Ontario Energy Board

Draft Report of the Board

on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors

and Associated Guidelines

November 30, 2006

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1 Introduction

Purpose

In its Report on the 2006 Electricity Distribution Rate Handbook[1], the Board committed to conducting a review of the issues involved in establishing the cost of capital. In 2006, the Board also committed to implementing a multi-year rate plan for distributors (the “Rate Plan”) which included an incentive mechanism to adjust rates over the period 2007 to 2009 and a commitment to develop a long-term rate setting framework by 2009. The incentive mechanism for rates over the period 2007 to 2009 is called the 2nd generation incentive regulation mechanism (2nd Generation IRM).

Board Staff have undertaken research, commissioned expert advice and consulted with stakeholders on the methods for setting the cost of capital and 2nd Generation IRM. These activities began in April 2006 and have culminated in this policy report of the Board.

This report sets out the Board’s approach to cost of capital and the 2nd Generation IRM and presents the associated guidelines for distributors to use in preparing their rate applications.

Organization of this Report

The report is organized as follows. The Board’s policy and analysis of cost of capital and 2nd Generation IRM are outlined in Section 2 and Section 3, respectively. Both sections provide brief descriptions of the matters being addressed, the Board’s policies and rationale, and summaries of the issues and options raised in consultations. Section

[1] RP-2004-0188, May 11, 2005

1 outlines in more detail how and when the adjustments to distribution rates will be implemented. Section 5 provides a summary. Guidelines associated with the policies set out in this report are contained in the Appendices.

2 Cost of Capital

The cost of capital for Ontario's electricity distributors is best understood in the context of their history. Up until 1999 the electricity distributors were mostly municipal organizations that were regulated by Ontario Hydro; from 1972 until 1998 the authority for this regulation was provided by the *Power Corporation Act*. In 1998, the passage of the *Energy Competition Act, 1998* gave the Board increased powers and a broader mandate, including responsibility for regulating the monopoly electricity transmission and distribution systems.

Since 1999, the cost of capital for distributors has been governed by the Board's Decision with Reasons in proceeding RP-1999-0034. This decision established a size-related capital structure for distributors and set the return on equity (ROE) at 9.88% based on the method used by the Board at that time to regulate natural gas utilities. This ROE method was a modified version of a method described in a report provided by Dr. William T. Cannon in 1998. That report was entitled "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities".

The subsequent phase-in of the Market Adjusted Revenue Requirement and the rate freeze imposed by Bill 210 in 2002 meant that further reviews of the cost of capital for electricity distributors were unnecessary. At about the same time, however, the Board did hold a review of ROE in response to applications from the gas distributors (RP-2002-0158). The Board found that there was no compelling reason to adopt a different cost of capital method for the natural gas distributors.

During the development of the 2006 Electricity Distribution Rate (EDR) Handbook the Board approved the continued use of the mechanistic update, consistent with the method used by Dr. Cannon in his 1998 paper, to set both allowed ROE and deemed debt rates for 2006 rate applications (the "current approach"). The updated ROE was determined by the Board for 2006 rates to be 9.00%. The stratification of debt/equity by distributor size, as a proxy for risk, was retained. The size-related deemed debt rates were updated in 2006 but the deemed capital structures were not changed.

Table 1 and Table 2 provide the allowed ROE, capital structure and deemed debt rates for distributors for the 2006 rate year, as described in the 2006 EDR Handbook.

Table 1: Allowed ROE

Average of 3- and 12-month *Consensus Forecasts* outlook for 10-year Government of Canada bond rates	4.75%
Average difference during April 2005 between 10- and 30-year Government of Canada bond yields (Source: Bank of Canada)	0.45%
Equity risk premium	3.80%
Allowed return on equity	**9.00%**

Table 2: 2006 Rates Capital Structure and Debt Rates

Rate Base	Deemed Capital Structure		Deemed Debt Rate (DR)
	Debt (D)	Equity (1-D)	
> $1.0 billion	65%	35%	5.8%
$250 million - $1.0 billion	60%	40%	5.9%
$100 million - $250 million	55%	45%	6.0%
< $100 million	50%	50%	6.25%

The Board's previous reviews of cost of capital reveal a general agreement that regulated distributors are less risky than the broader market on which the rating agencies primarily focus. Beyond that, however, there is a large potential range of risk and varied opinion on the best way of representing that risk in the current circumstances of Ontario's distribution companies. The Board is guided in this matter by the need to appropriately reflect risk in rates such that investors are provided a reasonable opportunity to earn a fair return and consumer interests are protected. The Board has looked to the advice of experts to assist in the development of an effective policy for setting the cost of capital for 2007 and beyond. In addition, the Board considered regulatory practice in several Canadian and United States jurisdictions.

2.1 Capital structure

Policy and Rationale

The Board will deem a single capital structure for all distributors for rate-making purposes. The Board has considered the concerns that have been expressed by distributors and certain members of the investment community that a reduction in equity thickness or return might result in a lower credit rating. As discussed below, the Board is not convinced these concerns warrant differentiated deemed capital structures. Therefore, **the Board has determined that a split of 60% debt, 40% equity is appropriate for all distributors.**

To date, the Board has used four size-related deemed capital structures for rate regulation of electricity distributors. As noted previously, this was based on the study conducted by Dr. Cannon for the development of the first Distribution Rate Handbook. In his study, Dr. Cannon noted that:

> Conceptually, [distributor] deemed capital structure ratios for rate-regulation purposes and/or their allowed returns on equity should vary to reflect the extent of the business risks to which each MEU is exposed. Higher relative business risks will imply less debt-carrying capacity and hence call for higher deemed common equity ratios (CERs). Furthermore, if the higher CER does not fully compensate for a MEU's relatively higher business risk, then the allowed return on equity (ROE) should also be adjusted upward to compensate MEU owners for the relatively higher total investment risk that their ownership stakes are exposed to.

However, Dr. Cannon recognized that it was not practical to review the capital structure for each distributor. He concluded that it was appropriate to stratify distributors into a limited number of groupings of similar risk. Further, he identified a number of characteristics that, in his view, affected the risk profile of a distributor:

(1) The size of the distributor's operations, assets, and revenue base;
(2) The nature and stability of the distributor's customer mix;
(3) Degree of competition from other fuels;

(4) The age and condition of the physical distribution system;
(5) Local climate peculiarities;
(6) The geographic size and isolation of the distributor's service area; and
(7) The availability of back-up self-generation capacity.

However, in his final analysis, Dr. Cannon settled on factors (1) and (6). Other criteria were rejected on the basis that the influence of each factor was generally small and/or "diversifiable". Factors (1) and (6) were assessed to be recognizably correlated with each other, and, as a result, risk categorization based on size was believed to be warranted in 1998.

The electricity distribution sector has undergone significant change over the last eight years, and that change supports the move from size-related capital structures to a common capital structure. In particular, there has been considerable restructuring through mergers and acquisitions. While there were over 300 distributors in 1998, there are now less than 90. While there are some very small distributors in existence, the trend has been toward fewer and larger distributors. A recent Government announcement of a new two-year transfer tax exemption may spur further consolidation. This trend underscores the need to ensure that the Board does not create barriers to consolidation. In the Board's view, one of those barriers is the differing capital structure of distributors.

Larger distributors generally supported the 60:40 structure as it means little or no change for them. However, smaller distributors expressed concerns.

Many distributors commented that size was an important measure of risk that must continue to be reflected in the cost of capital. Comments were made that small distributors face greater business risk than large distributors when a significant fraction of their load is from a single customer or when there is load concentration in a limited number of sectors (e.g. forestry, agriculture, etc.). According to this view, for a small distributor, a downturn in the sector may also result in consumers and local businesses (restaurants, stores, etc.) moving away, while larger distributors may operate in more diversified local economies and hence be better protected from a sector downturn.

The Board notes that load concentration risk, which was the primary focus of distributor concerns, is not necessarily related to distributor size. Horizon Utilities, Oakville Hydro and EnWin Powerlines are examples of mid-sized distributors with concentrated loads. As discussed previously, the four size-based categories have been in effect since industry restructuring and distribution rate unbundling. Based on changes to the sector over the last eight years and data from distributors' operations since 1999 the Board concludes that size is not a key determinant of, or proxy for, risk.

This conclusion is corroborated by the Board's examination of 2005 financial data filed by electricity distributors, which show that the distributors exhibit a variety of actual debt-equity structures. According to the data, many smaller distributors have leveraged themselves with debt to levels in excess of 50%. These distributors do not appear to be experiencing particular financing concerns as a result of this debt load.

A distributor, regardless of size, when planning and making decisions to manage its business risk, will organize its financing in line with its business needs.

The Board concludes that utility size no longer represents an accurate proxy for risk. As a result, there is no basis upon which ratepayers should be required to bear different costs, associated with different capital structures, on the basis of distributor size. In the Board's view, for ratemaking purposes a single capital structure for all distributors is appropriate.

To avoid the unintended consequences of transition causing gross mismatch between actual and deemed, the Board has determined that a staged implementation will be used. This is discussed in sub-section 4.1, below. In addition, if the change in capital structure, and the increase in debt, leads to higher costs for new third-party debt, those higher costs will be reflected in rates. This is explained further in section 2.2.1.

Issues and Options Raised in Consultation

Most consumer groups support the single capital structure. During the technical conference, one stakeholder acknowledged that “small cap” firms do normally attract a risk premium in the market, but stated that information asymmetry is a major reason for this. This stakeholder further commented that information asymmetry occurs when an investor knows less about a small firm than would be the case with a large firm. However, in this context, information asymmetries are immaterial for regulated firms as they all report the same data to the regulator routinely, and publicly.

Some stakeholders expressed concern that during the transition to the new deemed structure distributors will restructure and take on more debt, possibly violating existing debt covenants or risking credit rating downgrades. However, the Board notes that a distributor’s actual structure does not have to be the same as its deemed capital structure.

Larger distributors (primarily Hydro One Networks and members of the Coalition of Large Distributors (the CLD)) have not identified any concerns with the 60:40 structure. Smaller distributors commented that they would prefer the four size-based categories or, in the alternative, the two size-based categories recommended by staff’s consultants, Dr. Lazar and Dr. Prisman. During the technical conference, Dr. Lazar and Dr. Prisman confirmed that their suggested two-category structure is “transitional” to a single structure. The Board is of the view that a single end-state structure with a method of transitioning towards it from the current four structures is more appropriate.

2.1.1 Debt Component

The 60% debt component is comprised of short-term and long-term debt. To date, short-term debt has not normally been factored into the setting of electricity distribution rates. However, it has been included in rate setting for natural gas distributors. In the gas sector, an amount referred to as “unfunded short-term debt” is calculated to balance total financing with rate base.

Policy and Rationale

The Board has determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. **The short-term debt amount will be fixed at 4% of rate base**.

Based on filings of distributors pursuant to the Board’s Electricity RRR and in 2006 rate applications, it is clear that many distributors use short-term debt. The actual average for the industry is about 4%. Some distributors use it extensively as a substitute for long-term debt. This may be advantageous in a period characterized by low inflation and interest rates, but such a practice exposes the distributor – and its customers – to inordinate risk if rates climb. This risk may be reduced if the distributor prudently converts the short term debt to longer-term debt when rates start to rise.

Many distributors are using short-term debt to finance their operations. The Board believes that this should be reflected in rates. Short-term debt is generally less expensive than long-term debt and generally provides greater financing flexibility. Rates on short-term debt can be more volatile than rates on long-term debt and therefore the Board believes it is in the interests of distributors and ratepayers for the amount of short-term debt to be set at a deemed level.

Issues and Options Raised in Consultation

With respect to the short-term debt component of rate base, three other options were considered:

- No short-term debt (the status quo);
- Actual short-term debt component for each distributor; and
- Short-term debt set at 8% of the rate base.

No short-term debt

As a general principle for ratemaking purposes, the Board believes that the term of the debt should be assumed to be similar to the life of the assets that are to be acquired with that debt. This suggests that, in theory, for an industry with long-lived assets, the majority of debt should be long-term. However, in reality, some short-term debt is a suitable tool to help meet fluctuations in working capital levels. Therefore, exclusion of some consideration for short-term debt in the distributors' capital structures going forward would not be appropriate.

Actual short-term debt

While there was limited discussion of this approach, another option would be to use the actual short-term debt expressed as a percentage of the distributor's capital structure.

Although using a distributor's actual short term debt component may seem to be a more accurate approach, it may be problematic. Short-term debt is optimally used as an interim solution for managing a firm's financing requirements. It may fluctuate, although generally within a limited range. Using a firm's actual short-term debt component would be administratively challenging given the number of electricity distributors and the associated volume of data that would need to be reported and verified.

Short-term debt component set at 8%

In its July 25th discussion paper staff described an option of deeming short-term debt, needed to finance working capital, at 8% of rate base. The 8% figure was based on staff's review of Hydro One Distribution's lead-lag study filed in its 2006 EDR rate case.[2] In that study, Hydro One Networks showed that its working capital requirement was

[2] Table 1 on Hydro One's RP-2005-0020/EB-2005-0378, Exhibit D1, Tab 1, Schedule 1, Page 2 of 5.

$288.5 million (cash of $265.6 million plus materials and supplies inventory of $22.9 million) out of a distribution rate base of $3,711.7 million, or about 8% of its distribution rate base. Staff explained this derivation during the technical conference.

There was confusion as to whether this proposal would also alter the working capital allowance (WCA) from the current formula (15% of the cost of power and (defined) controllable expenses). Staff explained that this was not the case. The Board committed, during the development of the 2006 EDR Handbook, to look at the determination of the WCA before 2008, and this is documented in the Board's Business Plan.

While a higher component of short-term debt would, all other things being equal, lower the cost of capital, it may be seen as financially constraining for distributors. Based on comments to this effect made by distributors, the Board believes that a smaller short-term debt component of rate base is appropriate.

2.1.2 Equity Component

Policy and Rationale

The Board has determined that distribution rates shall reflect 40% **common equity. There will be no adjustment for a preferred share component of equity in rates, although distributors can, if they choose to do so, use preferred shares within their financing structure**.

Issues and Options Raised in Consultations

One distributor suggested that preferred shares be treated as debt, so that the deemed capital structure would be 40% common equity, up to 4% preferred shares, and the remainder as long- and short-term debt. It was argued that common and preferred shares are different.

The Board is of the view that while common and preferred shares differ, preferred shares and debt also differ. The Board is not persuaded that preferred shares should be treated as debt in the deemed capital structure for ratemaking purposes. The fact that there is no requirement for the actual debt and equity structure of a distributor to match the deemed amount in rates means that distributors can use preferred shares at their discretion.

2.2 Debt Rates

2.2.1 Long-term debt

Long-term debt is a major component of a distributor's capital structure. As noted previously, for ratemaking purposes the term of the debt should be assumed to be compatible with the life of the asset. With electricity distributors, the asset life can extend beyond 30 years. Typically, debt is incurred at the time when assets are put in service and the cost of that debt is at the prevailing market rate. This means that a distributor may be holding long-term debt at rates that differ according to when the debt was incurred. This is often called "embedded debt."

In Ontario, distributors have two main sources of debt financing: affiliates (including owners); and third parties, such as commercial banks.

Policy and Rationale

For rate-making purposes, the Board considers it appropriate that further distinctions be made between affiliated debt and third party debt, and between new and existing debt.

The Board has determined that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.

The Board has determined that the rate for new debt that is held by a third party will be the prudently negotiated contracted rate. This would include recognition of premiums and discounts.

For new affiliated debt, the Board has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate. This deemed long-term debt rate will be calculated as the Long Canada Bond Forecast plus an average spread with "A/BBB" rate corporate bond yields. The Long Canada Bond Forecast is comprised of the 10-year Government of Canada bond yield forecast (*Consensus Forecast*) plus the actual spread between 10-year and 30-year bond yields observed in Bank of Canada data. The average spread with "A/BBB" rate corporate bond yields is calculated from the observed spread between Government of Canada Bonds and "A/BBB" corporate bond yield data of the same term from Scotia Capital Inc., both available from the Bank of Canada.

On any variable-rate debt and any renegotiable-rate debt the Board will use the deemed long-term debt rate.

The deemed long-term rate will be calculated using data available three full months in advance of the effective date of the distribution rate change. The method that the Board will use to update this rate is detailed in Appendix A.

The approach to setting the rate for embedded debt at its prior approved rate is based on the fact that those rates have already been reviewed in previous cases and been determined to be appropriate.

The approach to setting the rate for new debt differs as between third party and affiliate lenders, so as to recognize that in affiliate transactions there is an opportunity for terms to be negotiated at less than “arm’s length”, which could result in less favourable terms and conditions. When a distributor is financed by a third party, however, it is expected that the distributor will obtain commercial terms and conditions, including market rates.

Issues and Options Raised in Consultations

Dr. Lazar and Dr. Prisman proposed that the deemed long-term debt rate be determined as the riskless rate plus the average spread between a sample of “A/BBB” rated corporate bonds of 5, 10 and 20 year maturities and the corresponding Government of Canada bonds. The riskless rate would be approximated by averaging estimates of the 5-, 10- and 15-year zero-coupon Government of Canada bond yields from publicly available data (e.g. from the Bank of Canada).

A concern was expressed that the 5- 10- and 15-year zero-coupon bond yields do not adequately match the life of the distribution assets. Stakeholders suggested that the bond yields should include longer terms up to 30 years. The Lazar/Prisman proposal and the method that the Board has adopted do include 30-year bond yields in the calculation of the deemed long-term debt rate.

The Board is of the view that while the Lazar/Prisman method has merit, the approach is materially more complicated and is also unfamiliar to stakeholders. In addition, the existing method produces a similar result to that which arises from the Lazar/Prisman method. Maintaining the existing method provides continuity and consistency for distributors, and the Board concludes that there is no compelling reason to change the method for setting the deemed long-term debt rate.

2.2.2 Short-term debt

"Short-term debt" normally denotes demand notes or debt that has a term of one year or less. On November 28, 2006, the Board issued a letter communicating its approved method for calculating interest rates for regulatory accounts. This provides a method to compute a short-term rate which is acceptable for short term debt.

Policy and Rationale

The Board has determined that the deemed short-term debt rate will be calculated as the average of the 3-month bankers' acceptance rate plus a fixed spread of 25 basis points. This is consistent with the Board's method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts. The Board will use the 3-month bankers' acceptance rate as published on the Bank of Canada's website, for all business days of the same month as used for determining the deemed long-term debt rate and the ROE.

For the purposes of distribution rate-setting, the deemed short-term debt rate will be updated whenever a cost of service rate application is filed. The deemed short-term debt rate will be applied to the deemed short-term debt component of a distributor's rate base. Further, consistent with updating of the ROE and deemed long-term rate, the deemed short-term debt rate will be updated using data available three full months in advance of the effective date of the rates.

Issues and Options Raised in Consultations

The topic of short-term debt rates was subject to little comment due to the Board's separate process on interest rates to be applied to deferral and variance accounts. Any issues raised have been addressed as part of the Board's consideration of that issue.

2.3 Return on Equity

2.3.1 Return on Common Equity

The return on common equity compensates investors for the opportunity cost of providing share capital to a distribution business. The cost of that capital will vary with the perceived risk of the investment. In general, the rate of return to the investor should be appropriate to the risk of the distribution company compared to that in the market.

Policy and Rationale

The Board has determined that the current approach to setting ROE will be maintained. ROE will be determined based on the Long Canada Bond Forecast rate plus an equity risk premium (ERP). The method the Board will use to update ROE is detailed in Appendix B.

The Board's current approach has been in place for six years. In this consultation process several variations on the underlying inputs and assumptions to the current method were reviewed, and one alternative method was reviewed. The review of inputs and assumptions offered a range of ROE results between 8.37% and 11.5%. The alternative method produced ROE results ranging from 5.78% to 7.02%. This alternative method would have required more time and greater costs for its implementation. Given the issues and options raised in the consultation, the Board concludes that none of the approaches reviewed is better than the Board's current method.

The Board's method will continue to include an implicit premium of 50 basis points (0.5%) for floatation and transaction costs.

The Board will also clarify the starting point for the update. The update method was established in 1999 as part of a review of cost of capital. Therefore, it is appropriate to use the ROE calculated at that time as the starting point. This figure was 9.35% and was determined by the Board in Hydro One Network Inc.'s RP-1998-0001 Decision. The Board will use 9.35% ROE as the starting point for the update.

Issues and Options Raised in Consultations

Many stakeholders identified different ways to establish what they considered to be a more appropriate ROE; however, the majority of them indicated that if their own approach was not adopted by the Board, then the status quo was preferred.

An Alternative Approach to the Risk-Free Rate and ERP under CAPM

Dr. Lazar and Dr. Prisman recommended an alternative approach that would estimate ROE as the sum of a risk-free rate and an ERP estimated using the well-known Capital Asset Pricing Model (CAPM). They proposed estimating the ERP based on a proxy sample of firms that are "similar" to electricity distributors. They proposed to set the risk-free rate using forward rates based on zero-coupon bond yield estimates.

With regard to the risk-free rate, the recommended method would take advantage of new data which the Bank of Canada began to provide in 2004. These new data are estimates of the zero-coupon yield curves that may be inferred from the traded prices of Government of Canada bonds. Zero-coupon bonds are bonds that do not pay any yearly interest to the holders; they merely promise to repay the holders the face value of the bond at some future date.

As noted, Dr. Lazar and Dr. Prisman recommended an approach that relies solely on the use of the CAPM. While it was noted that CAPM has some deficiencies, Dr. Lazar and Dr. Prisman expressed their confidence that it is the soundest of the conventional methods (notwithstanding more recent and more complex methods based on Arbitrage

Pricing Theory). They also noted that relying solely on CAPM would avoid the need for weighting of results, which is generally acknowledged as arbitrary. From their analysis, they estimated betas (a measure of the relative riskiness of the firm or sector against the market in general) of about 0.3 to 0.4.[3]

The proposed approach would result in a range of ROEs from 5.78% to 7.02% based on current data. With further analysis and some refinements to the proxy group of firms, staff calculated an ROE of 8.37% based on current data. A coalition of medium-sized distributors[4] retained Dr. Morin and Energy and Environmental Economics, Inc. who presented a study which used data from Dr. Lazar's and Dr. Prisman's report (and hence relied on CAPM), but used a different formulaic calculation of ROE. They calculated an ROE in the range of 9.8% to 10.4%.

Stakeholders criticized the Lazar/Prisman approach on the basis of a mistaken understanding that the riskless rate was estimated based on medium-term rates – the average of 5-, 10- and 15-year zero-coupon bond yields. Stakeholders suggested that this was inappropriate and that a longer term is appropriate to match the expected equity investment and asset life horizons for electricity infrastructure. In fact, the method recommended by Dr. Lazar and Dr. Prisman does incorporate data from 30 year bonds; their proposed method of averaging the 30-year zero-coupon yield curve focuses on the yields at 5, 10, and 15 years. There was also criticism of the short time series used in the analysis. While traditionally 60 year data is used, the consultants used one- to five-year data sets for the estimation of the CAPM beta and five and ten years for the market risk premium.

[3] A beta of 1 indicates equal riskiness with the market.

[4] Bluewater Power Distribution Corporation, Chatham-Kent Energy, Newmarket Hydro Ltd. and Welland Hydro-Electric Systems Corp

The sensitivity of the Lazar/Prisman approach to various assumptions and the lack of clearly comparable firms, have convinced the Board to maintain the current approach to setting ROE.

Traditional Approaches, Different ROE Estimates

Some distributors retained consultants that provided different ROE estimates using the traditional methods. Ms. Kathleen McShane of Foster Associates, Inc., the consultant for Hydro One Networks Inc., provided a cost of capital study that suggested an ROE of 10.5% is appropriate. The consultant for the Electricity Distributors Association, Mr. Robert J. Camfield of Christensen Associates Energy Consulting, tabled a study that suggested a range of ROEs of 10.2% to 11.5%. Both of these studies relied on the three standard methods of determining ROE: CAPM; the Discounted Cash Flow approach (DCF); and Comparable Earnings (CE). These studies relied on a longer time series of data. However, they also employed, to a lesser or greater extent, U.S. data in addition to Canadian data. Distributors have argued that they must compete for financing in global markets, and hence that use of U.S. data is justified on a "comparable earnings" basis. However, inclusion of U.S. data is a source of controversy, as allowed returns in the United States have typically been higher than those approved in many Canadian jurisdictions, and the market return is higher in the United States.

Some distributors argued that higher ROEs were needed because business risk for distributors has increased since 1999 – in large part due to governmental and regulatory policies which have hindered distributors' opportunities to earn a full rate of return. However, this was criticized by consumer groups on the basis that any business risk was particular to the early part of this decade, that distributors' revenue requirements have reflected a full market based rate of return since 2005, and that the multi-year rate plan should provide a predictable and stable regulatory environment under which distributors will be faced with "normal" risk.

Dr. Booth, a consultant retained by several consumer groups, supported a similar approach to that used by Dr. Lazar and Dr. Prisman, but expressed preference for the Board’s current method because it better balances stakeholder and investor interests – and that this “balance” is relied upon in many Canadian jurisdictions. Dr. Booth commented that, notwithstanding his acceptance in the interim of an ROE calculated by Dr. Cannon’s method, if he were to do the analysis directly he would end up with a result below 8%. At the technical conference, Dr. Booth observed that, in his view, it is just a matter of calculating using correct data. The fact that his result, and the results of Dr. Lazar and Dr. Prisman (as well as that of Professor Wilbur for Union Gas recently) are basically the same is merely a function of each doing what amounts to the same calculation, even if they come at it different ways.

While distributors supported the significantly higher ROE estimates of their consultants, many stakeholders – both distributors and consumer groups – recommended the retention of the Board’s current approach rather than the adoption of Dr. Lazar’s and Dr. Prisman’s method. This suggests to the Board that the current approach results in a return sufficient for distributors to continue to attract capital. Therefore, the Board has determined that the current approach to setting ROE will be maintained.

2.3.2 Premium for Infrastructure Investment

The Board notes that staff’s proposal to add a premium to the ROE for electricity distributors to provide an incentive for new infrastructure investment was not supported. While consumer groups generally rejected the need for an investment premium, distributors rejected the ROE premium on only new investment, but supported an overall increase in ROE to support new capital investment.

Some distributors did confirm that they are forecasting increased infrastructure investment for distribution system upgrades and expansion. The Board will be developing the criteria it should use to determine the Rate Plan groupings. The Board may consider, amongst other criteria, a measure of distributor capital investment to select distributors for rate rebasing in each of 2008, 2009, and 2010. Regardless, the Board is of the view that the extent and amount of capital upgrades required to ensure system reliability deserves further examination. This will be captured in a Board study undertaken in the 2007/08 fiscal year. Upon completion of this study, the Board may examine need for and appropriate form of any capital investment incentives. **The Board is not convinced that a premium is warranted at this time**.

Issues and Options Raised in Consultations

The issue of capital investment under incentive regulation is discussed in sub-section 3.6 below.

3 Incentive Regulation

Incentive regulation is an alternative to traditional cost of service rate setting. Incentive regulation is intended to provide distributors with the opportunity to increase returns to shareholders through the implementation of efficiency initiatives. These efficiencies are also intended to benefit ratepayers by reducing costs.

This is the second time the Board has adopted an incentive rate setting mechanism for electricity distributors. The first was established in 2000 in the first electricity distribution rate handbook. The Board intends to review this 2nd Generation IRM in the future and determine how a long-term mechanism should be set.

The objective of the 2nd Generation IRM is to provide regulatory certainty to distributors during the Rate Plan as several rate-related studies are carried out. As such, 2nd Generation IRM is a transitional mechanism, and not an end-state in itself. The Board needs to put in place a formulaic rate adjustment method that will return distributors to incentive regulation, without creating any major hardships for them or for their ratepayers. As outlined below, the Board will rebase rates for each of the distributors over a period of three years.

3.1 Term and Starting Base

As indicated in the Board's April 27, 2006 letter announcing this project, the term (up to 3 years) and starting base (2006 rates) for the 2nd Generation IRM have already been established.

Further, **distributors' rates will not be rebased prior to implementing the incentive adjustment for new rates effective May 1, 2007**. The term of 3 years is not for all distributors. Some, whose rates will be rebased in 2008, will have this mechanism in place for one year. Others whose rates are rebased in 2009 will have this mechanism in place for two years, and the remaining distributors will have their rates rebased in 2010. **This mechanism, therefore, will be effective for at most, three years**. The Board is currently consulting with stakeholders on the criteria it should use to determine the Rate Plan groupings (i.e., which distributors will be rebased in which years).

Issues and Options Raised in Consultation

Some stakeholders commented that the 2006 rates were based on 2004 actual data and therefore the 2nd Generation IRM starting base should be adjusted in 2007 for three years (2004 to 2007) and not one year (2006 to 2007). The Board does not believe that it is appropriate to escalate the rates for the 2006 EDR historical year filers to a current test year. The 2006 test year rates were set based either on a historical test year or on a forward forecast year and were determined by the Board to be just and reasonable for 2006.

3.2 Form

The Board deliberated on different forms of incentive regulation extensively in its RP-1999-0034 proceeding which dealt with performance based regulation for electricity distributors, and in its RP-1999-0017 proceeding in response to Union Gas Limited's application for a performance based rate mechanism. Both proceedings resulted in Board adoption of price cap regulation.

Policy and Rationale

The Board will retain a price cap form of adjustment mechanism for electricity distributors. The price cap continues to be a simple approach that will, along with the implementation of mandatory service quality requirements as described below, provide balanced incentives for efficiency improvements and the maintenance of adequate service quality over the course of the 2nd Generation IRM.

With regard to alternative mechanisms, the Board concludes that a revenue cap approach is not appropriate, at this time. Revenue cap plans make distributors indifferent to gains and losses from demand fluctuations; however, they transfer to customers the risk of volume fluctuations, thus contributing to distribution rate uncertainty.

Benchmarking regulation uses information on industry, sub-industry, or peer group cost performance to establish a benchmark price (i.e., rate) for each firm in that group. Benchmarking will also not be applied at this time. The Board believes that the data and modeling requirements necessary to establish a price cap approach within a benchmarking framework are disproportionate to the objective for the transitional 2nd Generation IRM.

Issues and Options Raised in Consultation

There was no general concern raised about a price cap form. However, Dr. Yatchew, the consultant for the Coalition of Large Distributors, made an observation regarding the effectiveness of incentive regulation in general for government-owned utilities. Dr. Yatchew commented that for government-owned distributors it may be appropriate to take political risk into account when calibrating price cap rules and when determining appropriate rates of return. The Board observes that predicting political risk and its implications through economic regulation is challenging, and that more will be learned on the matter as experience is gained with 2nd Generation IRM. The Board continues to believe, as was stated in its RP-1999-0034 Decision with Reasons, that under incentive regulation, a distributor is responsible for making its investments based on prevailing business conditions, and the objectives of its shareholder within the confines of the price cap, and subject to the service quality standards set by the Board.

3.3 Price Escalator

Under cap mechanisms, changes in price indices such as macroeconomic or industry-specific indicators drive allowed changes in output prices for regulated services (i.e., these indices escalate the allowed prices).

Policy and Rationale

The Board will use the Canada Gross Domestic Product Implicit Price Index (GDP-IPI) for final domestic demand as the price escalator. For each year the GDP-IPI for final domestic demand will be taken from the Statistics Canada publication for the previous year. The adjustment in rates will be the difference between that number and the GDP-IPI for final domestic demand built into the previous year's rates. There will be no explicit adjustments in 2nd Generation IRM for ROE or debt costs.

Macroeconomic (e.g., national or provincial gross domestic or consumer product indices) or industry-specific indices can be used to proxy inflation in an incentive regulation formula. Staff's consultant, Dr. Lowry, prepared a report for the Board on incentive regulation entitled "Second-Generation Incentive Regulation for Ontario Power Distributors" (PEG Report). A table from that report is reproduced on the next page. The table summarizes a survey of formulas approved in other jurisdictions and shows that the macroeconomic GDP-IPI is the prevalent inflation proxy used by North American regulators for gas and electric utilities.

X FACTORS APPROVED BY NORTH AMERICAN REGULATORS FOR GAS AND ELECTRIC UTILITIES

Industry	Company	Term	Jurisdiction	Acknowledged Productivity Trend	Inflation Measure	Stretch Factor	X-Factor	Comments
Gas distribution	Boston Gas (I)	1997-2003	Massachusetts	0.40%	GDPPI	0.50%	0.50%	
Gas distribution	Boston Gas (II)	2004-2013	Massachusetts	0.58%	GDPPI	0.30%	0.41%	
Gas distribution	Berkshire Gas	2002-2011	Massachusetts	0.40%	GDPPI	1.0%	1.0%	Adopted the productivity study used by Boston Gas I
Gas distribution	Consumers Gas	2000-2002	Ontario	0.63%	CPI	0.50%	1.10%	O&M Productivity
Gas distribution	Union Gas	2001-2003	Ontario	0.9%	GDPPI	0.5%	2.5%	
Gas distribution	San Diego Gas and Electric	1999-2002	California	0.68%	Industry specific	0.55% (Average)	1.23% (Average	
Gas distribution	Southern California Gas	1997-2002	California	0.50%	Industry specific	0.80% (Average)	) 2.30% (Average)	Special 1% factor added to X to reflect declining rate base
Gas distribution	Bay State Gas	2006-2015	Massachusetts	0.58%	GDPPI	0.4%	0.51%	Adopted Boston Gas II
Bundled power service	Pacificorp	1994-1996	California	1.4%	Industry specific	NA	1.4%	Company specific productivity
Power distribution	San Diego Gas and Electric	1999-2002	California	0.92%	Industry specific	0.55% (Average)	1.47% (Average)	
Power distribution	Southern California Edison	1997-2002	California	NA	CPI	0.58% (Average)	1.48% (Average)	0.90% productivity trend estimated by Edison and Commission staff but not formally acknowledged by CPUC
Power distribution	All Ontario distributors	2000-2003	Ontario	0.86%	Industry specific	0.25%	1.5%	Productivity trend referenced is the 10 year average growth rate X factor is based on 5 and 10 year weighted average
Power distribution	Nstar	2006-2012	Massachusetts	NA	GDPPI	NA	0.63% (average)	
Bundled power service	Central Maine Power (I)	1995-1999	Maine	NA	GDPPI	NA	0.9% (average)	
Power distribution	Central Maine Power (II)	2001-2007	Maine	NA	GDPPI	NA	2.57% (average)	
All utilities	**Sample Average**			**0.70%**			**1.21%**	
All industry specific	**Sample Average**						**1.58%**	
All macro-economic	**Sample Average**						**1.01%**	

Source: PEG Report (Table 1, page 55)

The above summary includes the inflation measures used in those jurisdictions. Although a macroeconomic measure, the GDP-IPI is published by a trusted source, is readily available and is likely more easily understood by the public than an industry-specific measure would be.

With regard to use of the Consumer Price Index (CPI) rather than GDP-IPI, the Board agrees with Dr. Lowry that GDP-IPI is preferable to the CPI because it tracks a more relevant set of goods and services used as inputs for production by businesses, including electricity distributors. CPI tracks the prices of consumer goods and services, whereas GDP-IPI is a broader measure of inflation that covers other relevant sectors of the economy such as capital equipment. Therefore, the Board will use the GDP-IPI as the inflation proxy for the 2nd Generation IRM.

The Board employed an industry-specific index (IPI) approach in its first generation incentive mechanism for electricity distributors. As discussed in the PEG Report, an industry-specific input price index tracks industry input price fluctuations better than an economy-wide measure. Therefore, it may better mitigate significant gains and losses that might result from the failure of a macroeconomic index to track industry input price inflation. Both electricity transmission and distribution are capital intensive businesses and are therefore sensitive to changes in the cost of funds. This pattern of fluctuation can differ from that of an economy-wide measure for extended periods. However, the Board is of the view that the GDP-IPI approach is less controversial and easier to implement: only one index needs to be obtained and the only calculation necessary will be the annual change in the index.

Staff considered the following GDP-IPI indices available from Statistics Canada:

- Ontario GDP-IPI;
- Ontario GDP-IPI for final domestic demand;
- Canada GDP-IPI; and
- Canada GDP-IPI for final domestic demand.

Both Ontario indices are available only by late April. Distribution rate adjustments are typically scheduled to be in place May 1st. Therefore, the Ontario GDP-IPI data are not available in time for the Board's distribution rate adjustment process.

Both Canada indices are published for the previous year and 4th quarter by February 28th. This timing is suitable. Of the two national indices, the Board concludes that the Canada GDP-IPI should not be used because it includes consideration of inflation in the prices of crude oil and natural gas, among other price-volatile exports. These are important to Canada as a whole, but such exports are not inputs to "wires-only" electricity distributors in Ontario.

The Canada GDP-IPI for final domestic demand excludes these inputs. Therefore, the Board will use this index. Further, the year-over-year change in the index will be used to calculate the price escalation. The Board is of the view that this index will result in a fair price adjustment because it better reflects the overall inflation experienced in the economy.

One stakeholder noted that, under staff's proposal, there would be no adjustments for ROE or for changes in distributors' debt costs during 2nd Generation IRM. They commented that while, in theory, GDP-IPI may track cost of capital changes, this would only occur over the long-term and may not be reflective of the electricity distribution industry, which is capital intensive. In response, one consumer group observed that the issue is not easily addressed within a "price-cap" incentive regulation mechanism:

- first, any adjustment to the IRM formula for changes in ROE would require distributor-specific calculations;
- second, it would also require obligating distributors to report any changes in debt costs so they, too, could be factored into the annual adjustment; and
- there would inevitably be some degree of double counting as the GDP-IPI formulation does include some consideration of changes in cost of capital.

However, two stakeholders commented that while the impact should not be material in the short term, this issue needs to be addressed in the longer-term. For 2nd Generation IRM, the Board is satisfied that during the term of the plan changes in GDP-IPI will implicitly recognize changes in the ROE and debt rates, and that therefore no further adjustment will be required.

Issues and Options Raised in Consultation

Some distributors commented that they would support the use of either CPI or GDP-IPI for the purposes of a price escalator in 2nd Generation IRM. However, they expressed concern over the exclusion of escalators related to crude oil and natural gas. Distributors commented that these factors affect many of their costs. In response to this concern, the Board notes that the GDP-IPI for final domestic demand does include these factors. It only excludes oil and gas for export.

One stakeholder supported use of an industry specific input price index and argued that it mitigates the significant gains and losses that result from the failure of a broad economy-wide index (e.g. GDP-IPI) to track changes in industry specific input prices better. However, another stakeholder noted that there is no “available” industry specific index even if the Board wanted to consider one. This stakeholder went on to say that, under the current Electricity RRR, distributors file statistics on performance based regulation related information annually. However, the Board believes that some of the required data may not be available to construct a credible industry specific index. Therefore, as a practical matter, the 2nd Generation IRM must rely on a macroeconomic index.

Staff originally proposed calculating the price escalator based on the change in the level of the GDP-IPI for final domestic demand on a 4th quarter over 4th quarter basis. This would factor year-end adjustments into the index. However, a number of stakeholders calculated that it would be better to base the change in the index on an annual over annual figure to reduce volatility inherent in using the quarter to quarter approach. The Board is persuaded that this is more appropriate.

3.4 X-factor

Under cap mechanisms, the allowed rates of change in the price of the regulated service are generally adjusted by offsets (often called an X-factor). The PEG Report detailed how X-factors based on indexing research typically include consideration of an *input price differential* (may be computed using Canadian input price trends), a *productivity differential* (may be the difference between a proxy for a total factor productivity (TFP) trend of Ontario's power distribution industry and the multi-factor productivity (MFP) trend of the Canadian economy), and a stretch factor.

Policy and Rationale

The Board has determined that distributors will be subject to a 1% X-factor for the duration of the 2nd Generation IRM. The X-factor precedents summarized in the PEG Report (reproduced in sub-section 3.3 above) suggest 1% as a reasonable reflection of relevant input price and acknowledged productivity trends. The Board believes that the Canada GDP-IPI for final domestic demand and 1% X-factor together should reasonably track industry unit costs, including efficiency gains, during 2nd Generation IRM. Therefore, the Board has determined that the value of the X-factor will remain fixed at 1% for the three-year term. Setting the X-factor at 1% over the term of the plan will provide price predictability and greater price stability. It also provides a sharing of the benefit of efficiency gains to ratepayers immediately.

Like the selection of the inflation measure, the selection of the X-factor is, for 2nd Generation IRM, a function of simplicity and transparency. Since 2nd Generation IRM is of a short duration, the Board will not develop an X-factor calibration that attempts to explicitly consider the productivity capabilities of each individual electricity distributor along with a stretch factor. Differentiated X-factors based on individual distributor circumstances would require an examination of distributor-specific evidence. In light of the spectrum of X-factor values put forward by distributors (as low as 0.7%) and consumer groups (as high as 1.2%) below, the Board believes that the 1% X-factor is reasonable for 2nd Generation IRM.

Issues and Options Raised in Consultation

Most distributors commented that 1% is too high and that the value should be based on individual distributor circumstances. They commented that distributors have been under rate freezes for an extended period of time and could not squeeze further efficiencies out of their businesses. Further, they commented that some distributors are experiencing a declining customer base – and suggested that a differential efficiency factor be determined based on growth rate. Some distributors proposed that the value of the X-factor should be 0.7%, stating a conservative approach was appropriate for 2nd Generation IRM – i.e., one without consideration of a stretch factor. The 0.7% was identified as reflective of acknowledged productivity trends without a stretch factor from the PEG Report. It was also argued that there is little reason to conclude that a distributor would be able to react to achieve efficiency savings under an IRM of such a transitional nature and short time period (some distributors will only be subject to it for one year). Therefore the X-factor simply becomes a somewhat subjective rollback of the inflation escalator. The Board does not agree that 1% is too high and that there is no opportunity for improvement in the industry over the next three years. While some distributors will only be subject to 2nd Generation IRM for one year, many will be subject to it for two and three years.

In contrast to distributors' comments that 1% is too high, consumer groups proposed that the value of the X-factor be increased. Skepticism was expressed that efficiency improvements will occur during 2nd Generation IRM given the variable term of the plan and the proposed X-factor of 1%. In one instance, it was argued that 1% is not adequate to bring about efficiency improvements. It was recommended that the X-factor be increased to 1.1% or 1.2% for 2nd Generation IRM. However, it was noted that this value is relatively modest in comparison to the values set by the Board in its previous plans (i.e., 1.5% for electricity distributors using IPI, and 2.5% for one of the gas distributors using GDP-IPI). It was also suggested that setting the X-factor for a longer term plan should include review of an input price differential (subject to the inflation factor used), historical productivity and a stretch factor (in lieu of an earnings sharing mechanism). In another instance, it was proposed that the X-factor value be determined relative to the distributor's current rates, similar to a benchmarking approach.

One stakeholder commented that although the proposed price cap rule does not recognize differential efficiencies across distributors and requires a common efficiency improvement of 1%, the stakeholder anticipated that future refinements would incorporate such differences. The stakeholder acknowledged that the proposed price cap rule comprises an important step in the process of improving regulation of Ontario distributors, describing it as simple and transparent, thereby easing regulatory burden for the regulator and the distributors.

While the Board has considered stakeholders' concerns, the Board is not convinced that for 2nd Generation IRM it is practical or necessary to set the value based on individual distributor circumstances. The 1% X-factor is low enough to recognize that distributors may be under some cost pressures and will be motivated to seek some operational savings over the term of the plan, and it is high enough to provide a benefit to consumers.

3.5 Z-factors

Under cap mechanisms, contingencies need to be built into the regulatory regime to provide the flexibility to recognize extraordinary events outside the control of distributor management. These are called Z-factors. Examples include changes in regulation, changes in accounting or tax rules, and natural disasters.

Policy and Rationale

The Board will limit reliance on Z-factors to well-defined and well-justified cases only – specifically, Z-factors will be limited to changes in regulation, changes in accounting or tax rules, and natural disasters. Changes in accounting or tax rules may result in positive or negative amounts. Regardless, in order for amounts to be considered for recovery in **a Z-factor**, the amounts **must satisfy the eligibility criteria set out in Table 3**, below.

Table 3: Z-Factor Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to operational requirements created by the Z-factor event. A significant portion of the expenditure should be demonstrably linked to addressing new operational requirements, as opposed to upgrading current procedures and systems to gain efficiencies under the guise of addressing the event. At least 75% of the amounts should be directly and demonstrably linked to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Inability of Management to Control	To qualify for Z-factor treatment, the amount must be attributable to some event outside of management's ability to control.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, **the Board intends to maintain the materiality thresholds established in the 2006 EDR Handbook**: for expenses, the materiality threshold would be 0.2% of total distribution expenses before taxes; and for capital cost recovery, the materiality threshold would be 0.2% of net fixed assets. In both cases, the materiality threshold must be met on an individual event basis in order to be eligible for potential recovery.

Consistent with guidelines established for the first generation incentive mechanism, the Board has determined that when a distributor applies for disposition of these amounts, it will be required to submit evidence that the amounts which were incurred meet the four criteria outlined above. Appendix C outlines the detailed requirements for Z-factors, and has been adapted from the Board's 2000 Electricity Distribution Rate Handbook.[5] These requirements were established in consultation with stakeholders on the matter of performance-based regulation for electricity distributors (RP-1999-0034).

The Board may review and adjust the amounts claimed under Z-factor treatment during the term of the incentive regulation plan. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. The Board is of the view that the operational response to normal events, including winter storms, is within the planning control of management and that distributors are already adequately compensated for the risk of these types of events. Therefore, the Board will expect that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event.

Issues and Options Raised in Consultation

Most stakeholders acknowledged the need for an IRM plan to provide for Z-factors.

Distributors were generally supportive of the proposed Z-factor requirements. However, some distributors expressed concern that the Board might attempt to exhaustively define when a factor would be available to a distributor, and commented that any list should be illustrative only.

[5] Revision 1.0, issued on November 3, 2000

Consumer groups commented that the tests for determining whether Z-factors are appropriate must be clear and set out prior to the commencement of the plan. Specifically that:

- the onus should be on the distributors to justify any Z-factor adjustments;
- the evidence provided in support of a Z-factor application must be thorough and subject to testing by the Board and intervenors prior to approval; and
- consistent with the 2006 EDR process there should be an onus on the distributors to bring forward Z-factors that may increase the revenue requirement or reduce it – the use of Z-factors must be symmetrical and should not be limited only to cost increases.

The last point was particularly a concern as staff did not recommend inclusion of an earnings sharing mechanism in the incentive regulation framework. Therefore, consumer groups were concerned that an unusual event that results in cost decreases or revenue increases must somehow be brought forward. The Board recognizes these concerns and is of the view that Z-factor adjustment for changes to accounting or tax rules should be symmetrical.

The Board has considered stakeholders' concerns and will limit the use and complexity of Z-factors because they undermine the basic principles of incentive regulation as opposed to traditional cost of service regulation. Therefore, only those events identified in this document (i.e., changes in regulation, changes in accounting or tax rules, and natural disasters) which are outside the control of management will be considered.

3.6 Capital Investment under Incentive Regulation

Some distributors expressed concern over aging infrastructure and the need for increased investment in that infrastructure to maintain the appropriate levels of service which may be beyond the level supported by existing rates. They proposed that the incentive regulation formula should allow for the pass through of incremental capital expenditures in consideration for growing capital program costs. This could be done through an additional factor in the price cap formula.

Hydro One Networks Inc.'s consultant, Mr. Todd of Elenchus Research Associates, proposed a factor that would be an incremental percentage to the price cap index, contingent on a distributor filing an asset condition assessment in support of its proposal.

The Board does not accept a need for a capital investment factor in an incentive regulation mechanism because the implementation of comprehensive incentive regulation is intended to encompass both capital and operating costs. This increases incentives for operating performance. In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and "outside" of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.

As discussed in sub-section 2.3.2, in the short-term the Board may be informed by a measure of capital investment to select the Rate Plan groupings for rebasing, and in the longer-term the Board plans to carry out a study on distribution system infrastructure investment in the 2007/08 year.

3.7 Earnings sharing

The Board's policy, as expressed in the Natural Gas Forum Report[6], does not support earnings sharing mechanisms (ESMs). One of the reasons for that policy decision is that ESMs are thought to reduce the distributor's efficiency incentives. Another is that it may increase regulatory burden and retroactive review of a distributor's activities.

While consumer groups generally accepted the Board's policy position on ESMs, they expressed concern that over-earning be addressed in the Board's incentive regulation framework. Also, they commented that ratepayers will not have access to full information regarding a distributor's financial results and will not have the same ability as distributors to seek Z-factor relief. Accordingly, they argued that the use of an earnings sharing mechanism would provide a level of ratepayer protection during the plan. Others commented that in the absence of an ESM, the Board should require distributors that have excess earnings to rebase first. The Board is not convinced that an ESM is appropriate for 2nd Generation IRM. However, the Board may be informed by a comparison of a distributor's actual regulatory returns with Board-approved levels in the process of determining Rate Plan groupings for rebasing.

3.8 Service Quality

Service quality provisions are an important consideration in incentive regulation plan design. Definitions and reporting requirements of electricity distribution service quality indicators (SQIs) and the minimum standards set for them are laid out in Section 15, entitled Service Quality Regulation, of the 2006 EDR Handbook. For convenience, the list of the SQIs that distributors are required to measure and report on is provided in Table 4, below.

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[6] *Natural Gas Regulation in Ontario: A Renewed Policy Framework*, March 30, 2005

Table 4: Service Quality Indicators in the Handbook

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

Distributors have been reporting their performance on these indicators since 2000. Reporting is currently made annually of monthly and annual results under the Board's Electricity RRR. Some audits of service quality have been conducted and distributors' performance during the period 2002 to 2004 was reviewed as part of the 2006 EDR applications.

Policy and Rationale

The Board is resuming its SQR review to refine its SQR regime for electricity distributors. The Board is committed to ensuring an effective SQR regime as an integral element of incentive regulation.

In September 2003, the Board initiated a consultative process to review existing electricity SQIs. The process considered changes to these indicators and standards, new appropriate measures, and what, if any regulatory consequences there should be for persistent below-standard performance. While a working group of Board staff, distributors and other stakeholders met until February 2004, the process was not completed.

Issues and Options Raised in Consultations

Several stakeholders expressed concern that the Board's SQR regime be fully operational on commencement of 2nd Generation IRM. It was commented that in any incentive regulation model it is essential to ensure that safety, reliability and quality of service are not degraded during the course of the plan.

Consumer groups urged the Board to make all SQR information publicly available, to more easily and transparently assess adherence to the requirements and allow for comparisons among all of the distributors. They commented that in the absence of full rate proceedings, the public reporting of SQIs is needed to ensure transparency and accountability for performance. Further, they noted that it would help to ensure that distributors do put forward the effort to meet and perhaps even exceed the standards.

One distributor commented that having mandatory and enforceable SQIs and performance requirements in and of itself will not result in improvements in distributors' performance as measured by the SQIs. The distributor argued that addressing this issue as a matter of compliance is contrary to the spirit of incentive regulation which it believes relies more on a cooperative approach that benefits all parties. The distributor suggested that due to the interim nature of 2^{nd} Generation IRM and the fact that SQIs and performance requirements are evolving in response to experience and improvements in data quality and availability, perhaps the Board should focus on this issue as part of a longer-term plan when better data and more precise basis of arriving at differential performance targets can be established.

One stakeholder commented that given that distribution service safety, quality and reliability is what customers are paying for in their distribution rates, it is essential that interested parties have the opportunity to address a distributor's service performance relative to the distributor's proposed rates. Therefore, despite the codification of SQR, it was requested that the Board explicitly recognize the need for service performance to remain within scope in a distributor's rate proceeding.

In light of stakeholders' comments, the Board will resume its SQR review to refine its SQR regime for electricity distributors in consultation with stakeholders. This review will include consideration for public reporting of SQIs.

3.9 Rebasing

The timing of expenditures (i.e., operating, maintenance, replacement capital, etc) that are made periodically is an issue of mounting interest in incentive regulation schemes. Some timing issues may be revealed at rebasing.

The Board is working on details for the 2008, 2009, and 2010 rebasing reviews, as outlined in the Rate Plan. This work includes the following assumptions:

- the rebasing review will be based on a forward test-year cost of service filing;
- benchmarking evidence will be used as an input to the review;
- the benchmarking method may differ from the current comparators and cohorts approach; and
- benchmarking may be applied to the proposed costs in any forward test year as well as to costs in recent historical years.

The proposed requirements for the rebasing reviews are under development.

4 Implementation

4.1 Transition to Recommended Cost of Capital

The cost of capital will be implemented into a distributor's rates in two stages. First, as part of the rate rebasing process that begins in 2008, distributors will have their debt rates and ROEs adjusted in accordance with the policies described in section 2. Second, as part of rate adjustments between 2008 and 2010, distributors will have their capital structure adjusted in accordance with the policies described in section 2 and by the method described below.

Policy and Rationale

The Board will include an adjustment to rates in 2008, 2009, and 2010 as outlined below **to transition distributors from their existing capital structures to the single deemed capital structure**.

The adjustment for capital structure would begin with the 2008 rate year. As summarized in Table 5, below, the adjustment will be based on the following schedule:

- For distributors starting at equity of 35%, the equity component will move in equal increments over 2 years until it reached 40%;
- For distributors starting at equity of 45%, the equity component will move in equal increments over 2 years until it reached 40%; and
- For distributors starting at equity of 50%, the equity component will move in equal increments over 3 years until it reached 40%.

Table 5: Transition to Target Capital Structure

			Deemed Equity Component		
Current Deemed Equity	**Variance from Target Equity of 40%**	**Transition Period (years)**	**2008**	**2009**	**2010**
35%	5%	2.00	37.5%	40.0%	
45%	-5%	2.00	42.5%	40.0%	
50%	-10%	3.00	46.7%	43.3%	40.0%

4.2 How rate adjustments will be made using the incentive mechanism

Figure 1, below, summarizes what is in and what is not in electricity distribution rates based on 2006 rate orders. The block on the left shows what is in distribution rates and the right-side denotes items that are not.

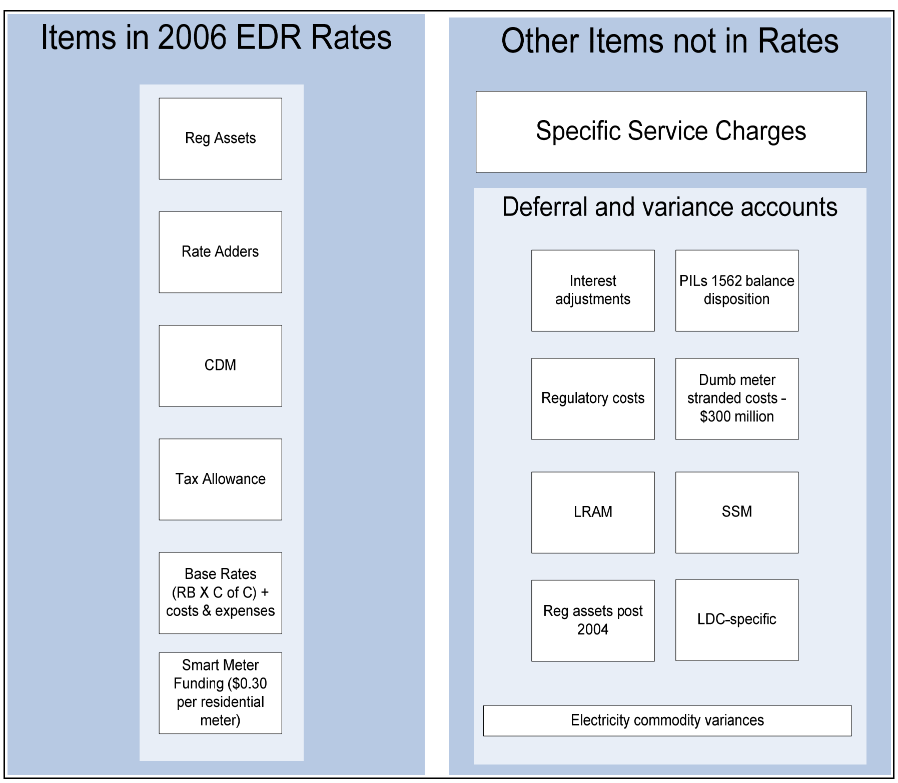

Figure 1: What's In and What's Outside of Electricity Distribution Rates

4.2.1 Allowance for Smart Meter Implementation

An amount was added in 2006 rates for smart meter implementation in order to provide "seed money" to distributors for their investment requirements and to help smooth rate shock to consumers. In its January 26, 2005 proposed implementation plan on smart meters to the Minister, the Board estimated that these costs may range from $2.00 to $4.00 per customer installation, per month.

Many parties expressed concern that further consideration be given to anticipated growth in smart meter costs to distributors. The Board has communicated separately to distributors that the process for approval of additional requirements for funds related to smart meters is under review, and may be dealt with separately from the 2nd Generation IRM rate adjustment.

4.2.2 Conservation and Demand Management (CDM)

Recently, the Board issued a letter to distributors advising them that they may apply to the Board for incremental CDM funding through distribution rates. CDM-related costs which are to be recovered through distribution rates (i.e., any new spending on CDM, revenues from recovery of a lost revenue adjustment claim, or a shared savings claim) will be dealt with separately from the 2nd Generation IRM rate adjustment. Should the Board provide for a more comprehensive revenue stabilization mechanism for distributors, then it may consider how the reduced risk might be reflected in the Board's determination of an appropriate cost of capital.

4.2.3 Treatment of Taxes

A distributor's allowance for taxes (whether PILs or actual taxes) currently includes provision for income tax, Ontario capital tax, and large corporation tax.

The Board considered whether only the income tax portion of taxes should be subject to the price cap index. The large corporation tax was repealed retroactive to January 1, 2006; however, it remains in 2006 rates. The allowance for Ontario capital tax is relatively small compared to the allowance for income tax and therefore need not be shielded from the index.

The Board has determined that the large corporation tax, which was repealed with effect from January 1, 2006, will be removed from base rates in 2007. All other taxes will be adjusted under the price cap index.

4.2.4 Deferral and Variance Accounts

Deferral and variance account balances will be dealt with in accordance with the provisions of the *Ontario Energy Board Act, 1998*.

Consistent with its proposal on Z-factors, the Board has determined that, to the extent possible, it will limit reliance on creation of new deferral accounts during the term of the scheme to well-defined and well-justified cases only. Z-factor rules should govern need for, and treatment of deferral accounts.

4.2.5 Application of the Price Cap Index

The Board will apply the price cap index uniformly across all customer classes and to both the monthly service charge and volumetric rate, including taxes. Also, the adjustment for 2007 rates will be based on the approved 2006 information. This will require a standardized and simple application to be filed by distributors.

The index will not be applied to specific service charges as the Board recently completed a generic review of these charges.

There are a number of components to distribution rates to which the index will not be applied. This includes the current smart meter amount, regulatory assets amounts, rate adders, and CDM amounts. The current smart meter amount may be affected by the on-going review that the Board is engaged in to determine how smart meter funding should be provided.

This "de-construction" of 2006 rates is conceptually illustrated in Figure 2, below.

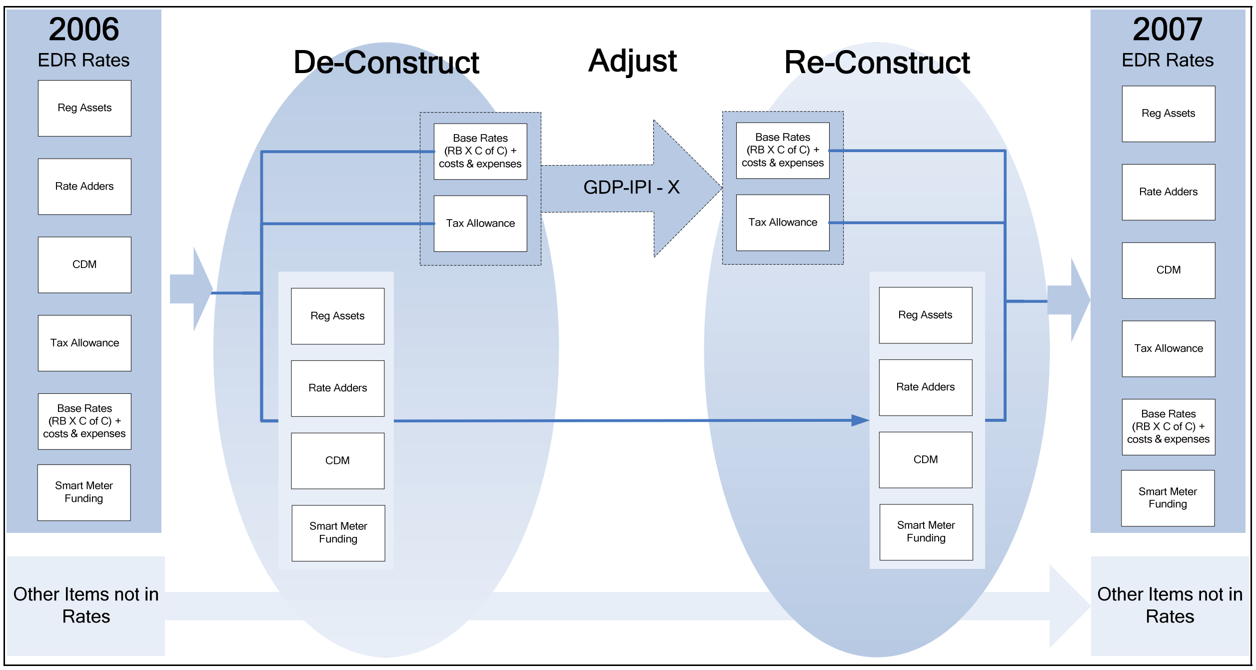

Figure 2: Conceptual Diagram of 2007 Rate Adjustments

The practical implementation of this approach using the 2006 rates as a point of departure may mean that some of this de-construction could occur at the base revenue requirement level. Regardless, the resultant monthly service charge and volumetric rate (both including taxes) for all customer classes will have been adjusted uniformly by the price cap index amount. That is, if the price cap index is 1%, then the index will be applied so that the rates, including taxes, will all be adjusted upwards by 1%.

After adjusting the base rates and taxes with the price cap index, rate elements would be “re-constructed” to derive 2007 rates.

As discussed above, the adjustment for capital structure would begin with the 2008 rate year.

4.3 Off-ramps

The Board expects distributors to use the incentive mechanism to file a rate application as required over the three-year period to effect rate adjustments in 2007, 2008, and 2009. As noted previously, there are limited adjustments available to distributors. If these adjustments are insufficient for specific cost pressures (e.g., additional capital investment) or the distributor is in the tranche to be rebased, then the Board would expect these distributors to file a comprehensive cost of service application and not to rely on the simplified filing requirements for the incentive mechanism.

5 Summary

The Board engaged many interested stakeholders in the discussion of an appropriate cost of capital and 2nd Generation IRM for electricity distributors. This consultation aided the Board in developing the policies detailed in this report. The Board has appreciated the input from all stakeholders in determining the approach it should take.

5.1 Cost of Capital

The cost of capital policy will remain in effect until it is reviewed and changed by the Board. The cost of capital elements are summarized in the following table.

Table 6: Components of the Board's Cost of Capital Policy

Capital structure	• One structure – 60% debt and 40% equity. • Move to this structure equally: 2 yr period for distributors closing a 5% gap; and a 3 yr period for those closing a 10% gap. Start in 2008, finish by 2010.
Debt structure	• One structure to include short-term debt and long-term debt: deemed short-term debt percentage of rate base based on average of distributors; and long-term debt is difference between 60% and short-term debt. Short-term debt amount is 4%. Long-term debt amount is 56%.
Equity structure	• One structure to include common equity of 40%.
Short-term debt rate	• Short-term rate is the average of the 3-month Bankers' acceptance rate over the weeks of the same month as is used for estimating long-term debt rates and the ROE, plus a spread of 25 basis points.
Long-term debt rate	• Existing debt that is either affiliate or third party will be unchanged from the Board approved values. • New third party debt – at the rate prudently negotiated by the distributor with the financing company. • New affiliate debt – lower of the contracted rate or the updated deemed debt rate. Updated deemed rate is consensus forecast plus the premium of A/BBB bonds. Premium is difference of average A/BBB Long-term Corporate Bond yield from long Canada Bond yield.
Common equity return	• No change to current ROE method – modified CAPM method which includes a consensus forecast rate plus an equity risk premium. This includes an implicit 50 basis points for transactional costs.

5.2 Price Cap Incentive Regulation

This 2nd Generation IRM policy will remain in effect until its final application in the 2009 rate year. The rate adjustments for the 2007 rate year will apply to all distributors. For the 2008 rate year the policy will apply to distributors that do not apply for rebasing. For the 2009 rate year it will apply to those remaining distributors that have not yet applied for, or been subject to, rebasing. The mechanism elements are summarized in the following table.

Table 7: Components of the Board's 2nd Generation Incentive Regulation Mechanism Policy

Price Escalator	• Canada GDP-IPI for final domestic demand – updated annually.
X factor	• Fixed at one percent per year for term of plan – all distributors subject to the same value.
Z-factors	• Will be limited to changes in regulation, changes in accounting or tax rules, and natural disasters and based on the four criteria of causation, materiality, beyond management to control and prudence.

Appendix A: Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread with "A/BBB" rated corporate bond yields to determine the updated deemed debt rate.

The following approach is consistent with the ROE method. As per the approach adopted in the 2006 EDRH, the ROE and the long-term debt rates are based on the same risk-free rate forecast. Therefore, they differ only through the risk premiums that reflect their distinct natures and for which lenders/investors seek commensurate returns. This approach simplifies the calculations and aims to make it easier to understand the numbers. Specifically, the Long Canada Bond Forecast ($LCBF_t$) used will be the same as that used for updating the ROE. The average spread between "A/BBB" rated corporate bond yields and 30-year (long) Government of Canada Bond yields will be calculated as the average spread over the weeks of the month corresponding to the Consensus Forecasts.

The deemed Long-Term Debt Rate ($LTDR_t$) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_w (CorpBonds_{w,t} - {}_{30}CB_{w,t})}{n}$$

Where:

- $CorpBonds_{w,t}$ is the average long-term corporate bond yield from Scotia Capital Inc. for week w of period t [Series V121761];
- ${}_{30}CB_{w,t}$ is the 30-year (long) Government of Canada bond yield for week w of period t [Series V121791]; and
- n is the number of weeks in the month for which data are reported.

Appendix B: Method to Update ROE

ROE Update for any Period

Using March 1999 as the starting calculation and substituting for the initial ROE and Long Canada Bond Forecast approved by the Board in the Decision RP-1998-0001 the following is the adjustment formula for calculating the ROE at time *t*:

$$ROE_t = 9.35\% \quad + 0.75 \times (LCBF_t - 5.50\%)$$

The ROE must be set in advance of the approved rates. The final ROE will be factored into rates using the Long Canada Bond Forecast based on *Consensus Forecasts* (as detailed below) and Bank of Canada data three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes, the ROE will be based on January data – effectively *Consensus Forecasts* published during that month and Bank of Canada data for all business days during the month of January. The necessary data is available within the first or second business days after the end of the month and thus poses no delay for determining rates.

Long Canada Bond Forecast for any Period

For any period *t* the Long Canada Bond Forecast $LCBF_t$ can be expressed as:

$$LCBF_t = \left[\frac{{}_{10}CBF_{3,t} + {}_{10}CBF_{12,t}}{2} \right] + \frac{\sum_i ({}_{30}CB_{i,t} - {}_{10}CB_{i,t})}{I_t}$$

Where:

- ${}_{10}CBF_{3,t}$ is the 3-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;

- ${}_{10}CBF_{12,t}$ is the 12-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time t;
- ${}_{30}CB_{i,t}$ is the actual rate for the 30-year Government of Canada bond yield at the close of day i (as published by the Bank of Canada) during the month (this is the previous month data, the same as used for updating the ROE for natural gas distribution) corresponding to time t;
- ${}_{10}CB_{i,t}$ is the actual rate for the 10-year Government of Canada bond yield at the close of day i (as published by the Bank of Canada) during the month corresponding to time t; and
- I_t is the number of business days for which published 10- and 30- Government of Canada bond yields are published during the month corresponding to time t.

Appendix C: Z-Factors

A Z-factor has been incorporated into the incentive regulation mechanism for well-defined and well-justified cases only – specifically, Z-factors will be limited to changes in regulation, changes in accounting or tax rules, and natural disasters.

A distributor may record amounts for extraordinary events (i.e., Z-factors) which meet the eligibility criteria presented below.

A distributor must follow the requirements listed below to be eligible to apply to the Board to claim any amounts into rates which the distributor has recorded for the eligible extraordinary events.

Eligibility Criteria

In order for extraordinary event amounts to be considered for recovery in the Z-factor, the amounts must satisfy all four tests set out in the following table:

Criteria	Description
Causation	Amounts should be directly related to operational requirements created by the Z-factor event. A significant portion of the expenditure should be demonstrably linked to addressing new operational requirements, as opposed to upgrading current procedures and systems to gain efficiencies under the guise of addressing the event. At least 75% of the amounts should be directly and demonstrably linked to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Inability of Management to Control	To qualify for Z-factor treatment, the amount must be attributable to some event outside of management's ability to control.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

The above four criteria will be applied to determine the eligibility of amounts for recovery through Z-factors, or any other approach deemed appropriate as a result of Board review. It should be noted that when an electricity distributor does apply for disposition of these amounts, it will be expected to submit evidence that the costs/revenues which were incurred/received meet the four standards outlined below in its annual application.

Causation

For extraordinary event related amounts, the revenue or expense must be clearly outside of the base upon which rates were derived.

Materiality

Recovery is reserved for amounts which have a significant influence on the operation of the distributor. As a guideline, an expense will be considered material if it involves 0.2% of total distribution expenses before taxes; and a capital cost will be considered material if it involves 0.2% of net fixed assets. Therefore, materiality will differ depending on the size of the distributor. Further, in both cases, the materiality threshold must be met on an individual event basis in order to be eligible for potential recovery.

Inability of Management to Control

In some circumstances, an activity is not within management's control (e.g. a requirement to conform to a change in regulation or a tax change). Options are sometimes available for management to address a problem, each with various tradeoffs between cost and effectiveness. The distributor will be required to supply the details of management's plans for addressing extraordinary events in support of the distributor's request for special cost recovery. The Board may limit the recovery of certain amounts associated with activities.

Prudence

In supporting the prudence of the expense, the distributor will need to justify the reasonableness of the amount relative to other options that the distributor may have had. For example, if the distributor must replace their billing system to deal with government policy direction on new billing requirements, the amount incurred must be justified relative to other options that the distributor may have, such as outsourcing, purchase of a new system, or revision of the existing system.

Board Review

The Board may review and adjust the amounts claimed under Z-factor treatment at any time during the term of the incentive regulation plan.

Balancing Account

Those amounts that pass the four-part test outlined above should be included in account 1572, "Extraordinary Event Costs" of the Board's Uniform System of Accounts contained in the Accounting Procedures Handbook.

Interest on these deferral accounts shall be separately recorded within these accounts. The interest shall be calculated on the monthly opening balances in these accounts at the rate set in accordance with the Board-approved method for accounting interest rates (i.e. short-term carrying cost treatment) for variance and deferral accounts.

In support of a rate adjustment related to extraordinary amounts, the distributor must indicate the amounts booked to these accounts in the previous year and provide evidence that these amounts satisfy the four criteria listed above. Distributors must also propose a disposition amount for these accounts. The distributor must also provide the basis upon which the disposition amount should be allocated to each rate class, including a discussion of the merits of alternative allocations considered. The disposition amounts allocated to each rate class from the deferral account should then be tallied, and a rate class specific revenue requirement adjustment determined.

Disposition Account

The size of the prospective rate adjustment will not be subject to a predefined limit. The absence of a predefined disposition limit will give individual distributors the flexibility to propose the rate rider with due consideration to other rate-related customer impacts.

The Board may either, adjust the class-specific rate adjustments directly based on the information provided, or may seek additional information from the distributor and/or may request a review and report from the Board’s Chief Regulatory Auditor on cost eligibility and the derivation of the rate rider.

Appendix D: Filing Requirements for 2007 Rate Adjustments

The implementation of the cost of capital and 2nd generation incentive regulation mechanism policies will occur first with rate adjustments scheduled for May 1, 2007. The 2007 rate adjustments will include:

- the 2nd Generation IRM price cap index adjustment; and
- the removal of the Large Corporation Tax Allowance (for those distributors previously subject to this tax).

The price cap index adjustment will be applied to distribution rates (fixed and variable) net of the Smart Meter Funding increment, Large Corporation Tax Allowance, and incremental 2006 CDM funding. The adjustment will not apply to the regulatory assets rate rider or to Specific Service Charges. While the smart meter funding will continue unadjusted in rates, the Large Corporation Tax and the approved incremental 2006 CDM funding will be removed from rates.

A model (the “IRM Model”) has been developed to be used by distributors in applying for rate adjustments. The IRM Model is based on the 2006 EDR Model and will be available for downloading from the Board’s website. Distributors will be required to make a number of data entries from their approved 2006 EDR Model, including the complete approved 2006 EDR tariff schedule. The steps are detailed below.

2006 EDR Tariff Sheet as Approved by the Board

All distributors must enter all approved 2006 rates. Distributors must also input the 2006 Smart Meter Funding increment that was added to their Monthly Service Charge.

Large Corporation Tax Allowance

For those distributors that had a Large Corporation Tax (LCT) allowance approved in their 2006 distribution rates, the model will reduce rates to reflect the removal of this allowance in 2007. These distributors must input their 2006 approved LCT allowance from their EDR models and 2006 base revenue requirement from the EDR model. The reduction in the allowance will be reflected through a percentage decrease in distribution rates calculated by the ratio of 2006 LCT allowance to the 2006 Base revenue requirement.

The LCT allowance will be removed from 2006 rates before the price cap adjustment is applied.

Incremental Approved 2006 CDM Funding

2006 CDM funding approved in rates for 2006 will be removed from rates before the price cap adjustment is applied. This adjustment does not apply to funds approved under the third tranche of the Market Adjusted Revenue Requirement approved in rates in 2005.

Price Cap Adjustment

Distribution rates are to be adjusted under the 2^{nd} Generation IRM plan each year for two factors: a price escalator and an X factor. In addition, beginning in 2008, the price cap formula will also include an adjustment for the transition to the common deemed capital structure for rate-setting purposes.

The Board has determined that GDP-IPI – for final domestic demand is to be used as the price escalator for the 2^{nd} Generation IRM. The Board expects applicants to use, as a proxy, the current value of 1.92% in their applications. The IRM Model will include this proxy as a reasonable estimate of the index result. When the final 2006 data are published by Statistics Canada in late February 2007, the Board will adjust the inflation index in each distributor's rate application model, to ensure this final published number is used to adjust rates for all distributors.

The X-Factor will then be applied to reduce the upward adjustment resulting from the GDP-IPI value.

The IRM Model will apply the price cap adjustment to fixed and variable distribution rates net of the 2006 smart meter funding increment, Large Corporation Tax allowance, incremental 2006 CDM funding. Further, the price cap will not apply to rate riders or Specific Service Charges.

The Smart Meter Adder

There will be no change to the Smart Meter Funding currently included in the Monthly Service Charge for Metered Customers in accordance with the Board's Decision RP-2005-0020/EB-2005-0529 and as approved in the Board's Decision and Rate Order for each distributor's distribution rate application. The current rate adder will be removed and then re-incorporated into the 2007 rate so that this funding is unaffected by the price cap adjustment. However, the funding may be affected by the on-going review that the Board is engaged in to determine how smart meter funding should be provided.

When all adjustments are complete, the IRM Model will generate a new 2007 distribution tariff sheet for the utility that will accompany the Board's decision for each distributor.

Bill Impacts

The IRM Model will include a bill impact analysis, which will provide bill impacts of the distribution rate change only. This analysis is similar to that used in assessing rate applications in recent years.

The Board acknowledges that RPP prices could also change on May 1, 2007 and therefore the IRM Model will include an additional bill impact analysis that will be used when any RPP change is released, expected to be in mid-April 2007.

Manager's Summary

Each application should include a completed IRM Model and a brief Manager's Summary explaining all rate adjustments applied for.