Canadian Manufacturers & Exporters

Ontario Division

RP-2004-0188

ONTARIO ENERGY BOARD

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

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

Final Argument in Chief

On Behalf of

CANADIAN MANUFACTURERS & EXPORTERS

February 14, 2005

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CANADIAN MANUFACTURERS & EXPORTERS (CME)

Final Argument in Chief

1.0 Introduction

1.1 Canadian Manufacturers & Exporters (CME) is a not for profit organization funded by membership fees. CME members represent 75 percent of all manufactured output in Canada (and Ontario) and 90 percent of exports. Although CME represents a number of large corporations, nearly 80 percent of its members are small and medium sized companies. No other stakeholder at the 2006 EDR represented the interests of SMEs.

1.2 CME's vision is to improve the competitiveness of Canadian industry and to expand export business. As such it is keenly interested in ensuring the secure supply of electricity, in the volatility of electricity prices and in ensuring that delivery rates are just and reasonable,

1.3 CME participated in the 2006 EDR C&DM, Taxes/PILs Working Groups and the Rate Base & Revenue Requirement Executive Committee to represent the interests of all manufacturers, from small and medium enterprises (SMEs) to large firms.

1.4 Since intervenors may argue any aspect of the 2006 Draft Rate Handbook, CME has chosen to take a comprehensive approach in its comments. That is it has chosen to comment on each Chapter of the Handbook, rather than just those areas where it disagrees with the draft as written.

1.5 Conservation and Demand Management (C&DM) was not included in the Draft Handbook, but at the hearing parties were invited to discuss six issues. (Transcript February 4, Paragraphs 855, 867, 1034 through 1040) CME's C&DM comments are set out in Section 23.

2.0 Chapter 1 – Introduction to the Handbook

CME's Position

2.1 CME supports content of this chapter as written.

3.0 Chapter 2 – Description of the Application

CME's Position

3.1 CME supports content of this chapter as written, with one change, namely that title of section 2.1.3 be changed to read "Special Licence Conditions or Exemptions," and the text in that section to read:

> "The description of the application should include a statement of whether the distributor has any special conditions in its licence, or if it is exempted from any specific conditions of its licence, that will affect the review of this application."

4.0 Chapter 3 - Test Year and Adjustments

CME's Position

4.1 CME supports the proposal that:

4.1.1 The methodology of the 2006 Handbook should be based upon the principle of building rates from costs, using a test year derived from the applicant's 2004 (historical) audited financial statements, subject to adjustments.

4.1.2 Where any restatements and / or changes in accounting policy have occurred which affect opening 2004 balances, the data filed in the application should be based upon the audited financial statements, incorporating only those changes that the applicant's auditor has accepted.

4.1.3 If an applicant is aware of material events expected to occur in 2006, which are identifiable, quantifiable, and verifiable, it must disclose such events in the description of the application.

4.1.4 Applicants have three filing options:

4.1.4.1 **Option 1**:2004 (historical) audited financial statements with **mandatory** adjustments, defined as Tier 1 adjustments.

4.1.4.2 **Option 2:**In addition to the **mandatory** Option 1 adjustments, further **optional** adjustments, defined as Tier 2 adjustments, may be considered for applicants who meet the criteria specified for hardship.

4.1.4.3 **Option 3**:Forward test year with full supporting documentation commensurate with the nature of the application.

4.1.5 Applicants must file on the basis of a forward test year if it wishes to make any adjustments to its application beyond those outlined in the Tier 1 and Tier 2 categories.

4.2 CME also supports the proposal that:

4.2.1 The Test Year and Adjustments guidelines should **only** relate to Options 1 and 2, outlined in paragraphs 4.1.3.1 and 4.1.3.2.

4.2.2 Applicants filing under Option 3, the forward test year, should also be expected to provide all information that is required for Appendix D, the 2006 EDR Model.

4.2.3 Whichever option an applicant chooses, three years of historical supporting data - 2002, 2003, 2004 - must be included with the application, as set out in the 2006 EDR Model.

CME's Position - Option 1: Tier 1 Adjustments

4.3 CME supports the proposal that:

4.3.1 Tier 1 adjustments should be **mandatory** and serve two purposes:

4.3.1.1 To move the 2004 year-end closer to a "typical" year of capital investment, operations, and revenues through the use of non-routine adjustments, applying to 2004 only.

4.3.1.2 To allow for subsequent year adjustments as specified. Applicants wishing to make any other post-2004 adjustment must file on a forward test year basis.

4.3.2 Tier 1 adjustments should be made in the form of debits and credits to the relevant 2004 year-end balance (i.e., distribution expense, rate base, or revenue) and involve:

4.3.2.1 **Distribution expenses adjustments** – OEB annual dues, pensions, insurance, non-routine/unusual adjustments (exceeding a materiality threshold of 0.2% of total distribution expenses before PILs and adjustments), low voltage/wheeling adjustments and C&DM and Smart Meters (if required).

4.3.2.2 The relevant distribution costs would include only those for which a Board decision has been made, approving their recovery. The recovery of an LV wheeling charges for which a Board decision has not been made by the application filing date is outside the scope of this proceeding.

4.3.2.3 **Rate Base adjustments** – New transformer stations, retirements without replacement, wholesale meters and C&DM Smart Meters (if required) and non-routine/unusual adjustments that are applicable to 2004 only and exceeding a materiality threshold of 0.2% of net fixed assets before adjustments.

4.3.2.4 For new transformer stations and directly-associated assets with an ins-service date of 2006, the half-rule states that only half of the rate base impact should be included in the adjustment, on the basis that 2006 is the forward-looking, rate-setting year, and such adjustments would be assumed to occur on average in mid-year, if a forward test year had been used.

4.3.3 Mergers and acquisitions taking place after 2004 should be dealt without outside of the 2006 rate-setting process.

4.3.4 If an applicant determines that an event which may appear to be non-routine or unusual should not be the subject of such an adjustment, the applicant should provide a full explanation why this is the case. For example, a significant increase in an expense item in 2004, which is expected to be sustained in subsequent years, might not require an adjustment.

CME's Position - Option 2: Tier 2 Adjustments

4.4 CME supports the proposal that:

4.4.1 Applicants, in addition to the **mandatory** Tier 1 adjustments, may also choose to apply for Tier 2 adjustments, which are **optional**. Such Tier 2 adjustments would restore both capital investments, not made and distribution expenses not incurred due to one or both of:

- The applicant began the 1999 Rate Design and Unbundling Model (RUD) process with negative returns.

- The applicant did not receive the second third of the market-adjusted revenue requirement (MBRR) increment.

4.4.2 Unless the applicant meets one or both of the above criteria, the applicant is **not** eligible for Tier 2 adjustments.

4.4.3 Even if the applicant is eligible for Tier 2 adjustments, however, it is the applicant's option as to whether or not it chooses to apply for them.

4.4.4 Tier 2 adjustments are not an entitlement. They represent the amount of distribution expenses and capital expenditures that the applicant believes it was not able to spend (as outlined in 3.6.1), but now wishes to spend.

4.4.5 In order for the Board to approve proposed Tier 2 adjustments, the applicant must:

- Demonstrate that it has suffered hardship as a result of one or both of the circumstances as outlined in 3.6.1.

- Demonstrate that the proposed incremental distribution expenses and capital spending levels are justified by the hardship it has experienced, including how the applicant determined that these amounts are attributable to the two circumstances as outlined in 3.6.1.

- Provide details on the activities that will be undertaken if the proposed incremental spending is approved, including specific details as to the nature of the envisaged activities and their timing on a monthly basis

4.4.6 Tier 2 adjustments will have two components:

4.4.6.1 Adjustments to distribution expenses, and

4.4.6.2 Adjustments to the rate base in order to achieve sustainable levels of expenses and capital on a going-forward basis.

4.4.7 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.

4.4.8 Tier 2 adjustments should be applied on a prospective basis.

4.4.9 Approvals of proposed Tier 2 adjustments, or of any portion thereof, should be subject to monitoring, which should include:

4.4.10 The filing of monthly reports with the Board during the period of the approved expenditures.

4.4.11 Confirming that they have taken place as stated in the applicant's filing, or if not, providing an explanation and the applicant's revised plans.

4.4.12 If the Board determines that the applicant is departing materially from the Tier 2 adjustment proposals approved in its application, the Board should establish deferral accounts, including interest, to be used to ensure that the applicant's rates are adjusted appropriately for any such departures at the time of its next planned rate adjustment.

4.5 CME does **not** support Tier 2 adjustments that:

4.5.1 Include requests for hardship approved funding,

4.5.2 Would be 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.

4.5.3 Would be recovered with a rate rider to be in place for the period over which the corrective investments are to be undertaken.

Schedule 3-1: Tier 1 Adjustments

4.6 CME supports the proposal that applicants must:

4.7 Use Schedule 3-1 for all Tier 1 adjustments, except for non-routine/ unusual adjustments, for which Schedule 3-2 should be used.

4.8 Provide a breakdown of costs being claimed, if they include cost recoveries other than OEB annual dues.

4.9 Ensure that relevant information, sufficient to allow parties to the proceeding to have a full understanding of the adjustments, is included in its application.

Schedule 3-2: Tier 1 Non-routine / unusual Adjustments

4.10 CME supports the proposal that applicants must use Schedule 3-2 for all Tier 1 non-routine/ unusual adjustments and that these are mandatory were required.

Schedule 3-3: Tier 2 Adjustments

4.11 CME supports the proposal that applicants must:

4.11.1 Use Schedule 3-3 for all Tier 2 adjustments and that these are optional but to be eligible the applicant must:

4.11.1.1 Begin the 1999 RUD process with negative returns.

4.11.1.2 Not have received the second third of the MARR increment.

4.11.2 Confirm that the proposed additional capital expenditures or distribution expenses had to be postponed due to one or both of the reasons outlined in 4.11.1.1 and 4.11.1.2 above.

4.11.3 Provide the total dollar amount, per annum, of the impact on distribution expenses and capital of any proposed adjustments, and an explanation as to how the breakdown between the two accounts was determined, and why the resulting amounts are appropriate.

4.11.4 Provide, on a going-forward basis, breakdowns of the amounts proposed to be spent by Uniform System of Accounts (USoA) accounts, and information as to the specific projects to which they relate.

4.11.5 Provide this information in the following format, with the proposed timing specified on a monthly basis:

4.11.5.1 Capital programme adjustment requested in dollars, if any

4.11.5.2 Expense impacts adjustment in dollars, if any

4.11.5.3 Other impacts of proposed adjustment in dollars, if any.

4.11.6 Include a detailed explanation of the nature of the projects and the estimated timing.

4.11.7 If making additional hardship funding requests, provide the total dollar amount that is being requested, the prior years to which it relates, a per annum historic breakdown of the impact on distribution expenses and capital, and an explanation as to how the breakdown between these two amounts was determined and why it is appropriate.

4.11.8 Break down these amounts to specify in which of the prior years they would have been incurred, including identification of areas of under-spending of USoA accounts and information as to the specific projects to which they relate.

4.11.9 Provide, on a going-forward basis, breakdowns of the amounts proposed to be spent by USoA accounts, and information as to the specific projects to which they relate.

4.11.10 Provide this information in the following format, with the proposed timing specified on a monthly basis:

4.11.10.1 Capital programme adjustment requested in dollars, if any

4.11.10.2 Expense impacts adjustment in dollars, if any

4.11.10.3 Other impacts of proposed adjustment in dollars, if any.

4.11.11 Include a detailed explanation of the nature of the projects and the estimated timing.

5.0 Chapter 4 - Rate Base

CME's Position – Definition of Rate Base

5.1 CME supports the proposal that:

5.1.1 An applicant must file information on its 2004 total assets, broken down into "distribution" and "non-distribution" segments, with the level of detail as outlined in Schedule 4-1, Appendix B, and the 2006 EDR Model.

5.1.2 The "distribution" segment should be defined as:

5.1.2.1 That part of the business in which distribution activities are performed.

5.1.2.2 Assets that enable the conveyance of electricity for distribution purposes.

5.1.2.3 The operation and management of the distribution system, meter-reading services, billing and collection services, and similar activities.

5.1.3 "Non-distribution" assets are those associated with activities that would not be considered to be distribution activities, including street lighting services, renting and selling of hot water heaters, electricity transmission, and other services that do not satisfy the definition of distribution wires assets.

5.1.4 Appendix B outlines the relevant rate base accounts and provides information on how non-utility assets should be identified and removed. The nature of any such removals should be specified.

5.1.5 Appendix D, which contains the 2006 EDR Model, provides the details of these filing requirements.

5.1.6 Distributors wishing to have any assets included in the distribution rate base that would not be included in the definition of the distribution rate base, as specified in Appendix B (e.g. Account 1815 Transformer Station Equipment – normally primary above 50 kV), should request in their applications that the Board, in its decisions on their applications, deem such assets to be distribution assets.

5.1.7 All applicants must file rate base information for the years 2002, 2003, and 2004.

5.1.8 The rate base used to determine the revenue requirement is defined as net fixed assets at year-end.

CME's Position – Amortization Rates

5.2 CME supports the proposal that:

5.2.1 The amortization rates outlined in Appendix C, Amortization Rates, should be used for the purposes of the 2006 filing.

5.2.2 Applicants who do not use the amortization rates listed in Appendix C must justify this departure and file the amortization schedules they are proposing to use. The amortization study that supports those schedules should also be filed.

CME's Position – Capital Investments

5.3 CME supports the proposal that applicants should complete Schedule 4-1, Capital Expenditures, which provides details on their 2004 capital investment programmes.

CME's Position – Non-IT-Related Investments

5.4 CME supports the proposal that the materiality threshold for non-IT capital investments should be as set out in the following table.

Rate Base	Materiality Threshold ($ Value)	Materiality Threshold (% of Net Fixed Assets d)
Under $100 million	75, 000	0.2%
$100 million – $250 million	150, 000	0.2%
$250 million - $1 billion	300, 000	0.2%
Greater than $1 billion	500, 000	0.2%

5.5 The applicant should calculate each of the materiality thresholds applicable to its particular circumstances and use the lower of the two thresholds to determine its own applicable level of materiality.

CME's Position – IT-Related Investments

5.6 CME supports the proposal that:

5.6.1 Major capital expenditures related to IT initiatives (e.g. billing systems, Supervisory Control And Data Acquisition (SCADA) systems, asset management systems, integrated resource systems, and similar expenditures) should be disclosed on Schedule 4-1.

5.6.2 The materiality thresholds for disclosure of capital investments should be as outlined in the Table below.

Rate Base	Materiality Threshold ($ Value)	Materiality Threshold (% of Net Fixed Assets
Under $100 million	75, 000	0.2%
$100 million – $250 million	150, 000	0.2%
$250 million - $1 billion	300, 000	0.2%
Greater than $1 billion	500, 000	0.2%

5.6.3 An applicant should calculate each of the materiality thresholds applicable to its particular circumstances and use the lower of the two thresholds to determine its own applicable level of materiality.

CME's Position – Interest: Deferral Accounts and Construction Work in Progress (CWIP)

CME's Position – Deferral Accounts

5.7 CME supports the VECC proposal that:

5.7.1 The interest rate on deferral accounts should be based on short-term debt, except when the deferral account is so large that it may be difficult for a utility to obtain.

5.7.2 The relative size of the deferrals may be compared to the utility's rate base. Where the deferral account balance, as a ratio, exceeds 10% of rate base, it would be an indicator that the utility may be constrained in obtaining short-term debt for exclusive financing of the deferral accounts. In those cases, the Board may choose to allow the utility to use a 5 to 10 debt rate. (Evidence Of M. Greg Matwichuk, On Behalf Of Vulnerable Energy Consumers Coalition, December 13, 2004, pages 20 and 21)

CME's Position – Construction Work in Progress (CWIP)

5.8 CME supports the VECC proposal that the interest rate on CWIP should be based on an Allowance for funds used during construction (AFUDC), using the rate of return on rate base. (Evidence Of M. Greg Matwichuk, On Behalf Of Vulnerable Energy Consumers Coalition, December 13, 2004, page 17)

CME's Position – Capitalization Policy

4.4 CME supports the proposal that an applicant's capitalization policy should be outlined in the description of the application and be filed with the application, if such a document exists.

CME's Position – Contributed Capital

5.9 CME supports the proposal that:

5.9.1 Contributed capital collected by the electricity distribution utilities on or after January 1, 2000 is not to be included in rate base. No return is earned on contributed capital collected on or after January 1, 2000, and the associated amortization expense is not charged to operating expenses.

5.9.2 Historical contributed capital included in rate base under the Ontario Hydro regulatory regime should remain in rate base and should earn a return until these assets are fully depreciated. The depreciation expenses associated with this historical contributed capital should be charged to operating expenses until the assets are fully depreciated.

CME's Position – Non-depreciable Assets Sold to a Non-Affiliate

5.10 CME supports the proposal that the treatment of capital gains and losses on non-depreciable assets sold to a non-affiliate will be determined by the Board on a case-by-case basis, subject to a materiality threshold as set out in the Table below.

Rate Base	Materiality Threshold ($ Value)	Materiality Threshold (% of Net Fixed Assets
Under $100 million	75, 000	0.2%
$100 million – $250 million	150, 000	0.2%
$250 million - $1 billion	300, 000	0.2%
Greater than $1 billion	500, 000	0.2%

5.11 Capital gains and losses that fall below the materiality threshold should be shared between ratepayers and the shareholder on a 50:50 basis in determining the applicant's revenue requirement.

CME's Position – Depreciable Assets Sold to an Affiliate

5.12 CME supports the proposal that:

5.12.1 The treatment of capital gains and losses on depreciable assets sold to an affiliate will be determined by the Board on a case-by-case basis, subject to a materiality threshold as set out in the Table below.

Rate Base	Materiality Threshold ($ Value)	Materiality Threshold (% of Net Fixed Assets
Under $100 million	75, 000	0.2%
$100 million – $250 million	150, 000	0.2%
$250 million - $1 billion	300, 000	0.2%
Greater than $1 billion	500, 000	0.2%

5.12.2 Capital gains and losses that fall below the materiality threshold should be to the credit of the shareholder in determining the applicant's revenue requirement.

CME's Position –Assets Sold to an Affiliate

5.13 CME supports the proposal that:

5.13.1 The treatment of non-depreciable and depreciable assets sold to an affiliate is as outlined above for each of the representative circumstances, that is, non-depreciable or depreciable.

5.13.2 The materiality threshold, however, will be applied to the value of the asset sold and not to the amount of the gain or loss on the sale.

CME's Position –Schedule 4-1 Capital Expenditures

5.14 CME supports the:

5.14.1 Information requirements and format that applicants must file as set out in the draft Handbook.

5.14.2 The requirement that for any projects exceeding the materiality threshold, a detail summary of the project must be attached to the Schedule, outlining such key information as its purpose, its cost, its timing and other information relevant to the Board and other interested parties.

6.0 Chapter 5 - Cost of Capital

CME's Position

6.1 CME supports the proposal that:

6.1.1 The cost of capital should be defined as: the costs incurred by a utility in order to finance its operations, either by attracting and retaining investment from shareholders, or by raising debt and that it has three main components:

- **Return on equity (ROE):** the maximum return that shareholders should be able to earn, assuming operations are normal and managed prudently, and considering the risk of the market, firm, or sector

- **Debt rate (DR):** the cost of financing long-term debt, taking into account interest rates and the risk of the market, firm, or sector

- **Debt/equity ratio (D/E):** the proportion of the firm's financial structure that is financed through debt, the remainder being financed through equity

6.1.2 There should be no distinction between common shares and preferred shares, in equity.

6.1.3 Short-term debt should be ignored in the calculation of cost of capital.

6.1.4 The proposal that the cost of capital is the weighted average of the return on equity and the debt rate, as demonstrated in the following equation, where D is debt ratio, the percentage of the rate base that is (deemed) to be financed through debt; DR is debt rate; and ROE is return on equity:

$$\text{Cost of Capital} = D \; + (1\text{-}D) \times ROE$$

6.1.5 The debt rate and the maximum allowed return on equity should be updated for 2006 to reflect the forecast for the long-run (30-year) Government of Canada bond yield.

6.1.6 The equity risk premium should be held at 3.80% (380 basis points).

CME's Position - Maximum Return on Equity

6.2 CME supports the proposal that:

6.2.1 The maximum allowed return on equity should be based upon the initial set-up documented in Section 5 of Dr. Cannon's paper, "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities," December 1998.

6.2.2 The Board should determine the maximum allowed return on equity for 2006 using the most current data available at the time it releases its 2006 EDR decision.

CME's Position - Debt Rate

6.3 CME supports the proposal that:

6.3.1 The debt rate (DR) should be based upon the forecast of the Long Canada Bond Rate (LCBR), and be determined by the Board using the most current data available, at the time it releases its 2006 rate decision.

6.3.2 The deemed debt rate to be used for setting 2006 revenue requirements and rates should be based on the forecast Long Canada Bond Rate, with a size-related adjustment, as illustrated in the Table below.

Size-Related Debt Rate Formula							
Utility Size	Rate Base	Deemed Capital Structure		Deemed Debt Rate	δ_i	x	LCBR
		Debt (1 – CER)	Equity (CER)			0.60%	5.81%
Large	> $1.0 billion	65.00%	35.00%	6.41%	0.00%		
Medium - Large	$250 million - $1.0 billion	60.00%	40.00%	6.51%	0.10%		
Medium - Small	$100 million - $250 million	55.00%	45.00%	6.61%	0.20%		
Small	< $100 million	50.00%	50.00%	6.86%	0.45%		

6.3.3 The 2006 EDR Model should calculate the deemed debt rate based upon the utility's base rate.

CME's Position - Weighted average debt rate

6.4 CME supports the proposal that:

6.4.1 For debt held with a third party, the actual debt rate for that debt should be used.

6.4.2 For debt held with an affiliated firm (e.g. municipal share-holder, holding company), the debt rate used is the lower of the actual debt rate and the deemed debt rate at the time of issuance.

6.4.3 The debt rate should include all costs of issuance.

6.4.4 The weighted average debt rate is calculated in Schedule 5-1, using the methodology applied in the following example – Table 6-2.

Table 6-2: Weighted Debt Rate Calculation				
Organization Holding Debt	**Debt**	**Actual Debt Rate**	**Debt Rate Used (DR)**	**Reason**
Parent	$25 million	6.75%	6.75%	Debt issued to affiliate at time when Board's deemed rate was 6.75%: use lesser min (6.75%, actual)
Parent	$20 million	6.45%	6.45%	Affiliated: use min (6.75%, actual)
Bank	$20 million	6.90%	6.90%	Unaffiliated: use actual
Total:	$65 million	**Average:**	6.70%	

6.4.5 An applicant must submit copies of the debt instrument issued to affiliates to prove the issuance date, rate, term, and expiry.

CME's Position - Capital Structure

6.5 CME supports the proposal that:

6.5.1 Applicants should use the deemed debt/equity structure, as shown in Table 6-1, to establish the revenue requirement for 2006 distribution rates.

6.5.2 There should be no adjustment for short-term debt, and there should be no distinction made between common equity and preferred shares.

6.5.3 A utility must show in Schedule 5-2 its actual capital structure (debt/equity ratios) for 2004 based upon shareholders' equity, preferred shares, and debt. These numbers, typically, should be taken or derived from the utility's 2004 audited financial statements or similar records.

6.5.4 Where the actual debt/equity deviates from the deemed debt/equity structure, given the utility's size, by more than ten percentage points, the applicant must provide an explanation in Schedule 5-2 why the actual debt/equity structure is different.

CME's Position - Working Capital Allowance

6.6 CME supports the proposal that:

6.6.1 Working capital allowance (WCA) represents the estimated cash flow required by the distributor to be paid in advance of recovery and that it should be included in the calculation of the rate base upon which the distributor may earn a return.

6.6.2 For 2006 rates, the allowance is calculated at 15% of the "distribution segment only" cost of power, and other power supply expenses and controllable expenses. The general ledger accounts to be included in the working capital allowance should be set out in Appendix B, Table B.2

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

6.7 CME does **not** support the proposal that:

6.7.1 The historical cost of power should be adjusted to better reflect the actual costs expected to be incurred, or,

6.7.2 If the forecast cost of power is not available distributors be permitted to track the difference between the estimated and the actual cost of power in a variance account.

CME's Position – Schedule 5-1: Weighted Average Cost of Capital

6.8 CME supports the:

6.8.1 Information requirements and format of Schedule 5-1 set out in the draft Handbook.

6.8.2 In column (8) of Schedule 5-1, the comparison between the actual rate and the deemed rate should be made using the deemed debt rate shown in Table 6-1 of this submission. For debt held by an unaffiliated third party, use the actual Debt Rate.

7.0 Chapter 6 - Distribution Rates and Expenses

CME's Position - General requirement for three years of supporting data

7.1 CME supports the proposal that:

7.1.1 All applicants must file distribution expenses for the years 2002, 2003, and 2004.

7.1.2 Significant variances in the level of expenses between years should be explained in the description of the application. Circumstances which may affect the comparability of any of the three years of cost data filed, such as a change in accounting policies, should be also be explained in the description.

7.1.3 Distribution expenses data should be entered on *Tab_ Trial Balance of the 2006 EDR Model* and displayed and totalled on the Distribution Expense Sheet.

CME's Position - Definition of distribution expenses

7.2 CME supports the proposal that:

7.2.1 Only those expenses associated with activities that enable the provision of distribution services will be allowed for calculation of the applicant's 2006 revenue requirements.

7.2.2 Distribution expenses be filed in aggregated groupings for 2002, 2003, and 2004, and separated into distribution and non-distribution amounts in the Trial Balance of the 2006 EDR Model.

7.2.3 Appendix E should list the APH accounts considered to be distribution expenses for purposes of determining 2006 revenue requirements.

CME's Position - Detailed Reporting for Specific Distribution Expenses

7.3 CME supports the proposal that in order to review the reasonability of some specific distribution expenses requires disclosure of information.

CME's Position - Insurance Expense – Minimum Filing Requirements

7.4 CME supports the proposal that:

7.4.1 All applicants must file insurance expenses recorded for the years 2002, 2003, and 2004.

7.4.2 For utilities with third party insurance, the applicant must provide the following additional data:
7.4.2.1 Number of insurers
7.4.2.2 Type of insurance purchased
7.4.2.3 Premium cost per type of insurance.

7.4.3 For those with self-insurance:
7.4.3.1 Insurance expenses must consist of self-funded claims and any changes in reserves recorded as expense.
7.4.3.2 Information about the organization and the operation of the self-insurance plan must be provided in the description of the application.

7.4.4 Where distributors self-insure, information about the organization and the operation of the self-insurance plan must be provided in the description of the application.

CME's Position – Recovery of Self-Insurance Costs

7.5 CME supports the proposal that while actual expenses for self-insured claims are allowable for calculation of the 2006 revenue requirement, any change in reserve(s) for self-insurance are not to be included in the 2006 revenue requirement.

CME's Position - Bad Debt Expense – Minimum Filing Requirements

7.6 CME supports the proposal that:

7.6.1 All bad debt expense as reported in Account 5335 for the years 2002, 2003, and 2004, should be reported and segregated by customer class.

7.6.2 Disclosure of all individual material bad debt occurrences should be included in the 2004 bad debt expense, as recorded in Account 5335.

7.6.3 Disclosure should include the dollar value of the bad debt occurrence and a brief explanation of the circumstances.

7.6.4 Materiality should be defined as, an amount exceeding 0.2% of the total 2004 distribution expenses. The applicable materiality value should be calculated automatically within the 2006 EDR Model.

7.6.5 Applicants should explain in the description of the application the rationale behind including all or part of a material 2004 bad debt occurrence (e.g. bankruptcies) in the 2006 revenue requirement.

CME's Position - Information Technology Expenses

7.7 CME supports the proposal that in the description of the application, the applicant must include a description of its internal organization for it internal and contracted out IT services, and its methodology of recording IT expenses.

CME's Position - Advertising expenses

7.8 CME supports the proposal that:

7.8.1 Advertising expenses incurred for the sole purpose of promoting corporate branding or image should **not** to be included in determining the applicant's 2006 revenue requirement.

7.8.2 At a minimum, applicants must review their 2004 expense data to identify and disclose such amounts as non-recoverable.

CME's Position - Political contributions

7.9 CME supports the proposal that:

7.9.1 Political contributions in the form of cash donations to political parties are **not** to be included in determining the applicant's 2006 revenue requirement.

7.9.2 At a minimum, applicants must review their 2004 expense data to identify and disclose such amounts as non-recoverable.

CME's Position - Employee dues

7.10 CME supports the proposal that:

7.10.1 Annual fees or dues for employee memberships in organizations that are recreational or social in nature are **not** to be included in determining the applicant's 2006 revenue requirement.

7.10.2 Employee dues or fees related primarily to health and fitness are recoverable, provided that the same are generally available to all categories of employees.

7.10.3 At a minimum, applicants must review their 2004 expense data to identify and disclose such amounts as non-recoverable.

CME's Position - Charitable contributions

7.11 CME supports the proposal that:

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

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

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

7.12 CME supports the proposal that **no** charitable contribution expenses shall be included in the determination of the applicant's 2006 revenue requirement.

CME's Position - Meals/travel and business entertainment expenses

7.13 CME supports the proposal that:

7.13.1 Applicants must indicate in the description of the application whether or not it has a written meals/travel/entertainment policy, including any collective agreement(s) that sets out guidelines for management approval of meals, travel, and business entertainment expenses.

7.13.2 Applicants must confirm, also in the description of the application, that internal measures exist to ensure that staff meals, travel, and entertainment-related expenses included in the filing, were approved by the applicant's management, based upon a consistently applied corporate policy.

7.13.3 An applicant must file a copy of its written policy for employee expenses in relation to meals, travel, and business entertainment.

CME's Position - Research and development

7.14 CME supports the proposal that:

7.14.1 Research and development expenditures intended to benefit the applicant's ratepayers will be included in the determination of the of the applicant's 2006 revenue requirement.

7.14.2 The description of the application should provide an explanation of the nature and amounts of such expenditures, and how they will benefit the applicant's ratepayers.

CME's Position - Review of Employee Total Compensation

7.15 CME supports the proposal that:

7.15.1 Applicants must demonstrate that the total compensation paid to its employees, part of which may be capitalized rather than expensed, is reasonable for recovery in the calculation of 2006 revenue requirements.

7.15.2 Total compensation includes:

- Base salary or wages earned
- Overtime premiums paid
- Value of benefits received that are paid for by the employer
- Performance incentive payments received

7.15.3 To review the reasonableness of the applicant's total compensation expense, information is required on the number of employees and on compensation levels, and should be provided in *Tab_ Employee Compensation in the 2006 EDR Model*.

7.15.4 Applicant must provide three years of historical data (2002, 2003, and 2004) for the following four broad categories of distributor employees and contract workers:

- Executive: CEO, COO, VP(s), General Manager(s), Director(s)
- Management: operational, middle, and supervisory managers
- Non-unionized: positions not included in union bargaining units that have no supervisory or management responsibilities
- Unionized: positions that are part of a union bargaining unit

7.15.5 Where there are three, or fewer, full-time equivalents (FTEs) in any category, the utility may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs.

7.15.6 For a given applicant, where the total number of employees 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.

7.15.7 The information to be disclosed in aggregate for each category of employees is as follows:

- Average yearly wage
  - Segregated into base wage and overtime
  - Wage: all earnings, excluding incentive and benefits, which are to be reported separately.
- Average yearly incentive
  - Incentive: Those amounts paid on a corporate incentive or bonus plan
- Average yearly benefits
  - Benefits: Those amounts the applicant deems as employee benefits related to compensation
- Number of full-time equivalents (FTEs)

7.15.8 In addition to aggregated salary disclosure, total compensation for each distributor employee earning more than $100,000 per annum must be reported separately and individually.

CME's Position - Incentive plans

7.16 CME supports the proposal that:

7.16.1 Incentive payments that provide immediate benefits primarily to the shareholder should not eligible as a distribution expense in the approved 2006 revenue requirements, and must be considered non-recoverable.

7.16.2 Applicants with incentive compensation plans must file the following information in Schedule 6-1:

- Details of the incentive compensation plan(s)
  - A description of the performance measures
- The total annual dollar value of incentive compensation
  - A breakdown the shareholder-related component and the ratepayer-related component separately.

CME's Position - Pensions and Post-retirement Benefits

7.17 CME supports the proposal that applicants whose employees are:

7.17.1 Members of the Ontario Municipal Employees Retirement System (OMERS) pension plan must provide OMERS pension premiums and adjustments expense for the years 2002, 2003, and 2004 on *Tab Specific Distribution Expenses in the 2006 EDR Model*.

7.17.2 Not members of OMERS:

7.17.2.1 May fund and administer their own pension plans and may incur pension expenses.

7.17.2.2 Including those with distributor-owned and administered pensions, must provide the following information in Schedule 6-2:

- Cash versus accrual valuation
- "Smoothing" methods
- Eligibility by employee groups
- Summary of performance for each plan

7.18 CME also supports the proposal that:

7.18.1.1 Expenses recorded for post-retirement benefits, if reasonable, should be allowed for recovery in the 2006 revenue requirement.

7.18.1.2 Applicants must provide the following information in the description of the application:

- Current accounting treatment of post-retirement benefits
  - e.g. cash versus accrual
  - e.g. review period frequencies

- Treatment of past changes in accounting policy regarding post-retirement benefits, and any related one-time expenses, including amortization policy
  - e.g. change from cash basis, to accrual basis
- Treatment of changes in actuarial value in post-retirement benefits
- Disclosure of any plans not to follow the current CICA accounting rules for regulatory purposes, and explanation for the alternative treatment

CME's Position - Distribution Expenses Paid to Affiliates

7.19 CME supports the proposal that:

7.19.1 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.

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

7.19.3 Where reported distribution expenses are incurred through affiliate transactions, the following information must be included in Schedule 6-3:

- Identity of each affiliate transacting with the utility
- 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

7.19.4 Actual costs of the affiliate, where cost-based pricing was used for services or goods provided by the affiliate to the utility. A description of the process for establishing the absence of a market, before using cost-based pricing.

7.19.5 To help justify the reasonableness of amounts paid to affiliates for purposes of 2006 distribution rates, applicants must provide a general explanation of Schedule 6-3 on how they followed the transfer pricing and shared service rules in the Affiliate Relationships Code.

Where a distributor fails 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 should specifically review the reasonableness of allowing full recovery of the amounts paid in the given circumstances.

7.19.6 Where distribution expenses are incurred through the sharing of services or resources with affiliates, the following information must be included in Schedule 6-3:

- Types of services: finance, IT, office space, etc.

- Total annual dollar value, by service
- Rationale and summary of cost allocators used for shared costs, for each type of service: square footage, computers, headcount, etc.

CME's Position – Schedule 6-1: Employee Incentive Plan Expense

7.20 CME supports the information requirements and format of Schedule 6-1 set out in the draft Handbook.

CME's Position – Schedule 6-2: Non-OMERS Pension Expense

7.21 CME supports:

7.21.1 The information requirements and format of Schedule 6-2 set out in the draft Handbook.

7.21.2 The information provided for 2002 and 2003 must be consistent with the general provision of three years of historical data.

CME's Position – Schedule 6-3(a): Distribution Expenses Paid to Affiliate(s)

7.22 CME supports:

7.22.1 The information requirements and format of Schedule 6-3(a) set out in the draft Handbook.

7.22.2 The proposal that: if cost-based pricing was followed, the applicant should explain if, and how, the absence of a market was established.

7.22.3 The proposal that: where cost-based pricing was used for the service of goods, provided by the affiliate(s) to the applicant, list the actual costs of the affiliate.

CME's Position – Schedule 6-3(b): Distribution Expenses Incurred Through Sharing Services with Affiliate(s)

7.23 CME supports:

7.23.1 The information requirements and format of Schedule 6-3(b) set out in the draft Handbook.

7.23.2 The proposal that: the applicant must provide a general explanation of how they followed the transfer pricing and shared services rules in the Affiliate Relationships Code.

8.0 Chapter 7 - Taxes / PILs

CME's Position - Rules and Principles

8.1 CME supports the proposal that:

8.1.1 The 2006 tax filing guidelines are to allow recovery of the distribution-only tax payable expected to be incurred by the distributor.

8.1.2 The 2006 EDR Model and its principles will only be applicable to the 2006 rate year.

8.1.3 The Board has decided that rebasing will be allowed in 2008, and so it is assumed that the tax model and its principles will be revisited as part of future rates processes no later than 2008.

8.1.4 This tax model has not been designed for a distributor using a forward test year.

CME's Position - Rules and Principles

8.2 CME supports the following principals:

8.2.1 Most Ontario distributors will pay income and capital taxes in the form of section 93 proxy tax payments (PILs) to the Province. A small number of distributor(s), however, may pay section 89 proxy taxes, or as taxable corporations be subject to normal provincial and federal taxation.

8.2.2 A distributor required to pay PILs under section 93 of the Electricity Act must compete the 2006 OEB Tax Model without amendments.

8.2.3 Any distributor submitting its own tax filing calculation, as well as the 2006 OEB Tax Model, must, in that separate calculation, follow the same basic principles and level of detail outlined in the 2006 Handbook and set forth in the 2006 OEB Tax Model. Any variations from the 2006 OEB Tax Model must be identified and described in the description of the application.

8.2.4 Distributors not required to pay PILs under section 93 must do the following:

- Describe in the description of the application the basis of their tax or PILs payments
- Complete the 2006 OEB Tax Model with such changes as are necessary, while remaining consistent with the principles and the level of detail outlined in this 2006 Handbook
- Explain all such changes to the 2006 OEB Tax Model in the description of the application

8.2.5 All distributors are expected to take prudent steps to manage their tax costs with reasonable diligence, as with other distribution expenses.

8.2.6 The tax amount included in rates is based upon taxes expected to actually payable as a result of operating the distribution-only business, rather than upon taxes calculated for accounting purposes. Future/deferred taxes will not be recovered through rates as a result of this filing.

8.2.7 The 2006 OEB Tax Model estimates regulatory taxes payable. It takes into account the standard format of corporate tax returns to be submitted to tax authorities.

8.2.8 Revenues, expenses, capital items, and all other operating numbers should be calculated using the 2006 EDR Model, based upon 2004 historical data, plus or minus allowed or required adjustments.

8.2.9 The 2006 OEB Tax Model starts with these results, then requires specific additional adjustments to project the PILs expected to be payable in 2006. The 2006 OEB Tax Model automatically includes data from the 2006 EDR Model.

8.2.10 The 2006 OEB Tax Model and the 2006 Handbook guidelines relating to PILs are based upon tax rates and rules that, as of April 1, 2005, are reasonably expected by the Board to be in effect during the 2006 rate year.

PILs tax administration and tax rulings

8.2.11 If there are any changes to tax rates or rules after April 1, 2005 and prior to filing the 2006 OEB Tax Model that should be incorporated into the distributor's tax calculations, the Board will issue a supplementary communication to that effect, amending the 2006 OEB Tax Model and/or the guidelines in the 2006 Handbook.

8.2.12 To calculate the tax payable/recovery to be allowed in the 2006 revenue requirement, distributors must follow the Board's regulatory tax principles set out in the 2006 Handbook and in the 2006 OEB Tax Model.

8.2.13 If a specific tax ruling or assessment policy applies to the distributor in a manner inconsistent with the 2006 OEB Tax Model, a summary of the ruling/policy shall be disclosed in the description of the application. The applicant's initial 2006 tax payable filing should account for the tax effect of the ruling or policy.

8.2.14 As part of the application's approval, the Board will determine whether to approve any suitable variation in the regulatory tax calculation.

True-up of 2006 actual taxes paid to taxes recovered in rates

8.3 CME supports the proposal for a partial true-up, inclusive of tax rate/tax law/assessing policy changes and reassessments as follows:

8.3.1 Each distributor shall 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 ministries, if the Board has declared at that time 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

8.3.2 Differences between actual taxes paid in 2006, and taxes recovered in rates resulting from any causes other than the three enumerated above, will not be credited or debited to the 2006 PILs/taxes variance account. The differences that will not be trued-up will include, but be limited to, the following:

- Any differences resulting from actual earnings being greater or less than the forecast earnings for the rate year
  - Shareholders will, in effect, bear the incremental tax associated with over-earnings
  - Shareholders will have the benefit of the reduced tax cost associated with under-earnings

- Any differences resulting from the actual mix of expenses, capital expenditures, or other components of the calculation of net income or taxable income being different from the mix assumed in the 2006 EDR Model and/or 2006 OEB Tax Model

8.3.3 The above rules apply only to the 2006 PILs/taxes variance account. The 2007 PILs/taxes variance account will be dealt with in subsequent Board communication.

Principles Applicable to Specific Components of the Calculation

Regulatory assets

8.4 CME supports the proposal that recovery of PILs will not be allowed to the distributor with respect to PILs on regulatory assets and that:

8.4.1 All regulatory assets recoveries, therefore, that are included in projected 2006 net income (line ***XX*** of the 2006 EDR Model) must be deducted on line ***XX*** of the 2006 OEB Tax Model.

8.4.2 Parallel adjustments for any regulatory liabilities must be made at line xx of the 2006 OEB Tax Model.

Regulatory treatment of associated reduction in actual taxes payable in respect to non-recoverable or disallowed expenses:

8.5 CME supports the proposal that the total amount of expenses non-recoverable/disallowed for regulatory purposes, but deductible for tax purposes, should be entered on line **XX** of the 2006 OEB Tax Model. This has the effect of allocating all the tax savings generated by such expense to the ratepayers.

Eligible Capital Expenses (ECE):

8.6 CME supports the proposal that with respect to eligible expenses distributors:

8.6.1 Must claim maximum amortization of ECE in computing taxes payable for purposes of the 2006 OEB Tax Model.

8.6.2 To the extent that the adjustment in fair market value at October 1, 2001 is included in the UCC and in the Cumulative Eligible Capital Amounts or Disallowed Expense, the value of such adjustments for the PILs calculations, will be allocated to the ratepayer.

8.6.3 With respect to disallowed expenses, such as goodwill, and other intangible assets, disallowed for regulatory purposes the value of such adjustments for the PILs calculations, will be allocated to the ratepayer.

Charitable donations

8.7 CME supports the proposal that with respect to disallowed charitable expenses that 100% of the tax saving should be to the account of the ratepayer.

Sharing of tax exemptions

8.8 CME supports the proposal that to provide an over-all sharing of tax exemptions between a corporate group of which the distributor is a member, or within a single corporate entity that provides both wires and non-wires services, do the following when completing the 2006 OEB Tax Model:

8.8.1 If the distributor is the only regulated utility in the corporate group, all the federal Large Corporation Tax (LCT) exemption shall be allocated to the distributor.

8.8.2 If the distributor is a member of a larger corporate group that includes other regulated utilities, the corporate group must allocate the federal Large Corporation Tax (LCT) exemption for 2006 to the distributor and other regulated entities within the corporate group, if any, on a reasonable basis, which basis must be disclosed on Sheet XX.

8.8.3 No amount of the LCT exemption shall be allocated to an unregulated member of the corporate group.

8.8.4 If the distributor is a member of a larger corporate tax group, the corporate group must allocate the 2066 provincial capital tax exemption, including both regulated and unregulated entities.

8.8.5 For tax purposes, that the provincial capital tax exemption be pro-rated within the corporate group, based upon paid-up capital amounts.

8.8.6 Applicants that do not anticipate significant changes in corporate capital mix can use their expected 2004 allocation as a proxy. Other applicants must file Schedule 7-1 in which they must explain and justify their choice of allocation.

8.8.7 When distribution and non-distribution functions are being undertaken in the same legal entity, as expressly contemplated under the current and future regulatory regime, then the federal LCT exemption and provincial capital tax exemptions assigned to a regulated legal entity under the entries i.) and ii.), above, should be further pro-rated to reflect the relative asset values used in the electricity wires activities, as opposed to other activities.

8.8.8 Schedule 7-1 must include an explanation of this calculation.

Loss carry-forwards

8.9 CME supports the proposal that:

8.9.1 Distributors expecting to have loss carry-forwards still available on January 1, 2005 must disclose the amount of those loss carry-forwards, project the amount that will still be available on January 1, 2006, and apply them in full to reduce the taxable income to be included in the 2006 OEB Tax Model.

8.9.2 Schedule 7-2 must be filed.

8.9.3 The projection shall be based upon the following:
- The actual loss carry-forwards, as of January 1, 2005
- An estimate of any additional losses, or application of losses, in 2005
- A resulting estimate of the loss carry-forward remaining on January 1, 2006

8.9.4 Any stub period from January 1 through April 30, 2006 must be ignored. It will be assumed that any loss carry-forwards available on January 1, 2006 will still be available on May 1, 2006.

8.9.5 If a distributor has within its legal entity a business other than a distribution business, loss carry-forwards must be allocated between the distribution and the non- distribution business on a reasonable basis.

8.9.6 The applicant's loss carry-forward Schedule 7-2 filed must include a description and justification of that allocation method and calculation.

Loss carry-backs

8.10 CME supports the proposal that no adjustment for loss carry-backs be permitted, since the OEB Tax Model estimates 2006 PILs.

Amortization of tangible assets and capital cost allowance (CCA)

8.11 CME supports the proposal that:

8.11.1 Maximum CCA must be claimed when computing taxes payable for purposes of the 2006 OEB Tax Model.

8.11.2 The following steps must be taken for the purpose of determining amortization of tangible assets (depreciation) and CCA in 2006:

Add-back:

8.11.2.1 The distributor should add back the wires-only amortization amount, including Tier 1 adjustments, included in the 2006 EDR Model.

Deduction:

8.11.2.2 The 2005 opening balance must be the same as the closing 2004 balance for each class adjusted to remove all impacts of the 2001 Fair Market Value (FMV) Bump.

8.11.2.3 The value of assets at October 1, 2001 for regulatory purposes is book value.

8.11.2.4 The Ministry of Finance required an increase in value at October 1, 2001 for tax purposes only. To the extent that the adjustment in fair market value at October 1, 2001 is included in the UCC, the value of such adjustments must be excluded from these accounts for the PILs calculation.

8.11.2.5 These adjustments will be factored into Schedules **XX** and **XX** with appropriate instructions.

8.11.2.6 The applicant must then assume that it has new additions to each class in 2005 equal to the following:

- The capital expenditures (i.e. new additions) to each class in 2004
- Any Tier 1 and Tier 2 allowed capital adjustments relating to 2005, such as transformer stations, to the extent that they are higher than the 2005 additions used above

8.11.2.7 The half-year rule must be applied to the calculation of CCA for all of the new additions in 2005.

8.11.2.8 After adding these new additions, 2005 CCA must be calculated and deducted, resulting in the new Un-depreciated Capital Cost (UCC) as of January 1, 2006.

8.11.2.9 The distributor must then assume that it has new additions to each class in 2006 equal to the new additions in 2005 - plus incremental Tier 1 and Tier 2 adjustments relating to 2006, if any are permitted - and add them to get the Reduced UCC before CCA. Apply the half-year rule to 2006 additions.

8.11.2.10 The steps above must be documented in Sheet **XX** of the 2006 OEB Tax Model.

Interest deduction

8.12 CME supports the proposal that interest deducted in computing the 2006 tax calculation must be the same as that allowed for recovery in the 2006 rates, as established in Chapter 5 of the Handbook.

Overlapping year-ends

8.13 CME supports the proposal that:

8.13.1 In order to calculate the approved regulatory tax payable for the 2006 rate year, however, the rate year will be assumed to be the same as the tax year. Any stub period issues, therefore, (e.g. loss carry-forwards or CCA) must be ignored when completing the 2006 OEB Tax Model.

8.13.2 The only exception to this principle is in the tax rates to be applied. All changes to tax rates anticipated during the 2006 rate year, at the time that the 2006 Handbook is issued, have been taken into account by simple pro-ration, ignoring income, in the rates built into the 2006 OEB Tax Model. No further action by distributors is required.

Estimating taxable capital

8.14 CME supports the proposal that:

8.14.1 In order to calculate 2006 regulatory Ontario Capital Tax and the federal LCT, the applied-for 2006 rate base (see *XX* 2006 RAM) should be used as the proxy for taxable capital. The intention is to allow a reasonable regulatory estimate of the tax payable, but not require distributors to forecast fully their 2006 balance sheets.

8.14.2 The applicant should have the option of substituting its estimated 2006 taxable capital for the rate base proxy. In such cases, the following information must be provided:

- Full details of the capital tax calculation, including balance sheet assumptions
- The estimate calculated using rate base as a proxy

Ontario Corporate Minimum Tax

8.15 CME supports the proposal that the 2006 regulatory tax calculation does not include the Ontario Corporate Minimum Tax. As this Tax can be carried forward for ten years, the distributors should recover this tax as they become taxable.

Non-distribution elimination

8.16 CME supports the proposal that sheets *XX* of the 2006 OEB Tax Model require that the applicant exclude any non-wires costs and revenues. This elimination should be consistent with the definition of wires-only activity contained within the 2006 Handbook.

Tax credits

8.17 CME supports the proposal that back-up calculations must include an express estimate of any tax credits to be claimed in 2006, such as research and development credits.

Interest capitalised for accounting, but deducted for tax purposes

8.18 CME supports the proposal that the applicant must identify any interest capitalized for accounting, but deducted in 2004. That amount must be entered on line xx on Sheet xx. Any amount of capitalized interest that is not recoverable from rate payers must be dealt with in the same manner as described in section on interest deduction.

Property taxes

8.19 CME supports the proposal that distributors should be allowed to claim recovery of property taxes payable, including any "proxy" property taxes. Property tax expense is part of the other distribution expenses included in the main 2006 EDR Model (see line *XX* of that model).

Tax Payable Filings
2006 Minimum Information

8.20 CME supports the proposal that:

8.20.1 All applicants must file the following minimum information with respect to taxes in their 2006 rate filings:

- Audited financial statements for the years 2002, 2003, and 2004
- Taxes actually paid for the years 2002, 2003, and 2004 (estimated) with respect to the distribution business of the applicant

8.20.2 The description of the application must include a description of any variances between taxes actually paid in 2004, and the tax payable sought to be recovered in 2006 distribution rates, where such variances exceed 25% of 2004 taxes actually paid.

Future Tax Information Disclosure

8.21 CME supports the proposal that:

8.21.1 As part of its future filing, the distributor will be required to disclose the actual corporate PILs/taxes paid in 2006 and the amount collected in 2006 distribution rates.

8.21.2 If the difference between the two amounts is greater than 10%, that difference must be explained in that future filing.

8.21.3 Distributors shall keep appropriate records of the actual, versus the recovered, PILs/taxes for 2006, and the reasons for any differences.

Supporting Documentation

8.22 CME supports the proposal that where disclosure is not requested as part of the initial filing, applicants should still maintain reasonable supporting documentation in case enquiries are made during the regulatory review process.

CME's Position – Schedule 7-1: Sharing of Tax Exemptions

7.24 CME supports the information requirements and format of Schedule 7-1 set out in the draft Handbook.

7.25 CME does **not** support the proposal that the LCT exemption should not be prorated.

CME's Position – Schedule 7-2: Sharing of Loss Carry-Forwards

7.26 CME supports the information requirements and format of Schedule 7-1 set out in the draft Handbook.

9.0 Chapter 8 - Revenue Requirement

CME's Position – Service Revenue Requirement

9.1 CME supports the proposal that:

9.1.1 A utility's service revenue requirement is derived as follows: Service Revenue Requirement = {Rate Base X Cost of Capital} + Distribution Expense + PILS

9.1.2 The 2006 service revenue requirement is based on costs incurred during 2004, plus or minus Tier 1 and Tier 2 adjustments to rate base and distribution expenses.

CME's Position – Service Revenue Requirement and Base Revenue Requirement

9.2 CME supports the proposal that:

9.2.1 Before the service revenue requirement can be allocated, it is necessary to remove amounts that will be collected from regulated charges and other sources of revenue.

9.2.2 The service revenue requirement net of these revenue offsets is the base revenue requirement.

9.2.3 The applicant must complete Schedule 8-1 to derive the base revenue requirement. Except where specified otherwise, the cost allocation and rate design in Chapters 9 and 10 achieves the recovery of the base revenue requirement.

9.2.4 Two sources of revenue are to be removed as revenue offsets:

9.2.4.1 Revenue derived from regulated charges applicable to distribution customers (including embedded distributors where applicable) and to retailers.

9.2.4.2 The amount of the first offset is the sum of the amounts to be reported in Schedules 11-3 and 12-1. The first offset would generally be recorded in USoA Accounts 4225 and 4235, and, if applicable, in Accounts 4080, 4082, and 4084. The charges that determine this revenue offset are the subject of Chapters 11 and 12 of the Handbook.

9.2.4.3 Host distributors must also include revenue derived from LV charges, found in Schedule 10-8.

9.2.4.4 Revenue to the distributor from any source other than regulated rates and charges, such as rental of facilities owned by the distributor, interest on bank accounts, and other incidental sources.

9.2.4.5 The applicant must report its 2004 revenue from other sources in Schedule 8-1. Generally, this component is calculated as the sum of the amounts in USoA accounts 4205-4415, except for accounts 4225 (late payment charges) and 4235 (Miscellaneous Revenues). If any of these accounts contains revenue from Board-approved rates and charges that is included in Schedule 11-3, the applicant must adjust the amounts in Schedule 8-1 to avoid double counting of revenues.

9.2.4.6 Two Tier 1 revenue adjustments may be applicable to the amounts recorded in Schedule 8-1:

9.2.4.6.1 First, if the applicant is a host distributor, there may be revenue anticipated from embedded distributors in 2006 that differs from the revenue in 2004. The revenue offset to be used is the expected 2005 revenue, and should be included in Row 3.

9.2.4.6.2 Second, if there were unusual and non-recurring events in 2004 that produced revenue, exceeding a materiality threshold of 2% of total revenue offsets, an adjustment may be made in Schedule 8-1. If the adjustment is in row 2 or row 3, an explanatory note must be included in Schedule 8-1. If the adjustment is in row 4, the corresponding adjustment must be made to the relevant row in Schedule 8-2, with an explanatory note added to Schedule 8-2.

9.2.4.7 Other adjustments that would affect the revenue a distributor will collect in 2006 are made as load adjustments in Chapter 9. These include gain or loss of a major customer and adjustments for load loss due to C&DM programmes.

CME's Position – C&DM, Smart Meter, and Regulatory Asset Amortization Revenue

9.3 CME supports the proposal that:

9.3.1 The applicant must provide the C&DM revenue requirement, consisting of C&DM program expenses in 2006, net of those costs that have been retrieved as part of the third tranche of the market-adjusted rate of return in 2005 in…*to be determined.*

9.3.2 The applicant must provide the Smart Meter revenue requirement amount in…*to be determined*.

9.3.3 The costs of regulatory asset amortization will also be allocated on a different basis that the allocation applied to the base revenue requirement. The applicant must provide in Schedule 8-3 information about all regulatory assets that will be amortized (fully or partly) in 2006.

CME's Position – Schedule 8-1: Derivation of Base Revenue Requirement

9.4 CME supports the information requirements and format of Schedule 8-1 set out in the draft Handbook.

CME's Position – Schedule 8-2: Revenue from Sources other than Board-Approved Rates and Charges

9.5 CME supports the information requirements and format of Schedule 8-2 set out in the draft Handbook.

CME's Position – Schedule 8-3: Regulatory Asset Amortization

9.6 CME supports the information requirements and format of Schedule 8-3 set out in the draft Handbook.

10.0 Chapter 9 - Cost Allocation

CME's Position – Customer Classes

10.1 CME supports the proposal that:

10.1.1 For 2006, the respective class distribution revenue requirements should continue at approximately the same proportions of the total distribution revenue requirement, as in the initial design.

10.1.2 Distributors should retain the existing rate class definitions in 2006, as outlined in Appendix A because any change to customer groupings would require support from a cost allocation study.

10.1.3 If a distributor proposes to make any change to its customer classifications, sub-classes, or groups - that is, if the rate class, sub-class, or group definitions currently in use are not suitable for use in 2006, or if the definitions are to be applied differently in 2006, compared to the current practice - the distributor must complete and file Schedule 9-1, together with a detailed explanation and justification for the proposed change.

10.1.4 A distributor who has a customer whose maximum billing demand is greater than 50 kW, but who is classified in the <50 kW sub-class, and is therefore billed on kWh. In 2006, the distributor will continue its existing practice with respect to the classification of this customer.

CME's Position – Determination of the Appropriate Share of the 2006 Revenue Requirement for Each Class, Sub-Class, or Group

10.2 CME supports the proposal that:

10.2.1 Each distributor must complete and file Schedule 9-2 as part of its application.

10.2.2 If a distributor proposes to make any change to the rates, charge determinants, or resulting allocation factors based upon the preceding methodology, it must complete and file Schedule 9-3, together with a detailed explanation and justification for the proposed change.

10.2.3 These class, sub-class, or group proportions should then be applied to the base revenue requirements, as determined in Chapter 8.

10.2.4 The resulting amount of money required from a given class, sub-class, or group used in the determination of the 2006 distribution rates is the sum of the class's, sub-class's, or group's proportional share of the base revenue requirement, plus its allocated share of the other costs.

10.2.5 The spreadsheet model in Appendix D outlines the approach that should be used.

10.2.6 A change in the charge determinants is a change in the average load as a result of Tier 1 load adjustments.

Gain or loss of a major customer

10.2.6.1 If the revenue from a major customer that provided a material proportion of distribution revenue in 2004 will not be available in 2006, the amount of the load lost must be taken into account when completing Schedule 9-3. Similarly, if revenue from a major new customer will be gained in a material amount in 2006, the amount of the new load is to be taken into account when completing Schedule 9-3.

C&DM programme impacts

10.2.6.2 If the applicant has C&DM 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.

Smart Meter programme impacts

10.2.6.3 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.

10.2.6.4 These class, sub-class, or group proportions are then applied to the base revenue requirements, as determined in Chapter 8

10.2.6.5 The resulting amount required from a given class, sub-class, or group used in the determination of the 2006 distribution rates is the sum of the class's, sub-class's, or group's proportional share of the base revenue requirement, plus its allocated share of the other costs.

CME's Position – Determination of the Appropriate Share of the 2006 C&DM, Smart Meter, and Regulatory Asset Revenue Requirement

10.3 CME's position with respect to C&DM is set out in section 23.

CME's Position – Schedule 9-1: Customer Classification

10.4 CME supports the information requirements and format of Schedule 9-1 set out in the draft Handbook.

CME's Position – Schedule 9-2: Allocation Factors to Customer Classifications

10.5 CME supports the information requirements and format of Schedule 9-2 set out in the draft Handbook.

CME's Position – Schedule 9-3: Non-Default Allocation Factors to Customer Classifications

10.6 CME supports the information requirements and format of Schedule 9-3 set out in the draft Handbook.

11.0 Chapter 10 - Rates and Charges

CME's Position – Fixed/Variable Split

11.1 Pending the cost allocation studies that will be available during the 2007 rate process, CME supports the proposal that:

11.1.1 For each class, sub-class, or group, the rate is composed of two components:

- Revenue received through the monthly service charge to the total class distribution revenue
- Revenue received through the volumetric rate to the total class distribution revenue (the fixed/variable split) as determined by applying the distribution base rates to the 2004 test year statistics

11.1.2 For each class, sub-class, or group, the ratios of the above revenues should be maintained in the 2006 distribution rates process.

11.1.3 Where the Board has not specified new adders, the distributor must adopt the same splits as for the class (sub-class, or group) revenue requirements.

11.1.4 If an applicant proposes to make any change to the effective fixed/variable split described above, they must complete and file Schedule 10-1, which includes a detailed explanation and justification for the variance from the proposed methodology.

CME's Position – Un-metered Scattered Loads

11.2 CME supports the proposal that:

11.2.1 On an interim basis for 2006, prior to the cost allocation study and rate re-design that will take place in 2007, un-metered scattered load customers should be treated as follows:

11.2.1.1 A distributor that currently has un-metered scattered load charges in <u>either</u> of the following two manners will maintain the *status quo* in its 2006 rate treatment of un-metered scattered loads:

- The monthly service charge to un-metered scattered load customers having multiple un-metered connection points is on a per customer, and not a per connection point, basis, and the level of the charge is equal to, or less than, the General Service <50 kW monthly service charge per customer.

<u>OR</u>

- The distributor has developed and implemented a unique level of monthly service charge(s) payable by un-metered scattered load customers.

11.2.1.2 A distributor that currently bills its un-metered scattered load customers as small commercial or General Service <50 kW by applying the monthly service charge on a per connection point basis, shall set the level of the monthly service charge at 50% of the monthly service charge of the General Service <50 kW rate and continue to apply it on a per connection point basis.

11.2.1.3 From a revenue perspective, a distributor shall be kept whole as a result of any rate changes to the monthly service charge for un-metered scattered loads. Any revenue shortfall that may result from this interim measure will be recovered by means of a re-allocation of the revenue shortfall over all classes (or sub-classes or groups), in proportion to the class's (or sub-class's or group's) distribution revenue, and recovered from all the distributor's customers through both the fixed and the variable components of their respective distribution rates. The re-allocation of the revenue shortfall as a result of applying this interim measure are incorporated into the worksheet Rates 1 of the 2006 EDR Model in Appendix D.

11.2.1.4 The methodology used by a distributor to estimate the load profiles and energy consumptions of these types of loads is not specifically incorporated into this interim solution. In the event, however, that a reasonable estimate of the energy use for a/several delivery point(s) is required, the specific customer will have reasonable advanced notice of the proposed method, and of the estimate of the cost to the customer to establish and monitor a reasonable estimate of the energy use for a delivery point or for several delivery points.

11.2.1.5 The applicant must complete and file Schedule 10-2 as part of its application.

CME's Position – Time of Use Distribution Rates

11.3 CME supports the proposal that:

11.3.1 A distributor that currently has a legacy time of use rate classification may either retain that classification, or attempt to harmonize it with the equivalent non-time of use classification, at its discretion. Such harmonization would be subject to any constraints resulting from bill impact mitigation.

11.3.2 If an applicant proposes to modify its legacy time of use rates, it must complete and file Schedule 10-3.

CME's Position – Time of Use Distribution Rates

11.4 CME supports the proposal that:

11.4.1 A distributor that currently has a legacy time of use rate classification may either retain that classification, or attempt to harmonize it with the equivalent non-time of use classification, at its discretion. Such harmonization would be subject to any constraints resulting from bill impact mitigation.

11.4.2 If an applicant currently has a sub-classification entitled time of use, it must complete and file Schedule 10-3.

CME's Position – Transformer Ownership Allowance

11.5 CME supports the proposal that:

11.5.1 The current levels of allowance for transformer ownership will be continued for the 2006 rates, and will be explicitly shown on the distributor's rate schedule.

11.5.2 If an applicant proposes to modify its legacy time of use rates, it must complete and file Schedule 10-3.

CME's Position – Update of Loss Adjustment Factor Reflecting Distribution System Losses Including Unaccounted-for-Energy

11.6 CME supports the proposal that:

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

11.6.2 Applicants 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).

11.6.3 If an applicant determines that specific information warrants a departure from that average (e.g. gain or loss of large customers), it must file Schedule 10-4 to identify the change from the proposed methodology, with a detailed explanation and justification for the variance.

11.6.4 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.

CME's Position – Distributed Generation

11.7 CME supports the proposal that:

11.7.1 Distributed generation (DG) is defined as, a merchant generator located within a distributor and connected directly to the distribution system to provide electricity to the distributor. This does not include a transmission-connected DG.

11.7.2 The following methodology will be made available to, and will be used by, all distributors as an interim measure for the 2006 rates process. The issue will be examined more completely as part of the 2007 rate process.

11.7.2.1 The distributor will continue to pay its transmission charges on a net basis in accordance with the Board's wholesale transmission rate schedule.

11.7.2.2 The distributor will continue to charge the current retail transmission service charges to its customers as if all the electricity requirements were being served from the transmission system.

11.7.2.3 With respect to generation developed after the current rates were set, since the rates have not been reduced to take into account that new generation, the distributor is effectively billing the load customers on a gross basis, with the differences being accumulated in the respective RSVA accounts.

11.7.2.4 The distributor will provide a transmission credit to the DG reflecting the lower transmission charges being billed to the distributor achieved by locating the generation within the distributor.

11.7.2.5 The transmission charge reductions will be shown as a credit to the DG. The credit will be funded by the transmission charge reductions accumulated in the RSVA accounts.

11.7.2.6 The level of the credit will be determined as a result of the DG's contribution that results in the actual reduction in the distributor's delivery point billing demands used for the calculation of the distributor's transmission charges, with 50% of the amount being credited to the DG. A credit would not be payable to the DG if the DG output does not reduce network, line connection, or transformation charges paid by the distributor.

11.7.2.7 The credit will be available to any DG that fulfils the Distribution System Code requirements for a generator to connect to the distributor's distribution system, subject to the physical and practical limitations within a distributor's distribution system.

11.7.2.8 End-use load customers that have load displacement generation will have the option of being billed retail transmission charges as if the generation was not on-site, and in return receive the credits outlined above for the distributed generation.

11.7.2.9 The distributor may apply for a monthly administration charge to recover the incremental cost of monitoring, billing, and administration related to the DG credit. Such a charge will require a separate cost-justified submission as part of the distributor's Specific Service Charges (see Chapter 11).

11.7.3 Each distributor must file Schedule 10-6 to identify its acceptance of the proposed methodology. If a distributor proposes an alternative to this methodology, it must complete and file the last part of Schedule 10-6 outlining the methodology it proposes, including a detailed explanation and justification for the variance from the proposed methodology.

CME's Position – Standby Charges

11.8 CME supports the proposal that:

11.8.1 Ongoing distribution costs from a customer with load displacement 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.

11.8.2 All applicants must file Schedule 10-6 to identify its acceptance of the proposed methodology.

11.8.3 All applicants must use the following methodology.

11.8.3.1 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.

11.8.3.2 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 billed on the metered demand.

11.8.3.3 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 should require a separate cost-justified submission as part of the distributor's Specific Service Charges.

11.8.3.4 If a distributor proposes an alternative to the preceding methodology, it 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.

CME's Position - Low Voltage Charges

11.9 CME supports the proposal that:

11.9.1 Low voltage charges include the following treatment of charges:

- From Hydro One Networks, for historical costs by embedded distributors
- For on-going costs from both Hydro One and other distributors
- By distributors providing low voltage and related services to other distributors

11.9.2 On-going low voltage charges to distributors by Hydro One and other distributors must be recovered on the same basis as transformation connection charges, and should be allocated to the customer classes on the same basis.

11.9.3 Host distributors must complete and file Schedule 10-8.

CME's Position - Demand Determinants

11.10 CME supports the proposal that:

11.10.1 Distributors must continue to establish the billing demands at the greater of 100% of the kW, or 90% of the kVa amounts.

11.10.2 A distributor that has established its level of the volumetric demand rates based upon the application of 100% of kVa demand may continue on this basis.

10.10 CME's Position - Recovery of C&DM, Smart Meter, and Regulatory Asset Revenue Requirements

11.11 CME's position with respect to:

11.11.1 C&DM is set out in Section 23.

11.11.2 Is still be determined

11.11.3 The regulatory asset amortization revenue requirement is that it should be recovered through a rate rider and allocated to the classes, sub-classes, or groups on the basis of a volumetric change.

CME's Position – Schedule 10-1: Determination of the Fixed/Variable Splits

11.12 CME supports the information requirements and format of Schedule 10-1 set out in the draft Handbook.

CME's Position – Schedule 10-2: Un-metered Scattered Loads

11.13 CME supports the information requirements and format of Schedule 10-2 set out in the draft Handbook.

CME's Position – Schedule 10-3: Time of Use Distribution Rates

11.14 CME supports the information requirements and format of Schedule 10-3 set out in the draft Handbook.

CME's Position – Schedule 10-4: Transformer Ownership Allowance

11.15 CME supports the information requirements and format of Schedule 10-4 set out in the draft Handbook.

CME's Position – Schedule 10-5: Determination of Loss Adjustment Factors

11.16 CME supports the information requirements and format of Schedule 10-5 set out in the draft Handbook.

CME's Position – Schedule 10-6: Distribution Generation

11.17 CME supports the information requirements and format of Schedule 10-6 set out in the draft Handbook.

CME's Position – Schedule 10-7: Standby Charges

11.18 CME supports the information requirements and format of Schedule 10-7 set out in the draft Handbook.

CME's Position – Schedule 10-8: Low Voltage Charges

11.19 CME supports the information requirements and format of Schedule 10-8 set out in the draft Handbook.

12.0 Chapter 11 - Specific Service Charges

CME's Position - Definition

12.1 CME supports the definition that a Specific Service Charge should be an approved fixed rate charged to a customer for a specific activity or service, or as a penalty. Activities include services that are:

12.1.1 Only available from, or under the control of, the distributor

12.1.2 Extra services that a distributor chooses to provide, such as those that are of benefit to the distributor or to other customers, and that are provided at a customer's request or as the result of a customer's action or inaction.

12.1.3 Over and above the distributor's standard level of service.

12.2 CME supports the proposal that:

12.2.1 Revenue from specific charges should be taken into account in calculating a distributor's total revenue requirement.

12.2.2 There should be no duplication in the recovery of costs between the Specific Service Charges and the regular distribution rates.

12.2.3 The application of a Specific Service Charge may be waived by a distributor provided that the waiver is fairly applied, the practice does not become discriminatory, and it does not provide special terms by way of bonus or otherwise, to the terms at which particular customers are supplied.

12.2.4 A distributor may apply for any unique Specific Service Charge or level of charge. Unique circumstances requiring unique charges or levels require adequate justification by the distributor as part of its application to the Board.

12.3 CME supports the proposal that:

12.3.1 Specific Service Charges can be categorized into five types of charges:

- Customer Administration Charges
- Non-Payment of Account Charges
- Service Call Charges
- Temporary Electricity Service Charges
- Other Services and Charges

12.3.2 For 2006, every applicant must complete and file Schedule 11-1 (*to be written*), outlining the Specific Service Charges it has submitted for approval as part of the rate application.

12.3.3 An applicant may choose one of four approaches to define the level of the charge to bill the customer:

- The standard amount, as specified in Schedule 11-1.
- The standard formula, as specified in Schedule 11-2, with adjustments. If the applicant elects to adjust the level determined by the standard formula, it must provide additional evidence of cost justification for the adjustments.
- The level determined on a basis other than the standard formula. An applicant must provide evidence to justify the use of a non-standard formula.
- A distributor may specify in its Conditions of Service that the specific service being provided will be charged on an actual cost, time and materials basis, or a pass-through of third party costs. On this basis, approval of the Board is not required, but the applicant must maintain records that demonstrate that the actual cost was charged to the customer.

12.3.4 Other activities undertaken by a distributor, such as billing for water or sewage for a municipality, or the provision of meter translation/verification services for other distributors, could be categorized as contractual arrangements,

The specifics of such arrangements, including the level of the charge, need not be approved by the Board, provided that the applicant submits a statement that identifies all such activities and the revenue received from them that is an offset to the distribution expenses, and states that there is no cross-subsidy of costs from the ratepayers. The distributor must maintain records that demonstrate that the actual cost was charged to the customer. Revenue from these activities must be included in Schedule 8-1.

CME's Position - Methodology

12.4 CME supports the proposal that:

12.4.1 An applicant must file Schedule 11-1 to provide a list of the services within each of the identified Charge Codes.

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12.4.2 Applicants can use Schedule 11-2 to calculate a standard set of specific service charges and that the elements of the calculation for each charge include the following:

- Direct labour (internal and/or external)
- Labour rate (internal and/or external)
- Burden rate
- Incidental (e.g. postage for mail)
- Vehicle time and rate (if applicable)

CME's Position – Customer Administration

12.5 CME supports the proposal that:

12.5.1 There are two standard levels of Customer Administration Charge:

12.5.1.1.1 One is based upon minor clerical effort (up to 20 minutes in time) with no field visit.

Services falling under the first category include the preparation of an arrears certificate, a statement of account/bill copy, or a duplicate invoice for a previous billing.

12.5.1.1.2 The other is based upon more clerical effort (up to 30 minutes in time) and possible a field visit.

Services falling under the second category include account set-up, meter dispute test, and service connection for an installation not covered in the distributor's standard level of service and special meter reads.

CME's Position – Non-Payment of Account

12.6 CME supports the proposal that the charges that should apply to non-payment of account include the following: late payment charge, collection of account service charge, and reconnection of electricity service charge. Any actual pass-through costs, such as bank charges or third party charges, may be added to these charges.

CME's Position – Late Payment Charge

12.7 CME supports the proposal that:

12.7.1 When the total amount of a customer's bill has not been paid within the time outlined by the distributor (which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill), a late payment charge may be applied to the outstanding balance.

12.7.2 A monthly interest rate of 1.5% (19.56% *per annum*) has been established as the level of this charge for all distributors.

12.7.3 The late payment charge rate and the policy of when it is charged must be disclosed and made available to the customer.

CME's Position – Collection of Account Charge

12.8 CME supports the proposal that:

12.8.1 The collection of account charge is intended to cover the field costs, or part of the costs, of additional collection activities that are beyond the routine of a distributor, as a result of an individual customer's non-payment of its account.

12.8.2 The Distribution System Code defines a disconnect/collect trip as, a visit to a customer's premises by an employee or agent of the distributor to demand payment of any outstanding amount, or to shut off or limit distribution of electricity to the customer failing payment.

CME's Position – Reconnection of Electricity Service Charge

12.9 CME supports the proposal that:

12.9.1 Pursuant to Section 31 of *The Electricity Act*, and within good management practice, a distributor may consider disconnection of electricity service for non-payment of account.

12.9.2 Within its disconnection policy, a distributor may establish a reconnection of electricity service charge. This charge would recover the costs of the physical process of re-establishing power to the customer.

CME's Position – Service Calls

12.10 CME supports the proposal that:

12.10.1 When special or extra services to a distributor's standard level of service are provided upon a customer's request, the costs can be recovered by billing the actual cost to the customer, or through a Specific Service Charge.

12.10.2 When the customer is billed the actual cost of the work, Board approval is not required.

12.10.3 If a distributor wishes to use a standard specific charge for its service calls, Board approval is required for the charge. Depending upon the amount of work involved (e.g. amount of field time), the appropriate Charge Code in Schedule 11-1 should be used.

CME's Position – Temporary Electricity Service Charge

12.11 CME supports the proposal that:

12.11.1 When a customer or its agent requests a temporary service installation, it should pay for the cost of erecting and removing any distributor-owned equipment. A charge may also be made for any transformation equipment supplied by the distributor specifically for this service.

12.11.2 The costs for these services can be recovered by billing the actual cost to the customer, or through a Specific Service Charge.

12.11.3 When the customer is billed the actual cost of the work, Board approval is not required.

12.11.4 If a distributor wishes to establish a specific charge for the provision of a temporary service, Board approval is required for the charge, which is normally inclusive of some material.

12.11.5 Since at least a component, if not all, of this service could be provided by others, the level of the charge should not be set so as to preclude the ability of another party to provide the service.

CME's Position – Other Services and Charges

12.12 CME supports the proposal that:

12.12.1 There may be special and/or extra services that a distributor chooses to provide for which it recovers the costs directly from those customers requiring the service, either through an approved service charge, or at actual cost.

12.12.2 Board approval of a rate or charge is required unless the rate of charge is one of the following:

12.12.2.1 A rate or charge for specific customer based upon the actual costs of the provision of one time service.

12.12.2.2 A general customer rate or charge that is a flow-through of third party costs.

12.12.3 The other services and charges category also includes services that may be available from providers other than the distributor.

CME's Position – Schedule 11-1: Specific Service Charges: Standard Amounts

12.13 CME supports the information requirements and format of Schedule 11-1 set out in the draft Handbook.

CME's Position – Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

12.14 CME supports the information requirements and format of Schedule 11-2 set out in the draft Handbook.

CME's Position – Schedule 11-3: Specific Service Charges: Revenue

12.15 CME supports the information requirements and format of Schedule 11-3 set out in the draft Handbook.

13.0 Chapter 12 - Other Regulated Charges

CME's Position – Definitions

13.1 CME supports the proposal that charges related to the administration of the Standard Supply Service (SSS) (to be renamed the Regulated Price Plan (RPP)), Retail Service Charges, and Non-competitive Electricity Charges are exclusive of the distribution monthly service charges, volumetric rates, and specific service charges.

CME's Position – SSS (to be re-named RPP) Administration Charge

13.2 CME supports the proposal that the SSS (to be re-named RPP) Administration Charge should be a standard charge of $0.25 per month, per customer.

CME's Position – Retail Service Charge

13.3 CME supports the proposal that retail services refer to services provided by a distributor to retailers or customers related to he supply of competitive electricity.

CME's Position – Establishing Service Agreements

13.4 CME supports the proposal that charges to a retailer should be as follows:

- Standard charge (one-time charge) of $100 per agreement, per retailer (intended to recover the costs of entering into the service agreement required by the RSC)

- Monthly fixed charge of $20 per month, per retailer (intended to recover the cost of contract administration and monitoring prudential requirements)

- Monthly variable charge of $0.50 per month, per customer (intended to recover costs related to general accounting, administration services, and other communication and customer care services necessary to maintain the contract)

CME's Position – Distributor-Consolidated Billing

13.5 CME supports the proposal that:

13.5.1 A standard distributor-consolidated billing charge of $0.30 per month, per customer, should be collected from the retailer (intended to recover the incremental costs incurred by a distributor in providing a distributor-consolidated, bill-ready service).

13.5.2 The charge for rate-ready billing should be determined based upon the incremental cost to the distributor to provide the service. A distributor must apply to the Board to establish the charge. If the Board has approved such a charge for a distributor, it is to be maintained at its current amount for 2006.

CME's Position – Retailer-Consolidated Billing

13.6 CME supports the proposal that when a retailer chooses retailer-consolidated billing, a distributor will pay an avoided cost credit of $0.30 per month, per customer.

CME's Position – Service Transaction Requests (STR)

13.7 CME supports the proposal that:

13.7.1 An STR is specific to an individual customer. Each fee will be charged on a per customer basis. These fees are to recover the incremental cost of labour, internal information system maintenance costs, and delivery costs and include the following:

- Request fee of $0.25 per request (intended to recover costs incurred by a distributor for the initial screening process of a STR) regardless of whether or not the STR can be processed. A request fee is applied to the requesting party

- Processing fee of $0.50 per request (intended to recover the costs incurred to process the transaction based upon rules and procedures set out under Chapter 10 of the RSC) applied to the requesting party if the request is processed. A processing fee is applicable to the following services:
  - A change in electricity supply for a customer from SSS to a retailer
  - A change in electricity supply for a customer from one retailer to another
  - A change in electricity supply for a customer from a retailer to SSS
  - A change in a customer's metering or billing options for customers currently served by a retailer
  - A change in customer location

CME's Position – Fee for specific STR

13.8 CME supports the proposal that:

13.8.1 A retailer or customer may request customer information as outlined in Section 10.6.3 and in Chapter 11 of the RSC. A request to deliver data directly to retailers and customers, if not delivered electronically through the Electronic

Business Transaction (EBT) system, will be honoured twice a year at no direct charge to retailer or customer.

13.8.2 Where requests exceed two per year, an information delivery charge of $2 per request, plus any incremental delivery costs, may be charged where a request is considered to be data delivered to a single address.

CME's Position – Default

13.9 CME supports the proposal that:

13.9.1 In the event of settlement payment default by a retailer, if the account remains unpaid after 10 business days from the date the settlement payment was due, and the parties have not agreed upon a remedy, the distributor may notify the retailer's customers that they will become SSS customers.

13.9.2 For the purposes of the 2006 Handbook, a distributor may treat this transfer as an STR requested by the retailer, and may recover the request and processing fee from the retailer.

Other associated costs

13.10 CME supports the proposal that:

13.10.1 If a distributor provides an associated service (e.g. special meter reading) to facilitate the process of an STR, it may recover the applicable associated costs at the level specified in its rate schedule.

13.10.2 If the Board has approved such a charge for a distributor, it is to be maintained for 2006. If no rate is in place, the distributor may apply to the Board for a specific rate.

CME's Position – Monitoring and Cost Tracking

13.11 CME supports the proposal that distributors should establish or maintain the appropriate Retail Services Costs Variance Accounts (RCVA) to record the difference between charges rendered to customers and retailers, and the direct incremental costs for the provision of these services.

CME's Position – Non-Competitive Electricity Charges

13.12 CME supports the proposal that current Board-approved rates and charges are to be maintained for 2006 for non-competitive services.

CME's Position – Wholesale Market Service Rate

13.13 CME supports the proposal that:

13.13.1 The rate of $0.0052/kWh applies to those customers of a distributor who are not wholesale market participants.

13.13.2 An embedded distributor who is not a wholesale market participant shall be treated as a customer to the host distributor and will be charged the same rate.

13.13.3 The Wholesale Market Service Rate shall be applied to the customer's metered consumption, adjusted by the distributor's total loss factor.

CME's Position – Retail Transmission Service Rates

13.14 CME supports the proposal that:

13.14.1 There are two separate rates: the retail transmission network service rate, and the retail transmission connection service rate.

13.14.2 The existing rates should be maintained for 2006, and apply to customers in each existing distribution customer class.

CME's Position – Charges/Taxes Levied by the Government of Ontario

13.15 CME supports the proposal that:

13.15.1 While Government of Ontario charges/taxes are part of a customer's bill, the Board does not approve the levels of these charges and they are not be part of the distributor's rate schedule or rate order.

13.15.2 The Rural and Remote Rate Protection (RRRP) charge for 2006 should be of $0.001/kWh.

13.15.3 A Debt Retirement Charge of $0.007/kWh (or less, depending upon the percentage of a distributor's load supplied by the former Ontario Hydro) should apply for 2006.

14.0 Chapter 13 - Mitigation

CME's Position – Impact Analyses

14.1 CME supports the proposal that:

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

14.1.2 Calculation of these bill impacts will be an integral component of the 2006 EDR Model.

14.1.3 An applicant must enter its 2005 rates into the 2006 EDR Model.

14.1.4 In conducting an impact analysis for each class of customers, both of the following comparisons will be provided by the 2006 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.

CME's Position – Mitigation Methodologies

14.2 CME supports the proposal that:

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

14.2.2 An applicant must file the following information if its rates/rates for certain classes exceed X%

14.2.3 A distributor will undertake the following mitigation measures: (To be completed after the Board's decision.)

CME's Position – Rate Harmonization (Amalgamated or Acquired Service Areas

14.3 CME supports the proposal that rate harmonization applications generally should await the cost allocation study to be completed for the 2007 rate year.

15.0 Chapter 14 - Comparators and Cohorts

CME's Position – Methodology

15.1 CME supports the proposal that

15.1.1 In order to facilitate review and assessment of the 2006 rate applications, Board staff use comparators and cohorts to screen the applications.

15.1.2 The methodology to determine the cohorts should be as follows:

CME's Position – Filing Requirements

15.2 CME supports the proposal that

15.2.1 The comparators and cohorts be determined on the basis of data filed by distributors.

15.2.2 Applicants must file, n later than Month, day, 2005 the following information on Schedule 14-1.

15.2.3 The analysis performed on this information be posted on the Board's Web site with each stakeholder being advised when this is done.

16.0 Chapter 15 - Service Quality Regulation

CME's Position

16.1 CME supports the proposal that:

16.1.1 Utilities must file their service quality indicators as part of their rate application in 2006 in Schedule 15-1.

16.1.2 A distributor's service quality indicators, their associated monitoring and reporting requirements, (where applicable) are those set out in the chart below.

16.1.3 A distributor should establish its operating performance at levels better than the minimum standards, taking into consideration the needs and expectations of their customers.

Service Quality Indicators	
Customer Service	**Service Reliability**
Connection of new services Underground cable locates Appointments Telephone accessibility Written response to enquiries Emergency response	System average interruption duration index System average interruption frequency index Customer average interruption duration index

CME's Position - Customer Service Performance Indicators

16.2 CME supports the proposal that;

16.2.1 A customer service indicator measures direct contact with the customer.

16.2.2 Distributors are expected to achieve the minimum standards for a specified percentage of the time.

CME's Position - Connection of New Services

16.3 CME supports the proposal that:

16.3.1 The connection of new services indicator measures the percentage of requests that are met within the required minimum performance standard

.

16.3.2 As a minimum performance standard for the connection of new universal services, new low voltage (<750 volts) services must be connected within 5 working days from the day on which all conditions of service are satisfied, including electrical safety inspection, at least 90% of the time.

16.3.3 New high voltage (>750 volts) service must be connected within 10 working days from the day on which all conditions of service are satisfied, including electrical safety inspection, at least 90% of the time.

16.3.4 The conditions of service that may need to be satisfied include the following:

- Payment of connection fees

- Signing of service contracts,
- Completion of distribution system extensions
- Provision of adequate lead times for delivery of equipment
- Receipt of an electrical safety inspection certificate

16.3.5 The utility must monitor its performance monthly and report the information annually to the Board. The monthly information is to be reported as follows:
- Number of new low voltage services connected
- Number of new low voltage service connected within 5 working days
- Percentage of requests for new low voltage service met within 5 working days [((2*100)/(1)]

- Number of new high voltage service connected
- Number of new high voltage service connected within 10 working days
- Percentage of requests for new high voltage service met within 10 working days [((5*100)/(4)]

CME's Position - Underground Cable Locates

16.4 CME supports the proposal that:

16.4.1 The underground cable locates indicator measures the percentage of requests for cable locates that are completed within the minimum performance standard.

16.4.2 As a minimum standard, underground cable locates must be completed within 5 working days of a customer's request, at least 90% of the time. For customers requesting a specific date, the locate must be completed within 5 working days of the requested date.

16.4.3 The cable locates included in this standard do not include emergency locates.

16.4.4 The utility must monitor its performance monthly and report the information annually.

16.4.5 The monthly information to be reported is as follows:
- Number of cable locates requested
- Number of cable locates performed within 5 working days
- Percentage of requests met within 5 working days [((2*100)/(1)]

CME's Position - Telephone Accessibility

16.5 CME supports the proposal that:

16.5.1 The telephone accessibility indicator measures the percentage of incoming calls to the general enquiry telephone number answered within the minimum of the performance standard.

16.5.2 As a minimum standard, an operator must answer in person incoming calls to the general enquiry telephone number within 30 seconds, at least 65% of the time.

16.5.3 The provision of a voice mailbox or answering machine does not constitute compliance with this measure.

16.5.4 The utility must monitor its performance monthly and report the information annually.

16.5.5 The monthly information is to be reported as follows:
- ¶ Number of general enquiry telephone calls answered
- Number of general enquiry telephone calls answered within 30 seconds
- Percentage of general enquiry telephone calls answered within 30 seconds [((2*100)/(1)]

CME's Position - Appointments Met

16.6 CME supports the proposal that:

16.6.1 The appointments indicator measures the percentage of appointments at a customer's premises or work site that are met at the appointed time within the minimum performance standard.

16.6.2 As a minimum standard, when it is necessary to meet a customer at the customer's premises or work site to conduct utility business, customers must be offered a choice of morning or afternoon appointments.

16.6.3 The appointments must be met at the appointed time, at least 90% of the time.

16.6.4 Outside of the minimum standard established for this index, if the appointed time cannot be met, the utility must notify the customer.

16.6.5 The utility must monitor its performance monthly and report the information annually.

16.6.6 The monthly information is to be reported as follows:
- Number of appointments at a customer's premises or work site made
- Number of appointments at a customer's premises or work site kept at the appointed time
- Percentage of appointments at a customer's premises or work site made within minimum standard [((2*100)/(1)]

CME's Position - Written Responses to Enquiries

16.7 CME supports the proposal that:

16.7.1 The written response to enquiries indicator measures the percentage of responses to enquiries that require written responses that are made within the minimum performance standard.

16.7.2 The minimum standard for responding to requests by a customer or an agent of the customer for written information relating to the customer's account, will be within 10 working days following receipt of the request.

16.7.3 The written response time must be met at least 80% of the time.

16.7.4 The utility must monitor its performance monthly and report the information annually.

16.7.5 The monthly information is to be reported as follows:
- Number of requests for written responses
- Number of requests for written responses provided within 10 working days
- Percentage of requests for written responses met within minimum standard [((2)*100/(1)]

CME's Position - Emergency Response

16.8 CME supports the proposal that:

16.8.1 The emergency response indicator measures the percentage of emergency responses that are made within the minimum performance standard.

16.8.2 .At a minimum, emergency trouble calls (e.g. fire, ambulance, police) will be responded to within 120 minutes in rural areas, and within 60 minutes in urban areas.

16.8.3 The definition of rural and urban should follow the municipality's definition. The arrival of a qualified service person on site will constitute the response.

16.8.4 The minimum standards must each be met at least 80% of the time.

16.8.5 The utility must monitor its performance monthly and report the information annually.

16.8.6 The monthly information is to be reported as follows:
- Number of emergency calls for rural customers
- Number of emergency calls for rural customers at which qualified staff were on site within 120 minutes
- Percentage of emergency calls for rural customers met within 120 minutes [((2*100)/(1)]
- Number of emergency calls for urban customers
- Number of emergency calls for urban customers at which qualified staff were on site within 60 minutes
- Percentage of emergency calls for urban customers met within 60 minutes [((5*100)/(4)]

CME's Position - Service Reliability Indices

16.9 CME supports the proposal that:

16.9.1 Service reliability indices measure system outage statistics. The monitoring and reporting of service reliability indices are intended to encourage utilities to maintain or exceed their existing service reliability performance.

System Average Interruption Index (SAIDI)

16.9.2 The SAIDI is an indicator of system reliability that expresses the length of outage customers experience in the year on average. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Number of Customers Served}}$$

16.9.3 All utilities are required to monitor this index monthly and to report to the Board on an annual basis. Utilities that have not monitored this index in the past nust start monitoring and reporting on this index when they start their first PBR plan.

16.9.4 Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance.

16.9.5 The monthly information is to be reported as follows:

- Total customer-hours of interruptions
- Total number of customers served
- SAIDI [(1)/(2)]

System Frequency Interruption Index (SAIFI)

16.9.6 The SAIFI is an indicator of the average number of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as, the number of interruptions normalized per customer served, and it is expressed as follows:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Number of Customers Served}}$$

16.9.6 Utilities are required to monitor this index monthly and to report to the Board on an annual basis. Utilities that have not monitored this index in the past are required to start monitoring and reporting on this index.

16.9.7 Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance.

16.9.8 The monthly information is to be reported as follows:

(1) Total number of customer interruptions
(2) Total number of customers served
(3) SAIFI [(1)/(2)]

Customer Average Interruption Index (CAIDI)

16.9.9 AIDI is an indication of the speed at which power is restored.

16.9.10 All planned and unplanned interruptions of one minute or more should be used to calculate this index.

16.9.11 CAIDI is defined as, the average duration of interruptions in the year, and it is expressed as follows:

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customer Interruptions}}$$

16.9.12 All utilities are required to monitor this index monthly and to report to the Board on an annual basis. Utilities that have not monitored this index in the past are required to start monitoring and reporting on this index.

16.9.13 Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance.

16.9.14 Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance.

16.9.15 The monthly information is to be reported as follows:
- Total customer hours of interruptions (SAIDI)
- Total number of customer interruptions (SAIFI)
- CAIDI [(1)/(2)]

CME's Position - Cause of Service Interruption

16.10 CME supports the proposal that:

16.10.1 Monitoring the cause of outages, in addition to monitoring the system reliability indices, provides valuable information as to the remedial work required.

16.10.2 Distributors should maintain a record of the causes of the outages, at a minimum, in accordance with the list presented in Table 15.2.

16.10.3 While annual reporting of this information is not mandatory, the Board should expect the utility to produce this information, should a review of the utility's service reliability be necessary.

Table 15-2 Cause of Service Interruption

Code	Cause
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage
1	**Scheduled Outage** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance
2	**Loss of Supply** Customer interruptions due to problems in the bulk electricity supply system
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
5	**Defective Equipment** Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events)

7	**Adverse Environment** Customer interruptions due to equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing (previously Code 9)
8	**Human Element** Customer interruptions due to the interface of utility staff with the system (previously Code 7)
9	**Foreign Interference** Customer interruptions beyond the control of the utility, such as animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects (previously Code 8)

CME's Position – Schedule 15-1: Service Quality and Reliability Performance 2002 to 2004

16.11 CME supports the proposal that:

16.11.1 A utility must provide its summary annual performance for the years 2002 through 2004 inclusive, on service quality and reliability indicators.

16.11.2 The information requirements and format of Schedule 15-1 set out in the draft Handbook.

17.0 Appendix A - Glossary

17.1 (Still to be completed)

18.0 Appendix B – Rate Base Accounts

18.1 (May not be required, depending on level of detail in 2006 EDR Model, in Appendix D)

19.0 Appendix C - Amortization Rates

CME's Position – Amortization Rates

19.1 CME supports the proposal that:

19.1.1 The amortization rates set out in the draft handbook should apply for 2006 rates.

19.1.2 The amortization rates apply to the respective assets listed under "Asset Type".

19.1.3 All rates are based on the straight-line method of amortization.

19.1.4 The inclusion of an asset in the chart in the draft handbook does not imply Board acceptance of the asset for inclusion in the Rate Base or for any other rate making purpose.

19.1.5 The amortization expense related to an asset used for both Distribution and non-distribution activities should be properly allocated to each type of activity.

19.1.6 Only the amortization expenses related to distribution assets may be included as an expense in rate applications.

19.1.7 The method of allocation should be reasonable and documented.

20.0 Appendix D- EDR Model

20.1 (Still to be completed)

21.0 Appendix E – Distribution Activities

CME's Position – Distribution Activities

21.1 CME supports the proposal that:

22.1.1 Activities enabling the conveyance of electricity for distribution purposes will be considered to be distribution activities. In consequence, expenses incurred in relation to the provision of these activities are defined as distribution expenses.

22.1.2 The following are generally considered to be distribution activities:

- Operation and management of the distribution system
- Meter reading services, including verification, testing, approval, and installation and removal services
- Billing and collection services
- Line-clearing services
- Repair and maintenance for the distribution lines and facilities
- Planning, design, and construction of distribution lines and facilities, including system planning and load forecasting services
- General administrative support services, including corporate services such as management, payroll, regulatory compliance service, etc..
- Telecommunications services for electricity distribution (e.g. SCADA and remote metering
- Energy efficiency services that are approved by the Board, including Conservation and Demand Management programmes
- Customer care services, including call centre services
- Energy education services
- Services required under other Board codes or guidelines
- Other services that satisfy the above definition of distribution activities

23.0 Conservation & Demand Management (C&DM)

Background

23.1 CME supports C&DM programs that are economic and impose no unnecessary and unpredictable costs on ratepayers.

23.2 CME, however, is concerned that recent OEB 2005 electric C&DM program decisions provide little or no assurance that additional C&DM funds, if approved, will be well spent.

23.3 In August 2004, CME and other customer groups wrote to the Board expressing concern that customers would not get value for C&DM spending. The Board has not replied to that letter.

23.4 Events since then have not alleviated CME's concerns. Indeed, in late 2004 several utilities sought the Board's approval to spend their 3rd tranche of Market Based Rate of Return (MBRR) on C&DM programs. Most C&DM programs submitted and approved by the

Board contained no forecasts of the energy and demand savings and no tests to ensure that the programs are economic.

23.5 CME recognizes the political atmosphere within which the OEB is considering C&DM initiatives, including the government's concerns for future electricity security of supply, and the role C&DM has been assigned by the government. Having said this, ratepayers need the Board's assurance that its decisions are not based on an irrational, and unwarranted, exuberance for C&DM similar to that experienced by the stock market in the 1990s.

Six Issues

23.6 Board Staff identified five issues on which argument was invited, as follows:

23.6.1 Revenue protection:

23.6.1.1 Should there be an LRAM and should it be prospective or retrospective?

23.6.2 Shareholder incentive:

23.6.2.1 Should there be a shareholder incentive?

23.6.2.2 If the answer is yes, what form should the incentive take, including the level?

23.6.3 Level of C&DM spending:

23.6.3.1 Should distributors bring C&DM proposals, including budgets, to the Board for approval.

23.6.3.2 Should there be a preset cap or spending requirement or should the Board set a reasonable spending level, either as a cap or as a spending requirement.

23.6.4 Should C&DM expenses be capitalized or expensed?

23.6.5 Should loss factor be treated as a regular distribution activity (the status quo) or should a performance bar be set within the rubric of C&DM? (Transcript February 4, 2005, paragraphs 1034 to 1039)

23.7 The Board added a sixth issue, namely the impact of Bill 100 on the objects of the Board and the OPA. (Transcript February 4, 2005, paragraph 855)

Revenue Protection

23.8 CME is of the view that LDCs should receive no revenue protection for undertaking C&DM programs.

23.9 At a time when the government seeks to replace a portion of the 7,500 MW of coal fired electricity generation with renewable generation and conservation at a cost per MW for renewable generation that averages $1.7 million, far higher than clean coal fired generation, it would be imprudent to ask ratepayers to pay LDCs for lost revenue arising from C&DM activities.

23.10 Indeed, if the Board approves an LRAM and an C&DM incentive for LDCs, ratepayers would pay three times for C&DM initiatives, that is for:

23.10.1 The cost of C&DM initiatives;

23.10.2 Any lost distribution revenue

23.10.3 A C&DM incentive.

23.11 If the Board approves an LRAM and an incentive, CME submits that the Board needs to explain very clearly why it believes such additional costs are in the public interest and could not be achieved in a more cost effective manner.

23.12 Moreover, the Board should be guided by London Economic's comments that "The Ontario wholesale generation market is evolving rapidly … (that) near term benefits of C&DM initiatives are largely due to avoided generation costs. … (that) uncertainties make it difficult to assess the potential benefits from C&DM, (and that) it also makes it more difficult to appropriately perform a TRC, or to calculate an SSM which requires a TRC." (Exhibit C1, page 39)

Retrospective or Prospective LRAM

23.13 In CME's view, should an LRAM be put in place, the only feasible LRAM is one based on a retrospective approach, since this ensures greater transparency of the cost to ratepayers of an ill-advised LRAM incentive (bribery) to LDCs to undertake C&DM programs.

23.14 Moreover, as a practical matter, distributors currently do not prepare load forecasts and are not required to prepare forecasts for 2006 as part of their filing requirements for other aspects of the 2006 rate filing.

23.15 Further, it is not reasonable to expect that distributors will be able to make these forecasts in time for a 2006 rate filing on July 4, 2005. As well, Mr. Chernick stated he was not sure that a prospective LRAM made sense (Transcript February 3, Paragraph 459).

23.16 CME recommends that if the Board approves an LRAM, it:

23.16.1 Allow deferral accounts to implement an LRAM mechanism on an after-the-fact basis.

23.16.2 Require such claims be supported by studies showing that the claimed load reductions were the result of the C&DM programs of the utility and were not the result of some other factor.

Shareholder Incentive

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

23.18 Most C&DM programs to 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 impose an unnecessary cost on customers.

23.19 Most distributors are at present municipally owned. Mr. Goulding, the Board's consultant, had no data to support the assertion that incentives are needed to encourage municipally owned utilities to perform C&DM programs and conceded that some ("a handful") of municipally owned utilities had successful C&DM programs without incentives. (Transcript February 1, 2005 Paragraphs 283- 326).

23.20 Mr. Goulding's assertion that incentives are needed for Ontario municipally owned utilities was based on his non-lawyer interpretation of the fiduciary responsibilities of directors under Ontario law. In short, it is opinion based on a belief with no data or hard evidence to support it.

23.21 CME submits that there is no evidence that municipally owned utilities need an SSM to encourage them to carry out C&DM programs.

23.22 With respect to whether privately owned utilities need a SSM mechanism, it was determined that for the period 1995 – 1998, when Enbridge Gas Distribution had no SSM and for some of those years there was no LRAM, Enbridge increased its DSM savings (Transcript February 3, 2005 Paragraphs 1080 – 1108)

23.23 CME submits that the evidence is that Enbridge had substantial DSM success without a SSM mechanism.

23.24 SSM mechanisms require accurate forecasts and data. Mr. Goulding's exhibit includes the following:

> 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 requires 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 need to be clearly established in advance, and the nuances well understood. (Exhibit C1 Page 29*)*

23.25 CME does not agree that with a LRAM it does not matter whether the load reduction was due to C&DM programs. However, it does agree that a daunting set of increased requirements is needed for the administration of a successful SSM mechanism.

23.26 CME notes the importance of mechanisms being established in advance and well understood. However, no utility has yet carried out a TRC test on a single C&DM program. As such, it is inconceivable that the level of understanding necessary for SSM incentives will be achieved in time for utilities to prepare submissions for July 4, 2005.

23.27 CME submits that:

23.27.1 An SSM mechanism is not necessary for 2006 rates.

23.27.2 There is no likelihood of meeting the conditions for a SSM to be effective in 2006,

23.27.3 The 2006 Handbook not provide for a SSM mechanism..

Capitalizing or Expensing C&DM programs:

23.28 CME believes that the costs of C&DM programs that have an expected life over a number of years should be capitalized for recovery over the approximate period of benefit to customers.

23.29 The costs of C&DM programs should be recorded at a class level for cost allocation so that the costs of C&DM programs can be recovered from the appropriate class or classes.

Line Losses

23.30 Distribution system line and transformer losses are the largest single use of electricity by a distributor. Managing such losses should be part of the normal business of running a distribution company.

23.31 Mr. Chernick supported the view that utility side C&DM programs are a normal part of the distribution business.

> 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, ... Normal cost recovery should be sufficient for those activities. (Transcript February 2, 2005 Paragraph 923)

23.32 Losses are currently a pass-through item. This removes the normal business incentive to make distributors more cost effective by reducing losses.

23.33 CME submits that changes should be made in loss adjustment mechanisms to restore to the distributor the 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. CME supports these proposals.

23.34 In addition CME does not believe the Board should regulate C&DM programs on the utility side of the meter.

23.35 CME recommends that distributors not be able to claim changes on the utility side of the meter as C&DM 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.

Role of Ontario Power Authority

23.36 Bill 100 established the OPA and its Conservation Bureau. Moreover, it assigns the Conservation Bureau responsibility for a leadership role in planning and coordinating electricity conservation measures and load management.

23.37 Bill 100 also makes a number of amendments to the OEB Act, reducing its objectives from seven to two:

23.37.1 To protect the interests of consumers so that consumers have access to quality electricity that is reliable, adequate and economical; and,

23.37.2 To support the generation, transmission, distribution, sale and conservation of electricity that is cost-effective so that Ontario can maintain a financially viable electricity industry.

23.38 In CME's view the primary responsibility for C&DM rests with the OPA and it would be highly inappropriate for the OEB to preempt the OPA by instituting LRAM and incentive mechanisms for LDCs in the 2006 rate setting process.

23.39 Moreover, London Economics' analysis with respect to LRAM and incentives presumes that LDCs would / should deliver C&DM programs. The Board should not accept that presumption, particularly as it carries with it the further presumption that LDCs must be induced or bribed to undertake effective C&DM programs.

23.40 The preferred alternative is to have C&DM programs delivered by the Ontario Power Authority or by another third party. In CME's view that would be more cost effective and have lower rate impact on ratepayers.

23.41 In this regard, the Board should note that Bill 100 assigns the OEB, as one of its primary objectives, to protect the interests of consumers. That objective will not be achieved with the imposition of unnecessary and unjustifiable costs arising from LRAM and incentive mechanisms.

23.42 If the OPA or other organization delivers C&DM, no LRAM or incentive would need to be paid and rates would be lower.

23.43 LDCs that deliver C&DM programs have a fundamental conflict of interest. On the one hand they seek to increase the amount of electricity they distribute and thereby their rate of return. On the other hand, C&DM programs reduce the amount of electricity they deliver. To overcome this conflict, various forms of bribery, called incentives and adjustment mechanisms (LRAM) need to be devised.

23.44 Attempts to "keep LDCs whole" and provide incentives at ratepayer expense are not justified.

23.45 Should the Board approve the delivery of C&DM programs by LDCs and approve an LRAM and an incentive, CME submits that the Board will need to explain and demonstrate very clearly why it believes such additional costs to ratepayers are in the public interest.

23.46 A complicating factor 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).

23.47 In CME's view, the reality of the OPA replaces the need for each distributor to design and implement its own C&DM programs.

Ability of LDCs to Implement C&DM programs

23.48 In his report, Mr. Goulding of London Economics International, the Board's consultant, set out the design, delivery and regulation process of cost-effective C&DM programs. (Exhibit C1, Page 13, Figure 4).

23.49 The several stages of the process for the planning and regulation of C&DM programs were discussed with Mr. Goulding in cross-examination, including whether it was reasonable to expect a small utility to undertake such a process. (Transcript February 1, 2004 Paragraphs 431 - 496).

23.50 The process involves a series of steps:

- Prepare a load forecast – Most distributors will not be preparing a load forecast for 2006.
- Identify and evaluate C&DM resources – quantitative evaluation against a Total Resource Cost test is not currently 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 February 1, 2005, Paragraph 349).
- Select the C&DM resources within broad parameters set by the Board.
- Stakeholder involvement
- Regulatory review – prior to the implementation of programs Mr. Goulding suggested that this review could 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. Problems of attribution arise 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 Gas Distribution DSM programs.

23.51 Mr. Goulding suggested that it was within the capabilities of a small utility to undertake C&DM programs (Transcript February 1, 2005 Paragraph 479) but conceded that the process would be "challenging and require some thought." (Transcript February 1, 2005, paragraph 496).

23.52 CME is less confident than Mr. Goulding in the capabilities of the management of small utilities to perform such calculations and analysis. CME 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.

23.53 While the Board's decisions related to MBRR 3rd tranche C&DM spending cannot be reversed, CME submits that its past decisions should not be a precedent for new C&DM programs.

23.54 The 2006 Handbook is an opportunity to establish the necessary discipline in C&DM spending by LDCs. It is vital that this opportunity is not missed so that a culture of spending with no restraint is not established.

In the Alternative

23.55 In CME's view it would be inappropriate for the Board to authorize LDCs to undertake C&DM programs at all but in particular in 2006, when the OPA's C&DM responsibilities are being sorted out.

23.56 In the alternative, should the Board authorize that LDCs can undertake C&DM programs in 2006, the Board should require new C&DM programs beyond those for the 3rd tranche of MBRR, should:

23.56.1 Meet the Total Resource Cost (TRC) and the Rate Impact Tests (RIM) test at a minimum

23.56.2 Not include an LRAM

23.56.3 Not set a pre-determined target level of C&DM spending.

23.56.4 Work with distributors and the OPA Conservation Bureau to set up a framework that will allow distributors to perform cost-effectiveness tests on proposed C&DM programs on a consistent and uniform basis.

23.56.5 Retain flexibility to accommodate a variety of outcomes with respect to the role of the OPA and others in designing, implementing and evaluating C&DM programs for distributors.

23.56.6 Not allow distributors to claim changes on the utility side of the meter as C&DM programs.

23.56.7 Not allow a Shared Savings Mechanism (SSM) for savings as a result of programs financed from the 3rd tranche of MBRR.

23.56.8 Require that C&MD programs that have an expected life of many years be capitalized for recovery over the approximate period of benefit to customers.

23.56.9 Require that the costs of C&MD programs be recorded at a class level for cost allocation so that the costs of C&MD programs can be recovered from the appropriate class or classes.

23.57 The OPA and the Board, in consultation, should establish the parameters for performing the TRC Test in a uniform manner across the Province.

23.58 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.

23.59 Since there are less than four months to the July 4, 2005 filing date for 2006 rates, it is unlikely that the role of the OPA' Conservation Bureau will be clearly established. Accordingly, it is unlikely that cooperative mechanisms between the OPA, the Board and distributors will be settled in time for many distributors to file C&DM 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.

23.60 CME therefore recommends the Board:

23.60.1 Work with distributors and the OPA Conservation Bureau to set up a framework that will allow distributors to perform cost-effectiveness tests on proposed C&DM programs on a consistent and uniform basis.

23.60.2 Retain flexibility to accommodate a variety of outcomes with respect to the role of the OPA and others in designing, implementing and evaluating C&DM programs for electricity customers of distributors.