better of the two alternatives presented.

10.7 <u>Standby Charges</u>

Ongoing distribution costs from a customer with load displacement generation facilities behind the meter must be recovered, in order to reflect the need for distribution system facilities as a backup, or in reserve, when the load displacement facilities are not operating.

All applicants will use the following methodology. Each distributor must file Schedule 10-7 to identify its acceptance of the proposed methodology.

Subject to arrangements made between the customer and a distributor with respect to planned outages for maintenance, etc., for every month when the customer does not require the distributor to provide emergency supply (i.e. the load displacement facility has operated), the distributor would apply the regular distribution volumetric rate to an agreed-upon "contracted standby demand" (typically, the name-plate rating of the load displacement facility) in addition to the customer's regular billing demand.

To lessen the possibility of double recovery of distribution costs, when the distributor supplies electricity normally supplied by the load displacement facility, the standby charge would be dropped and the customer would be billed on the metered demand.

The distributor may apply for a monthly administration charge to cover the incremental cost of monitoring, billing, and administration related to providing this service. Such a charge will require a separate cost-justified submission as part of the distributor's Specific Service Charges.

A distributor may wish to propose an alternative to the preceding methodology. For example, after consultation with its customer, it may consider a more detailed direct assignment of costs would be appropriate. If so, the applicant must complete and file the last part of Schedule 10-7 outlining the methodology it proposes, with a detailed explanation and justification for the variance from the proposed methodology. A sample framework is provided in Schedule 10-7.

AMPCO submits that the last paragraph needs to give more weight to the customer's wishes. Direct assignment of costs is often possible for large industrial customers who are usually supplied through specific identifiable lines and transformers. Direct assignment of costs is more accurate than indirect methods allocating the total costs of the utility according to the proportions of load. Direct assignment, by its nature, will not lead to inappropriate transfer of costs to other customer classes.

The suggested rewording of this paragraph is:

A distributor, or a customer with embedded generation, may propose an alternative to the preceding methodology. For example, after consultation with its customer, the utility or the customer may consider a more detailed direct assignment of costs would be appropriate. If the distributor and the customer agree, the applicant must complete and file the last part of Schedule 10-7 outlining the methodology it proposes, with a detailed explanation and justification for the variance from the preceding methodology. A sample framework is provided in Schedule 10-7. If the distributor and customer do not agree on a change from the preceding methodology, the applicant must include a statement to that effect and invite the customer to add comments for the consideration of the Board.

Chapter 11

Specific Service Charges

AMPCO makes no specific submissions on this chapter.

Chapter 12

Other Regulated Charges

AMPCO makes no specific submissions on this chapter.

Chapter 13

Mitigation

13.1 Impact Analyses

The establishment of electricity distribution rates based upon an updated revenue requirement (as a result of revisions to rate base and return criteria), together with modifications to cost allocations and other rate design issues, will result in bill impacts to customers within a class, sub-class, or group.

Impact analyses must be competed by the distributor and filed as part of its application.

Calculation of these bill impacts will be an integral component of the 2006 EDR Model. An applicant must enter its 2005 rates into the 2006 EDR Model.

In conducting an impact analysis for each class, sub-class, or group of customers, both of the following comparisons will be provided by the 2006 EDR Model.:.

- *The comparison between bills based on the proposed and the existing rates (including Board-approved rate riders or adders), based upon a customer's "total" bill (including a commodity component and other rates), in order to get an order of magnitude.*

  It is understood that the commodity price and other rates are not known at this time. The bill comparison, therefore, should assume a constant commodity price and other rates, despite potential changes as a result of the Regulated Price Plan, other rate changes, and Smart Meter fees, as applicable.

- *The comparison between bills based upon the proposed and the existing rates (including Board-approved rate riders or adders), based upon the "distribution" component of a customer's bill (i.e. excluding the commodity component and other rates).*

  This comparison removes any uncertainty about the levels of the "non-distribution" rates, and only focuses on those aspects of a customer's bill that are directly approved by the Board.

AMPCO is pleased to see the comparison based on the distribution rate only being included. Previous impact calculations have allowed the large increases in the costs for distributors to be diluted by calculating the impact on the total bill. The distributor is responsible for controlling distribution rates. If distribution costs are 25% of the delivered cost of power and distribution rates rise 20% because distribution costs are out of control, it does not make the increase more acceptable to express it as a 5% increase in the total delivered cost.

13.2 Mitigation Methodologies

If an applicant undertakes any mitigation measures that are to be included in its 2006 rates (e.g., changes to the fixed/variable split), it must provide a detailed description and justification of the measures taken.

*An applicant must file the following information if its rates/rates for certain classes exceed **X%** **(contested)**.*

AMPCO submits that mitigation measures should be contained within customer classes.

In addition AMPCO submits that the percentage that triggers the increased filing requirement should be based on a percentage of the distribution rate rather than a percentage of the delivered cost. This is important to Large Users because of the relative size of the distribution and total delivered costs. The distribution rates to Large Users should be of the order of 5% or less of the total delivered cost (under Ontario Hydro regulation of municipal utilities this figure was set at 3%). Consequently a 20% increase in distribution rates if expressed as a percentage of the delivered cost would be reported as 1%. However, a 20% increase in distribution costs would be a significant amount of money. Some larger companies pay of the order of $1 million per year in distribution costs alone. A 20% increase in distribution costs would be a substantial extra cost.

AMPCO submits that the percentage triggering the need for additional filing should be 10% of the distribution rate.

Chapter 14

Comparators and Cohorts

AMPCO believes that a benchmarking process is the only means of effectively regulating 90 distributors without excessive regulatory costs. The Comparators and Cohorts process proposed by the Board's expert Robert Camfield is a good first step towards effective benchmarking even though for 2006 it will only be used as a screening mechanism.

It is only by using a method such as this as a screening tool that the experience will be gained that will eventually allow this method, or some other similar method, to be used for benchmark regulation.

For the 2006 Rate Handbook and setting 2006 distribution rates AMPCO supports the method described in by Mr. Camfield in Exhibit B-4 and the additional text proposed by him in Undertaking E.6.3:

> *The Comparators and Cohorts Mechanism will be used to assist Board Staff to screen and review EDR rate filings by the Local Distribution Companies (LDCs) within the Ontario Energy Board's 2006 EDR proceeding. The mechanism provides an objective basis to determine comparable peer groups (Cohorts) and to compare the costs (Comparators) of the LDCs of the Province of Ontario.*
>
> *The Comparators and Cohorts Mechanism is defined as a four-step analytical procedure, as follows:*
>
> 1. *<u>Screen and Organize LDC Data:</u> LDC data and information regarding costs, resource inputs, output quantities, and technology and business descriptors will be analyzed with modern statistical tools. Statistical tools and methods will be utilized to assess data quality (reliability, accuracy, and consistency), and to help understand relationships among data. For each of the unbundled services, the data will be organized according to defined cost categories.*
> 2. *<u>Determine Cost Drivers with Econometric Methods</u>: Econometric methods will be utilized to determine the statistical relationships between cost categories and resource inputs, and cost drivers. Cost drivers include output quantities and unit-of-output quantities; and market context and technology descriptors (together referred to as business context).*
> 3. *<u>Determine Cohorts with Clustering Methods</u>: LDCs will be assigned to Cohorts with cluster analysis. Cluster analysis will group LDCs according to similarity of cost drivers including output quantities and business context.*
> 4. *<u>Determine and Report Cost Comparators</u>: For pre-defined comparators (heretofore referred to as comparative diagnostics), each LDC will be*

gauged according to its relative position within the statistical distribution of costs of the LDCs within its Cohort (peer group) and as a whole.

Comparators (Step 4 of the C&C Mechanism) refers to unit-of-output and other comparative cost metrics. Comparators will be used to gauge the relative cost performance of the LDCs, and will be determined for the cost categories of each of the unbundled services. For each of the unbundled services and administration, two cost categories will be defined:

- *durable resource inputs (capital) recorded as assets but measured as net capital stock;*
- *non-durable resource inputs including labor and non-labor costs recorded as operating expenses.*

Cohorts (Step 3 of the C&C Mechanism) refers to peer groups of LDCs. Cohorts will be determined for each of the two cost categories of unbundled services and for administration, according to similarity of cost drivers. Cohorts will be obtained by applying cluster analysis methods to weighted or unweighted cost drivers, as determined in Step 2 of the C&C Mechanism. A cost driver's weight will be based upon the absolute value of the elasticity of cost with respect to the cost driver.

In addition Mr, Camfield specified in Exhibit 6-3 the C&C Utility Filing Information that must be provided. AMPCO supports the filing of this information.

One of the more difficult aspects of the benchmarking process is finding an appropriate measure of the capital in use given that the capital is recorded at historic cost less accumulated depreciation and different utilities have different age profiles of capital in use. AMPCO supports Mr. Camfield's needs for historic data and for accurate filing of current data. Accumulation of accurate data over many years will allow improved benchmarking in the future.

The proposed C&C process is a good start but it will need enhancement in the future. The process currently proposed only compares among Ontario distribution utilities. It gives no information on how Ontario distribution utilities compare to distribution utilities in other jurisdictions. In the future it will be highly desirable to develop benchmarks for comparing to utilities in other jurisdictions.

Chapter 15

Service Quality Regulation

This chapter is largely a repeat of the chapter in the previous rate handbook. AMPCO makes no specific submissions on this chapter.