RP-1999-0034

IN THE MATTER OF a proceeding under sections 19(4), 57, 70, and 78 of the *Ontario Energy Board Act*, *1998* S.O. 1998, c. 15, Sched. B to determine certain matters relating to the Proposed Electric Distribution Rate Handbook for licensed electricity distributors.

BEFORE: George Dominy
Vice Chair and Presiding Member

Paul Vlahos
Member

Sally Zerker
Member

DECISION WITH REASONS

January 18, 2000

TABLE OF CONTENTS

1. **INTRODUCTION** 1
- 1.1 THE PROCEEDING 1
- 1.2 THE STRUCTURE OF THE DECISION/ISSUES 6

2. **GENERAL APPROACH TO PBR** 9

3. **INITIAL RATES** 15
- 3.1 UNBUNDLING 15
- 3.2 ADJUSTMENTS TO UTILITY REVENUE REQUIREMENT 22
  - Market-based Return 22
  - Treatment of Contributed Capital 25
  - Transition Costs 30

4. **ANNUAL RATE ADJUSTMENTS** 33
- 4.1 INPUT PRICE INDEX 33
- 4.2 THE PRODUCTIVITY FACTOR AND SHARING 37
- 4.3 THE Z FACTOR 42
- 4.4 INTER-CLASS RATE FLEXIBILITY 44

5. **SERVICE QUALITY** 47

6. **DEMAND SIDE MANAGEMENT** 55

7. **COMPLETION OF THE PROCEEDING AND COSTS** 59

INTRODUCTION

1.

1.1 THE PROCEEDING

1.1.1 In anticipation of the passage of the *Energy Competition Act, 1998* (Bill 35), in October 1998 the Ontario Energy Board ("Board" or "OEB") stated its intent to implement new approaches to regulation and to consider the use of Performance Based Regulation ("PBR") wherever it is appropriate[1].

1.1.2 In view of the large number of electricity distribution utilities in the Province of Ontario, the Board determined that it would be expedient to establish a framework for guidelines on the application of PBR to the electricity distribution industry.

1.1.3 Board staff issued a document[2] in October 1998 and held educational seminars to familiarize stakeholders with the concept of PBR. Regional workshops were also held to obtain stakeholder input on the most appropriate approach to PBR for electricity distribution. An evaluation of the input received at the workshops was presented in a report[3] issued in December 1998 and was used to identify topics for further discussion.

[1] OEB Draft Policy on Performance Based Regulation. OEB. October 2, 1998.
[2] PBR Options for Electricity Distribution in Ontario. OEB Staff Report. October 16, 1998.
[3] Performance Based Regulation Framework for Electricity Distributors in Ontario. December 17, 1998.

1.1.4 Four task forces were established to address the following topics: cap mechanisms, yardstick mechanisms, implementation, and distribution rates. The efforts of the task forces were coordinated by Board staff. Technical expertise on PBR and industry restructuring was provided to the task forces by consultants retained by Board staff. The task forces consisted of 83 volunteer stakeholder members representing various electricity distributors, gas utilities, customer groups, and special interest groups. The task forces met from mid-January 1999 through April 1999. To address the diversity and large number of emerging issues on PBR and restructuring in general, working groups were formed within each of the task forces. The reports produced by the various working groups were compiled by Board staff into task force reports[4] [5] [6] [7] and issued in mid-May, 1999. Individual task force member position papers were included as appendices to the task force reports.

1.1.5 A Board Web site provided updates on the process for the benefit of parties who were not participating in the task forces.

1.1.6 The Board staff Proposed Electric Distribution Rate Handbook ("the draft Rate Handbook") was distributed on June 30, 1999. This draft document contains a proposal for a regulatory framework for the Board to use in developing and administering electricity distribution rates in the Province. Regional seminars were held across Ontario to provide stakeholders with an understanding and clarification of the proposal.

1.1.7 The draft Rate Handbook contains proposed rate policies, guidelines and procedures to be used by the Board in the establishment and adjustment of electricity distribution rates in the Province of Ontario for a first generation PBR plan. The proposed plan has a three-year term for the period 2000-2002.

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[4] Report of the Ontario Energy Board Performance Based Regulation Cap Mechanism Task Force. May 18, 1999.

[5] Report of the Ontario Energy Board Performance Based Regulation Yardstick Task Force. May 18, 1999.

[6] Report of the Ontario Energy Board Performance Based Regulation Implementation Task Force. May 18, 1999.

[7] Report of the Ontario Energy Board Performance Based Regulation Distribution Rates Task Force. May 18, 1999.

1.1.8 The Board, on its own motion dated August 19, 1999, convened a proceeding under subsections 19(4), 57, 70, and 78 of the *Ontario Energy Board Act, 1998* S.O. 1998, c. 15, Sched. B (the "Act" or the "OEB Act") to determine certain matters relating to the draft Rate Handbook for licensed electricity distributors with respect to the distribution of electricity to end-use customers. The Board determined that a proceeding on the draft Rate Handbook was appropriate to provide the information necessary for the Board to finalize the draft Rate Handbook.

1.1.9 A technical workshop was held September 2-3, 1999 to deal with issues of data availability and analysis methodology relating to the proposal.

1.1.10 Interested parties were requested to file written submissions providing comment on the draft Rate Handbook by September 14, 1999.

1.1.11 A technical conference was held September 21-27, 1999 to provide the opportunity for clarification on the submissions filed.

1.1.12 From October 4 through October 7, 1999 parties made oral submissions before the Board and the Board sought clarification on participants' views. Participants had the option of providing the Board with final written submissions by October 22, 1999. A number of participants exercised this option.

Parties to the Proceeding

1.1.13 Below is a list of those parties who actively participated by filing submissions. Only the names of those parties who are mentioned in this Decision have been abbreviated.

<u>Combined Interventions - Electric Utilities</u>

Bracebridge Hydro, Brampton Hydro, Cambridge and North Dumfries Hydro, Guelph Hydro, Niagara Falls Hydro-Electric Commission, Oakville Hydro, Pickering Hydro, Richmond Hill Hydro-Electric Commission and Waterloo North Hydro (“The Coalition”)

Hydro Mississauga, London Hydro, Oshawa PUC, Sarnia Hydro, St. Catharines Hydro, Whitby Hydro, Petrolia PUC, St. Thomas PUC, GPU Electric Inc./GPU Services Inc. and Collingwood PUC, ENERConnect (“Mississauga et al”)

Halton Hills Hydro and Peterborough Hydro

Aurora Hydro, Georgina Hydro, Innisfil Hydro, Markham Hydro, Newmarket Hydro, North Bay Hydro, Orillia Water, Light and Power, Richmond Hill Hydro, Whitchurch-Stoufville Hydro (“Upper Canada Energy Alliance” or “Upper Canada”)

Individual Interventions - Electric Utilities

Hydro-Electric Commission of the City of Nepean (“Nepean Hydro”)

Municipality of Chatham-Kent Public Utilities Commission (“Chatham-Kent Hydro”)

Ottawa Hydro Electric Commission (“Ottawa Hydro”)

Public Utilities Commission of the City of Sault Ste. Marie (“Sault Ste. Marie Hydro”)

Toronto Hydro Electric System Limited (“Toronto Hydro”)

Other

Nova Scotia Holdings Inc., CanEnerco Energy Marketing Limited, Sunoco Inc., Flamborough Hydro Electric Commission, Lindsay Hydro-Electric System

Aiken & Associates

City of Nepean

City of Peterborough

Consumers' Association of Canada ("CAC")

Energy Probe Foundation ("Energy Probe")

Direct Energy Marketing Limited and Enershare Technology Corporation

Enbridge Consumers Gas ("Enbridge Consumers")

Energy Cost Management Inc. ("ECMI")

Federation of Ontario Cottagers' Associations Inc. ("FOCA")

Great Lakes Power Limited ("GLPL")

Green Energy Coalition ("GEC")

Independent Electricity Market Operator

The Heating, Ventilation, Air Conditioning Contractors Coalition Inc.

Metropolitan Separate School Board, and the Ontario Association of School Business Officials

Municipal Electric Association ("MEA")

Natural Resource Gas Limited

Ontario Energy Savings Corp.

Ontario Federation of Agriculture ("OFA")

Ontario Hydro Services Company ("OHSC")

Ontario Natural Gas Association

Ontario Power Generation Inc.

Pollution Probe Foundation ("Pollution Probe")

Power Workers Union ("PWU")

PSEG Global Inc. ("PSEG")

TransCanada PipeLines Limited

Vulnerable Energy Consumers Coalition ("VECC")

1.1.14 Board staff were assisted by consultants from PHB Hagler Bailly.

1.1.15 The Board also received various letters of comment.

1.2 THE STRUCTURE OF THE DECISION/ISSUES

1.2.1 This Decision deals with certain issues raised by the parties. It also deals with certain issues not explicitly addressed in the draft Rate Handbook or where clarification was seen as necessary.

1.2.2 The structure of the Decision generally follows the sequence of the contents of the draft Rate Handbook. Chapter 2 deals with a general approach to PBR. Chapter 3 deals with establishing the initial rates. Chapter 4 discusses the annual rate adjustment mechanism. Chapter 5 deals with service quality performance under a PBR regime. Chapter 6 discusses Demand Side Management matters. The final chapter, Chapter 7, deals with implementation issues. This Decision should be read in conjunction with the draft Rate Handbook.

1.2.3 Copies of all the documents and submissions filed in the proceeding, together with a verbatim transcript of the hearing, are available for review at the Board's offices. While the Board has considered all of the documents and submissions, the Board has cited these only to the extent necessary to clarify specific issues on which it has made findings.

1.2.4 The Board has not amended Board staff's draft Rate Handbook as part of this Decision. The next version of the Rate Handbook, which will reflect the Board's findings, will be distributed following the issuance of the Decision.

1.2.5 In addition to revisions necessary as a result of this Decision, the Rate Handbook may in the future be revised to address Board policies, Codes, and guidelines which affect rates. Compliance with the Rate Handbook will be a condition of licences issued to electricity distributors.

<u>GENERAL APPROACH TO PBR</u>

2.

2.1.1 The following are extracts from the draft Rate Handbook regarding the objectives of PBR:

> *PBR provides the distribution utilities with incentives to operate efficiently and innovate. It also gives consumers appropriate price signals, and allows the sharing in the gains from more efficient production, consumption and innovation.*
>
> *PBR is a framework that permits greater pricing flexibility and allows the potential for higher profits based on superior performance than would a traditional regulatory framework such as cost-of-service...*
>
> *...PBR decouples the price that the utility charges for its service from its cost. Since price adjusts according to a simple formula, if the utility can reduce its costs by more than its consumer dividend, it can keep the cost savings in the form of higher operating profits. Thus, PBR provides strong incentives for utilities to find efficiencies in their operations, some of which are recaptured in the form of lower rates when the plan is revised...*

... to discourage utilities sacrificing service quality in pursuing the economic incentives, service quality performance measures are included in the PBR plan.

2.1.2 The draft Rate Handbook proposes a three-year first generation transition PBR plan with price caps for all Ontario electricity distribution utilities. It is also proposed that a mid-term review be held to design the second generation of PBR. While the regulatory mechanism would be reviewed at that time, it is proposed that the Board would also conduct a re-basing study to identify the level at which rates should be established for second generation PBR.

Positions of the Parties

2.1.3 In general, the adoption of PBR was acknowledged by parties to be the appropriate direction for the regulation of the restructured electricity distribution utilities in Ontario. OFA did not believe that regulation by the province of the electrical distribution utilities was necessary. Some parties (most notably Upper Canada and CAC) proposed that the implementation of PBR be delayed. CAC was concerned about getting the initial rates correct, while Upper Canada felt that PBR was not needed at this point as the distribution utilities are already efficient, implementation of a market-based rate of return and transition costs would dwarf PBR gains, and utilities are already in a period of volatility and transition. Upper Canada proposed suspending the implementation of PBR for two or three years.

2.1.4 With respect to the price cap proposal, while most parties did not object to its use some parties proposed alternatives. Frontier Economics on behalf of Mississauga et al argued that, for industries where there are many participating businesses, the use of a yardstick regulation mechanism would give greater incentive for efficiency. In addition, Frontier Economics held that the price cap mechanism, as proposed, gives no consideration to the circumstances of particular utilities. Sault Ste. Marie Hydro suggested that the price cap adjustment mechanism incorporate a growth factor to account for increased system demand. It was generally agreed by parties that a yardstick regulation mechanism be a goal of the second generation PBR plan.

2.1.5 Certain parties suggested that the proposed three-year term was too short to provide incentives to distribution utilities to achieve maximum productivity. Others commented that, because of the lack of experience with PBR, the three-year term would help limit possible "bad outcomes", that is either excessive earnings or financial hardship. Parties also asked the Board to provide further elaboration on second generation PBR with respect to both re-basing and service quality matters.

Board Findings

2.1.6 The Board notes that some parties questioned the purpose of embarking on a PBR regime. In its policy document on the electricity industry restructuring, Direction for Change, 1997, the Government proposed "to direct the Board to examine, advise on, and subsequently implement a performance-based approach to regulation that ensures efficiencies are achieved in the monopoly parts of the industry and results in benefits to customers. The Government's goal is tariffs that are as low as possible on a sustainable basis".

2.1.7 In its draft policy on Performance Based Regulation in October 1998, the Board stated its rationale for developing a PBR mechanism:

- With the passage of Bill 35, the Board will have the task of regulating a large number of diverse utilities within the province. Since PBR has the potential to provide an expedient mechanism for adjusting rates over time as circumstance change, it is expected to result in fewer rate reviews before the Board and, hence, a lesser regulatory burden.

- PBR can provide greater incentives for cost reduction and productivity gains compared to those available under traditional cost of service regulation while protecting the interests of customers.

- PBR would allow the Board to establish minimum service quality and reliability standards and require compliance with these standards.

2.1.8 The Board has broad discretion under the Act to employ any method or technique in discharging its responsibilities to set just and reasonable rates.

2.1.9 The Board confirms its position that PBR is the appropriate mechanism to be used in bringing the electricity distribution utilities under the authority of the Ontario Energy Board.

2.1.10 With respect to the arguments regarding the use of price cap for all the distribution utilities, while there may be alternative PBR mechanisms that may hold promise, the Board notes that the task forces indicated that, at this time because of lack of consistent data, insufficient time, and insufficient resources, it was not possible to pursue other mechanisms, such as the yardstick mechanism that was the preference of many parties. Further, the Board is of the opinion that price cap regulation for all the electricity distribution utilities represents a simple approach that will provide incentives for efficiency improvements and will at the same time provide the ability to maintain service quality over the course of the first generation PBR plan. The Board therefore adopts the price cap mechanism for first generation PBR.

2.1.11 With respect to the suggestion by some parties that the initial term ought to be longer than three years, the Board finds that the three-year term provides a fair balance of the risks of potential “bad outcomes” and sufficient time for the distribution utilities to gain experience with PBR. In addition, the three-year term would allow the collection of sufficient data for the Board and the industry to assess the various mechanisms and will establish a baseline for second generation PBR. The Board therefore concludes that a three-year first generation transition PBR term for years 2000-2002 is appropriate. Given the relatively short period of first generation PBR, the Board does not envisage the need to include any provision to allow utilities to exit the plan, commonly known as “off-ramp”.

2.1.12 On the issue of whether a growth factor should also be included in the price cap mechanism, the Board accepts Dr. Bauer’s testimony that a growth allowance is implicit in a price cap PBR regime and therefore explicit inclusion of a growth factor in the price cap formula is unnecessary.

2.1.13 The Board is not prepared at this time to elaborate on details for the second generation PBR plan, such as re-basing of rates, except to reiterate what is stipulated in the draft Rate Handbook that the utilities will be required to undertake cost allocation studies[8] to better align rates among customer classes with cost causation in second generation PBR. Further, the Board confirms the proposal in the draft Rate Handbook that Board staff should initiate a mid-term review to design the next generation of PBR.

2.1.14 By way of commentary, the Board observes that PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR, the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board.

[8] The Board distinguishes the terms 'cost of service' and 'cost allocation' studies in the following manner. Cost of service studies pertain to the determination of a total revenue requirement. Cost allocation studies deal with the allocation of the revenue requirement among customer rate classifications.

3. INITIAL RATES

3.1.1 This chapter deals with the determination of the initial rates to be used in the first year (year 2000) of the PBR plan and to which the price adjustment mechanism will apply in the subsequent two years (years 2001 and 2002).

3.2 UNBUNDLING

3.2.1 As the starting point for unbundling the existing distribution utilities' rates into distribution and cost of power rates, the draft Rate Handbook assumes that existing rates appropriately recover costs from each of the rate classes. With this premise, a simplified method of allocating the cost of power to each rate class is presented in the draft Rate Handbook so that an initial class revenue requirement can be constructed that preserves rate class revenue neutrality.

3.2.2 The draft Rate Handbook acknowledges that, ideally, cost allocation studies would be available to guide the unbundling process. However, the draft Rate Handbook also acknowledges that there is only a short time available before market opening and therefore new cost allocation studies may not be feasible. In such circumstances, the draft Rate Handbook presents a simplified model of cost allocation as a default. The draft Rate Handbook allows distribution utilities that have their own studies to use them as the basis for setting initial rates.

3.2.3 The draft Rate Handbook indicates that the distribution (wires only) rates must be separated (unbundled) from the cost of power rates. The cost of power rates prior to market opening will cover both the transmission and commodity costs, since these are currently both included in current wholesale rates. With market opening, a transmission charge and a commodity charge will replace the cost of power charge. In order to unbundle existing rates, the revenue requirement for each customer class must first be separated into distribution and cost of power revenue requirements. In unbundling the rates, the cost of distribution system losses are separated as well. Prior to market opening, the distribution system losses will be included in the cost of power. With market opening, the distribution system losses will be recovered through a separate charge.

3.2.4 The proposal regarding the distribution rate structure in the draft Rate Handbook is a two-part distribution rate: a monthly service charge ($/month) plus a variable or volumetric charge ($/kWh or $/kW). The intent of the volumetric rate is to provide intra-class equity related to differences in system usage. The proposed design uses the incremental distribution cost ("IDC") included in existing rates, net of system losses, to set the level of the volumetric charge.

3.2.5 The volumetric rate is based on the incremental distribution cost of $0.0062/kWh derived for residential customers in the 1980s. Appendix A to the draft Rate Handbook requires that distribution system losses be deducted from the IDC.

Positions of the Parties

3.2.6 Some parties questioned whether the current rates correctly reflect costs and whether they are therefore the appropriate starting point for the PBR regime.

3.2.7 Several parties (MEA, Upper Canada, OHSC, ECMI, FOCA, GEC, CAC) expressed concern that the unbundling model proposed in the draft Rate Handbook could cause undue rate impact within each customer rate class. This concern is related to the fact that a significant portion of distribution revenue will be recovered through the fixed service charge, rather than the volumetric charge. Additional concerns were raised about the validity of the IDC.

3.2.8 There was debate among parties as to whether losses were included or excluded from the $0.0062/kWh IDC rate. MEA commented that the proposed approach in the draft Rate Handbook of deducting losses from the IDC may amplify deficiencies in the IDC in the case of lower density/higher loss networks. That is, their true IDC would be higher than the $0.0062 value, yet deducting higher losses would further reduce this rate. MEA therefore suggested that the $0.0062 value be treated as a floor that could be raised by a certain percentage to reflect local costs. GEC suggested that losses were never included in the IDC so that it is inappropriate to deduct them.

3.2.9 GEC's consultant suggested that the IDC should at least be adjusted for inflation. Also, FOCA's consultant submitted analysis that suggested that the IDC used to determine the provincial average residential end rate could be almost twice the $0.0062/kWh rate.

3.2.10 Some parties expressed concern with the use of the residential IDC to establish volumetric rates for the remaining customer classes (general service, street lighting, sentinel lighting, and large use customer classes) since the $0.0062/kWh rate was derived for the residential class.

3.2.11 ECMI provided rate comparisons showing that low use customers in residential and general service classes would be subject to large rate impacts if a large proportion of the distribution revenue is collected in the form of a fixed service charge.

3.2.12 Certain parties (GEC, FOCA, Pollution Probe) were concerned about the environmental and energy efficiency effects of collecting a substantial amount of the distribution rate as a fixed service charge. These parties argued this rate structure would discourage energy conservation.

3.2.13 FOCA recommended that the monthly service charge reflect only customer specific charges such as meter reading, billing, and collection, and that all other costs be recovered in the volumetric component.

Board Findings

3.2.14 The Board is aware that the existing rates of the municipally-owned distribution utilities, as previously regulated by Ontario Hydro, are based on a utility average cost allocation model. The Board understands that, as a result of the use of the average cost allocation model, few, if any, distribution utilities have conducted their own cost allocation studies. The Board also recognizes the need for the distribution utilities to have unbundled rates in place by market opening and that this constraint makes it unrealistic to expect utilities to complete cost allocation studies prior to market opening. Therefore, the Board agrees that, as a default, the distribution utilities should be allowed to base their initial rates on existing rates.

3.2.15 However, the Board also recognizes the need for the distribution utilities to carry out cost allocation studies in order to ensure that rates for second generation PBR are based on cost causation principles. The Board therefore expects utilities to be prepared for a review of their individual cost allocation studies at the time of the mid-term review leading to the development of second generation PBR.

3.2.16 The Board notes that, while parties expressed concern with the use of a dated 1980s load research model as the default, no alternative study was available or prepared for the purposes of this proceeding. The Board notes that the two alternative approaches to unbundling existing distribution utility rates are to use utility-specific load research information or to use the 1980s load research model. To the extent that some utilities may choose to use their own load research information, the Board expects them to include such information in their filings with the Board.

3.2.17 GEC suggested that the IDC value of $0.0062/kWh does not include system losses. The Board notes that Ontario Hydro's Regulatory Application Guidebook describes local costs to include losses, incremental distribution costs and maintenance. It would appear that, in preparing the draft Rate Handbook, Board staff had incorrectly assumed that losses were included in incremental distribution costs.

3.2.18 The Board accepts that the use of a two-part rate structure consisting of a monthly service charge and a volumetric charge provides some revenue certainty for the distribution utility and, to the extent that IDC charges represent a reasonable reflection of the incremental cost of providing additional service, intra-class equity.

3.2.19 The Board however shares the concerns expressed by some parties as to the appropriateness of the proposed IDC value of $0.0062/kWh. For the purposes of first generation PBR, the Board concludes that it would be appropriate for the residential class to allow utilities to use their specific IDC level. The utility wishing to propose its own IDC level will be required to file appropriate justification. In the absence of a utility specific IDC level, the Board concludes that the proposed IDC value of $0.0062/kWh be used as the default value.

3.2.20 In either case, the volumetric charge (which is the same as the IDC in the absence of any other considerations) to be included in rates will have to consider the rate impact resulting from rate restructuring and the adjustments to the existing rates for purposes of establishing the initial rates for the first generation PBR plan. The Board's comments regarding mitigation of rate impact are set out later in this section.

3.2.21 The Board notes that the existing rates for the other (non-residential) rate classes were derived using this IDC value of $0.0062/kWh. The Board shares parties' concerns that this value may not be appropriate for these classes. Further, Board staff have alerted the Board that using the $0.0062/kWh value as the volumetric charge may result in revenue recovery in excess of 100 percent of the general service revenue requirement. In the absence of a utility-specific study, to provide for a consistent approach in designing a two-part rate structure among the various classes the Board has asked Board staff to explore the use of the ratio of the monthly service charge revenue to volumetric rate revenue for residential customers as a guide to determining the split between the revenue to be generated from the volumetric charge and the monthly service charge for the remaining customer classes. The method developed to address the above will be included in the Rate Handbook.

3.2.22 The Board also shares the concerns expressed by some parties about using a single monthly service charge level for all customers in the general service class regardless of customer size. To address this concern, the Board will include in the Rate Handbook a method for differentiation of monthly service charges for general service customers for three sub-groups: up to 50 kW (non-demand metered), equal to or greater than 50 kW, and intermediate use which is an optional rate classification for general service customers with demand greater than 3000 kW. The rate design should ensure revenue neutrality for each of these general service sub-groups.

3.2.23 The Board anticipates that the utilities will tend to set the volumetric charge at the minimum possible level and the monthly service charge at a higher level to minimize the risk of revenue shortfall. The Board shares certain parties' concerns regarding rate impact from moving to a rate structure with the proposed levels of monthly service charges. The Board observes that the rate impact could be large for low use customers. The Board expects that distribution utilities should take these impacts into consideration when setting the service charge and volumetric charge levels. The Board will require utilities to employ appropriate measures to mitigate the impact on low use consumers in each customer sub-group/rate class (for example, residential customers consuming less than 250 kWh per month). As a guideline, the increase in the total electricity bill resulting from rate restructuring for these customer groups should not exceed 10% on an annualized basis. For purposes of calculating the rate impact, the utilities shall use the current wholesale cost of power rates to determine the commodity component of the total customer bill amount.

3.2.24 Some parties expressed concern that a variable rate based on an IDC level of \$0.0062/kWh is too low to provide an incentive for energy efficiency. The Board notes that there is insufficient evidence to determine the impact that the rate redesign will have on energy efficiency activity. In any event, the Board notes that the delivery component charges are not the major components of the total bill (distribution plus cost of power). Further, the Board's findings will likely result in higher volumetric charges than those proposed in the draft Rate Handbook.

3.2.25 The Board understands that revenues from miscellaneous distribution related service charges, such as disconnection and reconnection charges, non-payment of account charges, and rental fees are excluded from existing distribution service rates and are collected through separate charges. As such, these charges are not covered by the price cap mechanism and any changes to these charges will require explicit Board approval.

Minimum Bill Provision

3.2.26 The draft Rate Handbook makes no reference to minimum bill provisions. In their opening remarks in the oral phase, Board staff noted the need for minimum bill provisions in the Rate Handbook and referenced the existing Standard Application of Rates ("SAR") document for guidance on the development of minimum bill provisions.

3.2.27 The SAR states that minimum bills should be established according to existing guidelines developed by Ontario Hydro. The existing guidelines on minimum bills require the level for the residential class and non-demand metered general service customers to be established so that it does not exceed 25 percent of the residential bill at a consumption of 250 kWh. For general service customers with demand meters, the minimum bill is either equal to the residential minimum bill plus the allowance for transformers supplied at less than 115 kV per kW applied to the maximum kW in excess of 50 kW in the previous eleven months, or the transformer allowance per kW of the maximum demand created in the previous eleven months. The existing guidelines state that the existing minimum bill provision is based on the avoided cost of supply to the average customer, including the cost of the meter, meter reading, and carrying costs of any utility-supplied service drop normally dedicated to one customer. Even if a customer takes no power at all, the minimum bill applies.

3.2.28 The Board questions whether the provision for a minimum bill is required under a two-part rate structure with a fixed charge and a volumetric charge, given an appropriate degree of flexibility setting the levels of these charges. The Board is prepared to accept the use of a minimum bill for distribution services for first generation PBR for those utilities that currently have a minimum bill provision, where the utility believes it is necessary to retain such a provision in order to mitigate the rate impact on customers. However, any such requests must reflect the separation of distribution rates from cost of power. The Board expects that the need to have a minimum bill provision in a two-part rate structure will be reviewed for second generation PBR.

Unbundling and Rate Design Model

3.2.29 Appendix A of the draft Rate Handbook includes an illustration of the unbundling and rate design methodologies proposed by Board staff.

3.2.30 The availability of a spreadsheet model for unbundling and rate design could be of assistance to utilities in developing their proposed initial rates. In that regard, the Board understands Board staff are already in the process of developing such a model. The Board expects Board staff to ensure that the model reflects the Board's findings in this Decision, including the Board's concerns regarding rate impact.

3.3 ADJUSTMENTS TO UTILITY REVENUE REQUIREMENT

3.3.1 In establishing initial rates, the draft Rate Handbook stipulates that certain adjustments to current rates may be warranted, such as an allowance for market-based returns, which includes payment in lieu of income taxes, or proxy taxes, and for prudently incurred costs associated with the transition to the new market structure.

Market-based Return

3.3.2 The draft Rate Handbook proposes that distribution utilities would fall into four categories for the purpose of establishing a deemed capital structure. The draft Rate Handbook identified four levels of risk classification based on rate base size.

3.3.3 In order to calculate the market-based return, a rate base has to be determined. The total rate base equals total deemed capitalization of the utility. The cost associated with the debt component of the deemed capital structure is included in the draft Rate Handbook as part of the market-based rate of return revenue requirement ("MBRR") formula. The cost rate associated with the common equity component that was used in the draft Rate Handbook was 9.75 percent. The illustrative values for the cost of debt and common equity were based on a forecast that long-term Canada bond yields would average between 5.95 percent and 6.0 percent during year 2000, implying an equity risk premium of 375-380 basis points.

3.3.4 The methodology for determining the initial rate of return on common equity and the annual setting of Return on Common Equity ("ROE") is based on the methodology used by the Board in regulating natural gas utilities and was also applied in setting the transitional rates for OHSC (RP-1998-0001). The actual values of both the debt rate and the return on common equity will be calculated by the Board using data from December 1999.

3.3.5 The Board notes that certain parties submitted that the implied equity risk premium that underpins the 9.75 percent[9] rate of return used in the draft Rate Handbook is inadequate. The Board has not been persuaded that the implied equity risk premium contained in the 9.75 percent proposal is unreasonable. In finding so, the Board has considered the authorized rates of return for the gas utilities in Ontario as well as the authorized rate of return for OHSC. As for the argument by Enbridge Consumers that the single risk premium may not adequately compensate the higher risk faced by a smaller electric utility, the Board notes that the differentiation in the capital structure contained in the draft Rate Handbook based on rate base size makes allowance for the perceived differences in risk.

3.3.6 To determine the level of return, an initial rate base must be established. Such rate base must be related to the "wires only" activities. The Board is aware that some distribution utilities have already been incorporated and therefore have

[9] The updated rate of return on common equity to be used in establishing the initial rates may change to reflect the forecast values of the long-term Canada bond yields based on data for December 1999.

established their "wires only" activities, others have not. In either case the Board needs the information to establish the "wires only" rate base.

3.3.7 If the utility has undergone incorporation and separation of regulated and competitive activities when an application for initial rates is filed, the establishment of the utility rate base will be reviewed by the Board to ensure that there is compliance with the Board's guidelines with regard to the definition of distribution activities. If incorporation is not completed at the time of filing, a proforma projection should be prepared. In either case, the utility must present the rate base both before and after separation. The amounts removed from the integrated rate base, actual or notional, should be based on net book value.

3.3.8 In order for the Board to determine the adjustment required to reflect a market return on rate base, the Board requires information on the return achieved. The Board has determined that it would be appropriate to use year end 1999 data for determining the initial rate base.

3.3.9 In comparing the after-tax market return in establishing the initial rates with the achieved 1999 return, the Board's implicit assumption is that the integrated utility earned the same rate of return on all its business activities. The Board recognizes that there may have been differences in the contribution of different activities to the overall return but, in light of the complexities and substantial effort and time required to address such matters, the Board has determined that this assumption is reasonable in order for the distribution systems to be able to have initial rates in place before market opening.

3.3.10 The Board is cognizant of the fact that in the absence of shareholders, and through the previous regulator's cap on working capital levels, many of the municipally-owned electricity distribution utilities have historically earned below market-based returns. Upon corporatization, with the municipalities as their shareholders, the distribution utilities may wish to propose rates to target returns up to the allowable MBRR. Under this scenario, the Board is concerned with the resulting rate impacts in the establishment of the initial rates.

3.3.11 Throughout this proceeding the Board has heard from intervenors that ratemaking should as much as possible be a local decision. The Board agrees. The decision to implement full MBRR for all components of the rate base is a decision that falls upon the management, directors and the shareholders of the local utility, and the Board will require the utility to inform and explain the rate changes to their customers as well as the reasons thereof.

3.3.12 Based on the report of the distribution rates task force, implementation of a market-based return and taxes may result in an average increase on revenue required for distribution and cost of power of 6.1 percent. The revenue requirement for some utilities would be lower than that under the existing rates. For the majority of utilities the revenue requirement would be higher. In order to mitigate rate impact in the implementation of the initial rates, the draft Rate Handbook proposes that a deferral mechanism be put in place. Subject to the Board's findings later in this chapter that the initial rates will not incorporate any transition costs, the Board accepts the deferral mechanism proposal in the draft Rate Handbook.

3.3.13 Given the flexibility afforded to the utilities through the deferral mechanism, the Board will expect the utilities to take advantage of that flexibility and to propose initial rates that will not result in undue rate impacts. In its review of rate proposals and under its authority to fix rates, the Board will either seek revised proposals or fix the rates itself should it be found that rate impacts have not been adequately addressed.

Treatment of Contributed Capital

3.3.14 The draft Rate Handbook stipulates that:

> *Contributed capital collected under Ontario Hydro's regulatory regime and currently included in rate base will remain in rate base. The distributors will continue to earn a return on the contributed capital portion of the existing rate base until these assets are fully depreciated. However, the rate of return that will be applied to this component of the*

rate base will be the 1994-1999 average equity rate of return for the utility, subject to a zero per cent floor and a 9.75% maximum.

Going forward, under the Board's regulation, contributed capital collected by the electric distributors will not be included in rate base. As a result, the distributors will not be earning a return on the contributed capital collected in the future, nor will they be allowed to charge the associated depreciation expense to operating expense.

3.3.15 Board staff proposed this approach in the belief that it gives consideration to the regulatory framework that the distributors were subject to prior to the Board's assumption of this regulatory oversight role. As well, Board staff believed this approach leaves both the distributor and its customers no worse off than they were under the previous regulatory regime.

3.3.16 Prior to 1994, under the regulatory oversight of Ontario Hydro, municipal electric utilities were not allowed to include contributed capital (otherwise known as contributions in aid of construction) collected from developers and other new customers in the utility rate base. The asset base for revenue requirement purposes was the net book value of fixed assets minus the unamortized balance of the contributed capital associated with those fixed assets. In addition, contributed capital was accounted for as a deferred credit that was amortized and credited to operations, in effect offsetting the depreciation charge to operations associated with assets financed through contributed capital.

3.3.17 Ontario Hydro reviewed its policy in 1993 and concluded that exclusion of assets financed through contributed capital from rate base and depreciation expense from operating costs had the potential to cause distortions in the application of rate of return on rate base regulation. The stated rationale was that utilities with a high proportion of contributed capital would be unable to generate sufficient funds from operations for normal reinvestment requirements in the utility, and the uniform application of Ontario Hydro's regulatory guidelines among utilities was in jeopardy of being inconsistently applied.

3.3.18 Accordingly, commencing in 1994, Ontario Hydro's accounting policy on contributed capital was changed. Contributed capital was included in rate base thereby earning a return, and the associated depreciation expense was included in the utility annual revenue requirement.

Positions of the Parties

3.3.19 The parties to the proceeding were generally divided on the treatment of historic contributed capital, and differing positions were offered on the allowable rate of return on contributed capital.

3.3.20 A large group of intervenors (Mississauga et al, Upper Canada, Nepean, The Coalition, ECMI, PSEG, GEC) argued that historic contributed capital should attract a full market-based rate of return. The group generally held that no valid argument could be made to treat one form of capital in a different way from another since, in one way or another, all of the utility's assets were financed by the ratepayer. The group also held that Board staff's proposal was essentially tantamount to writing down the value of the utility's assets. Nepean contended that, since its average historical return in the 1994-1997 period was negative, the proposal essentially removes contributed capital from rate base in its case. The consultant for Mississauga et al, Frontier Economics, submitted that the cost of capital services used in distribution services is based on a measure of the market cost of capital for the regulated entity and that no other measure will produce economically efficient prices. Mississauga et al interpreted the Government's 1997 White Paper, Direction for Change, and the Act, as giving the right to municipalities, as owners, to structure the new utility corporations however they see fit. This right includes the ability to value, for all business purposes, the assets being transferred into the new corporation. Mississauga et al also expressed concern that the proposed treatment of contributed capital will have a serious impact on debt repayment through the loss of transfer tax and payments-in-lieu of taxes revenues.

3.3.21 Energy Probe submitted that contributed capital should be treated no differently than the rest of rate base, and that a common recovery policy be applied to both forms of capital. However, Energy Probe did not believe that a market-based rate of return should apply to any investments made by municipal electric utilities ("MEUs") when they were operated as "co-ops". Therefore, in its view, historic contributed capital and all other capital should not attract a market-based rate of return.

3.3.22 FOCA and VECC submitted that historic contributed capital should be removed from rate base. VECC stated that Board staff's proposed treatment of historic contributed capital is inconsistent with the Board staff proposal to exclude future contributed capital from rate base and with standard regulatory practice. VECC noted that the standard practice in other Canadian jurisdictions is to treat contributed capital as a source of funds that does not attract a return and that the Board itself uses this approach in the regulation of the Ontario natural gas distribution utilities. Both VECC and FOCA argued that, in the case of contributed capital, MEUs have not invested anything themselves and have not assumed the risk of an accumulating debt obligation. If customer contributed capital is included in the rate base, customers would essentially be paying twice for the assets being used to serve them; once through the contributed capital they have provided and again through the distribution charges they pay. VECC and FOCA argued that all customer contributed capital should be excluded from the rate base.

3.3.23 CAC and Chatham-Kent Hydro accepted Board staff's proposed treatment of historic contributed capital. Chatham-Kent Hydro qualified its support for the use of the1994-1999 average equity rate of return with the proviso that the rate of return be on an after tax basis. Dr. Bauer, on behalf of CAC, qualified his support stating that the proposal is a sensible compromise that avoids regulatory recontracting. However, he argued that, from an economic efficiency view, contributed capital should be removed from rate base as the use of contributed capital diminishes the need for the utility to raise debt or equity capital. He noted that, while the capital contributions are used to augment the capital basis of the utility, there is no need to compensate investors for their time-preference or risk. Dr. Bauer also expressed the view, as did certain other parties, that inclusion of contributed capital in rate base would lead to double-payments. However, he stated that accepting a specific notion of fairness, namely not to change past arrangements, the Board staff proposal is acceptable.

3.3.24 CAC took issue with the legal argument put forth by Mississauga et al. CAC argued that nowhere in the legislation or the White Paper are absolute rights or sole discretion conveyed to municipalities or MEUs. CAC argued that section 128(2) of the Act means the powers of the Board prevail over any by-law passed by a municipality. CAC submitted that the Board has the jurisdiction to value contributed capital as part of the process of establishing a mechanism for the determination of just and reasonable rates, and that the Board should do so in the exercise of that jurisdiction. PWU submitted that, for the purpose of ratemaking, the Board's statutory authority is broad and unfettered, and not bound by any valuation of assets made by any municipality in a transfer by-law.

Board Findings

3.3.25 The Board notes that no parties questioned the Board staff proposal that future capital contributed on or after January 1, 2000 not be included in rate base. The Board confirms this approach and this will ensure similar treatment between gas and electricity distribution utilities in the future.

3.3.26 In evaluating the alternative treatments of historic contributed capital there are two questions that need to be addressed by the Board. The first is whether or not historic contributed capital should be included in rate base; the second, if included, what rate of return should apply.

3.3.27 The Board has been persuaded by the arguments that historic contributed capital for electricity distribution utilities is a unique case. The Government indicated in its White Paper that MEUs will be put on a commercial footing consistent with other commercial businesses operating in Ontario. The Government also indicated that, in reviewing local distribution tariffs, the Board would be expected to make an appropriate allowance for a normal rate of return. In establishing the new utilities, the assets of the local municipal utility have been or will be transferred to the municipality as the shareholder. From a regulatory point of view, the new shareholder of these assets will have the rights and responsibilities accorded to them under the applicable legislation. This includes a fair rate of return on the total capital employed.

3.3.28 The Board also notes that there are economic and fairness arguments in favour of not distinguishing the two sources of capital. Differentiating a source of capital for the purpose of pricing such capital at different rates would lead to both inequities among utilities and would result in inappropriate market pricing signals for the services provided by the distribution companies. On the first point in particular, the Board is aware of the wide differences among utilities with regard to the relative portion of historical contributed capital to the total capital employed by the utility. As some parties noted, all of the capital has been contributed by the ratepayers whether by means of contributed capital or through rates. To introduce a policy that would allow a return to the utilities that had funded their capital through rates rather than contributed capital, but to deny this opportunity to those utilities who had for the most part used development charges/contributed capital would, in the Board's view, put the utilities on an unequal commercial footing in this regard.

3.3.29 Given the above, the Board concludes that historic contributed capital should be included in rate base and that the same rate of return should apply to all capital, exclusive of future contributed capital, employed by the distribution utility.

Transition Costs

3.3.30 The draft Rate Handbook indicates that the initial rates may, subject to certain criteria such as causality, materiality, management's inability to control and prudence, include costs associated with the transition to the new market structure. The Handbook further states that all such costs must be specifically identified and justified.

Positions of the Parties

3.3.31 Parties' arguments generally addressed transition costs together with their argument regarding Z factors as presented in the draft Rate Handbook. Some parties expressed concern about the reasonableness of including transition costs in rates. Parties also suggested that transition costs claimed for inclusion be audited and benchmarked.

Board Findings

3.3.32 The Board concludes that transitional costs should be classified into two categories. The first category is costs related to corporate reorganization and to the transfer by-law whereby the municipal corporation acquires the assets of the municipal electric utility. The second is costs related to the business re-engineering of the incorporated distribution company to conform to the new business orientation and requirements of a "wires only" company.

3.3.33 With respect to the costs of corporate reorganization, the Board notes that, under the Act, the municipalities are the shareholder of the distribution utilities. Along with the benefits of such ownership, there are also responsibilities. These responsibilities include bearing the cost of corporatization and corporate reorganization. In dealing with such issues in the regulation of the gas utilities, the Board has generally found such costs to be the responsibility of the shareholder. The Board therefore finds that this category of costs should be to the account of the shareholder.

3.3.34 With respect to the business re-engineering costs, the Board concludes that these costs will likely be incurred over a period of time that will likely extend beyond the date of the initial rates being in place. Therefore, the Board finds that these costs should be deferred and dealt with as part of the Z factor mechanism included in the price cap formula. The Board accepts the proposal in the draft Rate Handbook that such costs will have to be specifically identified, justified and meet the four criteria tests mentioned above. Further, the Board will not require that specific applications be made for establishing deferral accounts in respect of these costs; this Decision should be viewed as the only regulatory instrument required to establish such accounts.

3.3.35 On the basis of the above discussion and findings, the Board will not permit incorporation of any transition costs for purposes of establishing initial rates.

ANNUAL RATE ADJUSTMENTS

4.

4.1.1 The draft Rate Handbook proposes a price cap mechanism to adjust the distribution rates for the second and third years of the first generation PBR term. The formula for the price cap adjustment includes an input price index ("IPI"), a productivity factor ("PF"), and an adjustment factor ("Z factor") to reflect extraordinary items. The Board deals with these matters in this chapter.

4.2 INPUT PRICE INDEX

4.2.1 The draft Rate Handbook states that:

> *The purpose of the input price index adjustment is to allow each utility the discretion to pass through changes in the prices of the inputs it purchases - at a rate determined by the typical distributor's experience with input prices during the previous year. A distributor whose own input prices rose less than the input prices of the typical distributor would increase its earnings if it chose to adjust its own price cap by the full amount...This input price index is specific to the electric distributors in Ontario. The index comprehensively measures changes in the prices of inputs employed by the distributors including capital, labour and materials.*

Positions of the Parties

4.2.2 Certain parties (Upper Canada, OHSC, Chatham-Kent Hydro) argued that an existing index, such as the Consumer Price Index ("CPI"), be used rather than the proposed IPI. These parties were concerned about the lack of transparency and untried nature of the IPI. Chatham-Kent Hydro was concerned about relying upon a newly created factor that is not commercially tracked or forecasted, when other indexes such as CPI and Gross Domestic Product Price Index ("GDPPI") are commonly available. Additional concerns were expressed about the ability of the Board to deliver an IPI calculation to all utilities by February 15 based on a filing deadline of February 1. OHSC was concerned about the variability of IPI and questioned the ability of the capital portion of the index to measure the actual costs that utilities face. Upper Canada had similar concerns and their consultant pointed out that CPI is used in other jurisdictions' PBR plans, is simple, and yields real price declines to distribution consumers.

4.2.3 Mississauga et al consultant, Frontier Economics, submitted that the choice of an inflation index is essentially irrelevant. Frontier Economics acknowledges that there may be certain advantages to using an input price index if the productivity measure is particularly volatile. In general, however, Frontier Economics held that the choice of an index is a trivial issue in incentive regulation but that such choice would impact the setting of the productivity factor.

4.2.4 Dr. Bauer, on behalf of CAC, held that, in calculating input price inflation from industry data, the proposed input price inflation measure violates the salient principle of incentive regulation that the plan parameters be derived from data external to the regulated utility. He noted that this is somewhat mitigated by the fact that there are a large number of utilities and no individual utility is able to influence the overall index unduly. Nonetheless, he felt that there may be an incentive for utilities to exaggerate cost data but allowed that this risk can be reduced by strict auditing requirements.

4.2.5 Energy Probe supported the use of the proposed input price index rather than CPI.

Board Findings

4.2.6 The Board has been presented with two alternatives regarding the price index adjustment. The first is the proposal made by Board staff in section 4.2 of the draft Rate Handbook. Board staff have outlined an input price index specific to Ontario electric distribution utilities that measures changes in the prices of inputs employed by the distributors, including capital, labour and materials. The alternative proposal was to use an economy-wide index such as CPI.

4.2.7 The Board notes the reasoning behind the Board staff proposal. The proposed index compares the prices of the factor inputs (capital, labour, materials) in any given year with a base year in order to determine an industry specific input price index that is reflective of the input costs of Ontario electricity distribution utilities. One major shortcoming of the CPI, highlighted by Board Staff, is that it does not measure changes in the price of capital, which is crucial in determining the appropriate change in input prices for capital intensive operations such as electricity distribution utilities. CPI is also influenced by factors such as changes in consumption taxes and food prices, which have no effect on the input prices faced by electricity distribution utilities.

4.2.8 The Board notes the parties' perception that the capital price portion of the index fluctuates unduly and may not measure the actual costs electricity distribution utilities face. The Board recognizes that Board staff proposed a user-cost of capital approach to determining the price of capital. In this approach, the cost of using a unit of capital is the opportunity cost of the capital including depreciation. The opportunity cost is represented by the interest forgone by having resources committed in the form of the asset. Board staff have used the 10 year Canada Long Bond Rate as the interest rate, a widely accepted method in setting a risk-free rate of return. The Board accepts this as an appropriate approach. The main purpose in moving towards PBR is to give the distribution firms the same price and cost signals as faced by unregulated companies. In addition, the industry IPI serves as a benchmark that the utilities can aim to outperform, through superior procurement and capital financing strategies.

4.2.9 In accepting the IPI approach, the Board has considered criticisms that utilities are constrained by the existing cost and term of their debt obligations, that is, the embedded cost of debt. Competitive companies have the opportunity to access capital markets when it is in their interest to do so. The Board accepts that PBR is intended to provide incentive for this behaviour. Even though the price cap adjustment to the rates will not apply until 2001, it is expected that, in the meantime, utilities will be making their capital financing decisions mindful of the application of the IPI to their operations and rates.

4.2.10 The Board also considered the criticism by some intervenors that the IPI could be influenced by the collusive activities of some distributors. In light of the fact that there are over 250 utilities in the province, the Board does not consider this a valid criticism. In addition, the Board notes that much of the data used to calculate the IPI is obtained from sources external to the utility. The Rate Handbook will include the sources of data used to derive the IPI. Going forward, the calculation of the IPI will be made from data available from external sources and from the filings by the utilities. This should address the parties' concerns regarding transparency.

4.2.11 However, the Board shares the concerns expressed by some parties regarding the ability of the industry to cope with the volatility of the IPI from year to year. In the Board's view, such volatility will be better managed as the industry gains experience with PBR. The Board recognizes that utilities may require a transition period before implementation of the IPI. The Board notes that the source of the volatility comes mainly from the capital cost component. In order to mitigate potential volatility in the IPI in the first generation PBR, the Board finds that the changes to the cost of capital component of the IPI will be limited to one half of the observed change. The Board recognizes that this is an arbitrary number but is of the view that it will directionally address concerns regarding year to year volatility.

4.3 THE PRODUCTIVITY FACTOR AND SHARING

4.3.1 The draft Rate Handbook states that:

> *The purpose of the productivity factor is to account for the downward influence on the price of a utility's product from gains in efficiency broadly considered...TFP* [total factor productivity] *has been used extensively in the application of PBR in many regulated industries, including electric. The task forces and Board staff reviewed many of these applications and the underlying approaches...the plan allows utilities to select the particular productivity factor from a set of six that it believes best reflects the combination of circumstances, opportunities, risks and rewards facing the utility.*

4.3.2 The draft Rate Handbook sets out the following menu of options for the relationship between productivity factor and rate of return on common equity ceiling.

Selection	Productivity Factor (percent change per year)	ROE Ceiling (Percent)
A	1.25	10
B	1.50	11
C	1.75	12
D	2.00	13
E	2.25	14
F	2.50	15

4.3.3 The figures shown as the ROE Ceiling are subject to change from year to year to reflect annual adjustments to the Board-approved market rate of return on common equity. Returns achieved up to those levels are to the account of the shareholder. Returns achieved above those levels would be returned to customers.

4.3.4 Research over the 1988 to 1997 time period as documented in the draft Rate Handbook found that the average annual change in TFP across Ontario distributors, based on a sample of 48 distributors, was approximately one percent. The PF value of 1.25 was set as the default value including a "stretch factor" of 25 basis points.

Positions of the Parties

4.3.5 Discussion by the parties fell into three general categories: the default PF value, the relationship between PF and ROE, and the concept of earnings-sharing.

4.3.6 A number of parties (OHSC, Upper Canada, The Coalition, Enbridge Consumers, MEA, Toronto Hydro) felt that the default PF value was too high. Some pointed out that the ten-year historic average annual TFP is only 0.86 per cent. In addition, it was argued that there may be a correlation between growth in output and growth in TFP that may bias the TFP in favour of high growth MEUs, so that low growth MEUs are disadvantaged. There was also concern expressed that distributors who have recently increased efficiency would be disadvantaged relative to those who had not.

4.3.7 Some parties (Mississauga et al, OHSC, Upper Canada) were concerned about the methodology chosen and the inability to check the data used by Board staff and its consultants in reaching their conclusions. In addition, Mississauga et al submitted that the foundation of the default value of 1.25 percent is subjective and its impact is unknown, and suggested a default PF in the area of 0.5 percent. Certain parties (Enbridge Consumers, The Coalition, Upper Canada) argued that only about one-third of a utility's total costs are controllable. Enbridge Consumers suggested a PF in the order of 0.3 percent, which would require an Operating and Maintenance Expense annual productivity gain of approximately 0.7 to 1.2 percent.

4.3.8 Dr. Bauer, on behalf of CAC, submitted that it cannot be concluded without further evidence that higher past productivity gains cannot be continued in the future. Noting the ten-year annual average TFP of 0.86 percent and the achievement of approximately two percent in the last five years, he contended that the chosen range of PF values reflects the lower boundary of reasonable values, suggesting that an upward shift by several tenths of a percentage point would be justified. In his view, to compensate for the past monopoly behaviour of the industry, it would be appropriate to include a stretch factor in the area of 0.5 to 1.0 percent. Energy Probe suggested that the sample collected by Board staff underestimates the potential for productivity improvement.

4.3.9 Some parties cautioned against a “one size fits all” approach. Specifically, Toronto Hydro suggested that a utility size-specific menu be available.

4.3.10 Certain parties believed that there is no economic basis for the PF-ROE ceiling schedule, and that there is no analytical basis for the proposed linear relationship between the PF and ROE ceiling. Mr. Todd, on behalf of VECC, posited that the PF-ROE menu does not provide an adequate incentive for a distribution utility to select a productivity target that realistically reflects its achievable productivity gain. He suggested that the proposed menu would encourage a utility to choose the lowest PF. He further suggested that an earnings-sharing mechanism can overcome this shortcoming. Some parties submitted that the proposed menu is too complex. Enbridge Consumers suggested the replacement of the proposal with a single PF and an earnings-sharing mechanism. Several parties (Toronto Hydro, OHSC, MEA) suggested that the ROE ceiling be averaged over the PBR term rather than calculated annually.

4.3.11 Several suggestions were made with regard to possible earnings-sharing mechanisms, including a sharing over any menu adopted by the Board or sharing over the ROE ceiling with or without a deadband. A sharing split of 50/50 was presented as a possible option. Some parties proposed that any sharing mechanism should be symmetrical, others suggested that the differential sharing levels be dependent on the level of ROE and productivity factor chosen.

Board Findings

4.3.12 In assessing the issues raised, the Board's conclusions have been influenced by the scope and objectives of a first term PBR. In this regard, the Board favours a model or methodologies that are easily understood and implementable, while at the same time providing incentives to the utilities to make productivity improvements.

4.3.13 The Board acknowledges the concerns expressed by parties regarding the unnecessary complexity encompassed in the proposed menu. The Board also notes the comments by some parties that the default productivity level would be the preferred choice of most utilities therefore placing into question the effectiveness of the proposed menu. The Board has assessed this concern against the arguments by some parties that a "one size fits all" approach should not be adopted by the Board. On balance, the Board concludes that the proposed menu approach should for first generation PBR be replaced by a single productivity factor for all utilities, combined with an earnings-sharing mechanism as proposed by some parties.

4.3.14 The Board therefore must first find the appropriate level of the productivity factor. The Board notes the information provided by some distributors that doubling the assumed productivity factor would result in a rate of return on common equity adjustment of approximately 40 basis points. Clearly, while the choice of the appropriate level of a productivity factor is important, its precise level is not of critical importance to the financial integrity of the utility. In the transition period for the electricity distribution utilities, there will likely be more critical considerations that may affect their profitability.

4.3.15 Having rejected the proposed menu in which the 1.25 productivity factor was the minimum of all options, the Board is concerned that in the absence of a menu, which incorporated higher levels, the 1.25 level no longer represents a reasonable base level to apply to all utilities. The Board notes that the default value is comprised of an average of 0.86 percent rounded by Board staff to a one percent productivity level achieved over a ten-year period plus a stretch factor of 25 basis points. The Board accepts 25 basis points as a reasonable stretch factor for purposes of first generation PBR. However, in the Board's view, the base productivity factor ought to be adjusted upward. In assessing a reasonable level for that base, the Board notes that, on the basis of the information provided in the proceeding, the achieved annual average productivity growth for the sample of 48 electric utilities was 0.86 percent for the most recent ten-year period and 2.05 percent for the most recent five-year period. The Board notes the arguments by certain parties that the most recent five-year period ought not to influence the Board's deliberations on the grounds that this period was not representative. Nevertheless the Board considers that some recognition must be given to the results achieved in the most recent five-year period. The Board has therefore adjusted the base productivity factor by giving a weight of two-thirds to the ten-year average result and one-third to the five-year average result. The Board therefore finds 1.5 percent as the appropriate productivity factor, inclusive of a stretch factor of 0.25 percent.

4.3.16 The Board has also considered the numerous presentations made in support of a sharing mechanism for earnings beyond the ROE ceiling. Elsewhere in this Decision the Board has dealt with the adjustment necessary to determine the initial ROE for the establishment of initial rates. The ROE representing the market-based rate of return for the second and third years of the PBR term will be determined in accordance with the Board's guidelines for determining the rate of return on common equity. To ensure that no excessive leveraging occurs, the Board expects that the actual proportion of the common equity component will not be materially lower from that deemed by the Board. The equity risk premium shall first be determined as discussed in Chapter 3 of this Decision.

4.3.17 The Board is of the view that the shareholder should retain a portion of the excess earnings over the ROE ceiling for the first PBR term. In considering all the alternatives proposed by the parties, and in light of the Board's findings with respect to the proposed menu, the Board finds that the excess earnings (after tax) resulting from any difference between the achieved and the Board-specified rate of return on common equity will be shared equally between the shareholder and customers.

4.3.18 The Board is of the view that the 50/50 sharing will provide sufficient incentive to encourage utilities to pursue productivity improvements above that included in the productivity factor. This sharing mechanism is set for first generation PBR and the issue of earning-sharing and productivity factor(s) will be subject to review for second generation.

4.3.19 As to the method for returning any excess earnings to the ratepayers, the Board accepts the provisions stipulated in the Supplement to the draft Rate Handbook dated August 12, 1999. These provisions allow for the excess earnings to be used as an offset to other charges, such as Z factors and deferral account balances, and if there are any remaining over-earnings these should be returned to ratepayers as a one-time rebate.

4.4 THE Z FACTOR

4.4.1 The draft Rate Handbook stipulates that:

> *A Z factor has been incorporated into the PBR rate mechanism to address extraordinary events and transition costs. In order for costs to be included in the Z factor, the costs must satisfy four tests:*
>
> - *Causation ....*
> - *Materiality...*
> - *Inability of Management to Control...*
> - *Prudence...*
>
> *The Board reserves the right to review the amounts claimed under the Z factor or transition cost treatment at any time during the term of the PBR plan*.

Positions of the Parties

4.4.2 Parties' arguments generally addressed transition costs together with their argument regarding Z factors. The Board has dealt with the issue of transition costs earlier in Chapter 3 of this Decision. The Board has attempted to summarize in this section its understanding of the parties' positions on Z factors.

4.4.3 VECC suggested that Z factor costs be benchmarked on a dollar per customer basis to avoid excessive costs and to streamline the process for determining prudence. It also suggested that the review process include public review. VECC and CAC suggested that any tax or accounting changes or changes of a legislative or judicial nature that affected the entire economy should not be eligible as a Z factor. VECC further suggested that if a distribution utility incurs costs in the anticipation of future benefits as a result of judicial or legislative actions, such costs should not be eligible as Z factors. CAC also proposed that Z factors be more narrowly defined and proposed amounts be audited. Energy Probe was generally opposed to all Z factors.

4.4.4 There was a suggestion by some parties that Demand Side Management ("DSM") could be incorporated into a price cap by means of a Z factor.

Board Findings

4.4.5 In Chapter 3 of this Decision, the Board categorized the transition costs into those related to corporate reorganization and to the municipal transfer by-law and those related to the business re-engineering of the incorporated distribution utility. The Board found only the latter to be eligible for inclusion in rates through the Z factor mechanism.

4.4.6 With respect to the suggestion of benchmarking Z factor costs on a dollar per customer basis, while this suggestion may have merit in the future, based on the information provided in this proceeding the Board has not been persuaded that this approach is workable or appropriate at this time. In the absence of better information the Board is concerned that adoption of such a suggestion would unduly disadvantage small utilities.

4.4.7 With respect to the suggestion that more precise definitions be provided of what would constitute Z factors, the Board questions the plausibility of the suggestion. The very nature of a Z factor is that it must be extraordinary, unpredictable and unmanageable. Further, the Board is concerned that it does not create the opportunity for utilities to game the system by diverting costs that should be part of the normal operations of the company into a Z factor treatment. The Board is of the view that a more suitable approach is to consider extraordinary event and transition costs on a case-by-case basis as proposed in the draft Rate Handbook.

4.4.8 The Board has not been persuaded that a separate and distinct process is required to address matters pertaining to the accounting, audit, or disposition of Z factor accounts (deferral accounts). Z factor applications will form part of the overall application and review of each distribution utility's rate adjustment. The Board of course has the authority to audit the accounts and accounting practices of the utilities at any time.

4.4.9 As for the suggestion that expenditures related to DSM activities be considered a Z factor, in light of the Board's findings in Chapter 6 on matters dealing with DSM generally, the Board has determined that it is premature to make a specific finding at this time.

4.5 INTER-CLASS RATE FLEXIBILITY

4.5.1 The draft Rate Handbook proposes that:

> *...a utility could structure a price cap mechanism separately for baskets of residential, general service and large use customers subject to the following constraints:*
>
> > *The results of the three price cap adjustments to the baskets do not produce an overall cap which exceeds the ceiling imposed on the utility's average price.*
> >
> > *None of the caps on individual baskets falls outside of a 5% flexibility adjustment zone.*

4.5.2 Board staff noted in their opening statement at the technical conference that the flexibility was intended to allow distribution utilities to adjust rates towards their own cost allocation circumstances over the term of the first generation PBR plan and to deal with threats of bypass by large customers.

4.5.3 Some parties expressed concern that the rate flexibility could be used for inappropriate inter-class subsidization, shifting revenue responsibility to captive customers, such as the residential class, from users that may have competitive options.

Board Findings

4.5.4 The Board notes that, during the proceeding, there was some confusion on how Board staff's pricing flexibility proposal was interpreted. To the extent that the five percent flexibility adjustment was intended to apply to the absolute price level, the Board finds merit in parties' arguments that there is a possibility of undue subsidy among customer classes. To the extent that the five percent flexibility adjustment was intended to apply only to the price cap adjustment, not the price itself, the Board questions the value of the scope of the flexibility. Further, it is not clear to the Board as to how average prices would be determined at any point in time. For all of the above reasons, and consistent with the Board's general approach not to unduly complicate the introduction of PBR, the Board does not adopt the pricing flexibility and baskets provision [section 4.5.1] in the draft Rate Handbook.

4.5.5 The Board however accepts that a utility may wish to confirm the reasonableness of class rates relative to cost causality. In proposing realignment of rates to better align rates with costs, the Board expects the utility to file an appropriate cost allocation study.

SERVICE QUALITY

5.

5.1.1 The draft Rate Handbook proposes that all distribution utilities measure six customer service indicators and three service reliability indicators for first generation PBR. A minimum level of service performance is proposed for each of the customer service indicators. For the distribution utilities that have at least three years data on a service reliability index, the distribution utility is expected to, at minimum, remain within the range of its historic performance. The draft Rate Handbook proposes that six of the nine indicators be reported to the Board, while the remaining three service quality measures need not be reported, but should be used by distribution utilities as standards for minimum guidelines in adopting management policy.

5.1.2 The following table outlines the service quality and reliability indicators proposed in the draft Rate Handbook:

Customer Service	Service Quality
Indicators Requiring Reporting: Connection of New Services Underground Cable Locates Appointments Indicators not Requiring Reporting: Telephone Accessibility Written Response to Inquiries Emergency Response	Indicators Requiring Reporting: System Average Interruption Index (SAIDI) System Average Interruption Frequency Index (SAIFI) Customer Average Interruption Duration Index (CAIDI)

5.1.3 The draft Rate Handbook also proposes that distribution utilities report performance results annually to the Board. Utilities would also be required to file remedial action reports in cases of substandard performance. The proposal anticipates that economic consequences for service degradations may be in place for second generation PBR.

Positions of the Parties

5.1.4 Some parties noted that service quality was historically dealt with locally (by the municipal government or Commission) and suggested that centralized service quality regulation is unnecessary. Other parties commented that service quality might be reduced as firms seek to reduce costs in pursuit of efficiency gains, and therefore regulation of service quality is appropriate. Section 1(3) of the Act was highlighted. This section states that one objective to guide the Board in carrying out its responsibilities is that it must act to protect the interests of consumers with respect to prices and the reliability and quality of electricity service.

5.1.5 Many parties commented that the proposals lacked detail and sought clarification to the definitions of indicators and standards. Others suggested that the indicators should measure only incidents that are directly controllable by the distribution utility and exclude failures in generation or transmission and *force majeure* incidents. CAC and Sault Ste. Marie Hydro submitted that the proposal for remedial action plans lacked specificity.

5.1.6 Some parties suggested that the proposed service quality indicators were inappropriate. For example, Upper Canada commented that indicators such as cable locates form an insignificant part of the distribution utility's operations. Others commented that while the indicators were appropriate, they were inadequate for allowing the Board to monitor the service performance of distribution utilities. Enbridge Consumers suggested that the number of service quality indicators was burdensome and should be reduced.

5.1.7 VECC and PWU suggested that data on momentary outages, in the form of an indicator called Momentary Average Interruption Frequency Index ("MAIFI"), be collected and reported.

5.1.8 FOCA and PWU suggested that aspects of public and employee health and safety should be reported as indications of performance while others held that employee safety was a responsibility of the organization and does not need to be reported.

5.1.9 GEC, Pollution Probe, and FOCA advocated that environmental performance be included in service quality monitoring. FOCA suggested that PCB handling could be one such environmental indicator.

5.1.10 Several parties (VECC, PWU, CAC) expressed concern about the effectiveness of service quality standards in the absence of economic penalties for non-compliance. PWU also suggested that financial penalties be imposed for non-compliance with data collection and reporting.

5.1.11 VECC suggested that earnings in excess of the market-based rate of return be tied to quality standards, similar to schemes in British Columbia and Quebec. However, they acknowledged that data may be a problem in the short term.

5.1.12 CAC and PWU suggested that all indicators should be reported and subject to some form of audit or review.

5.1.13 VECC and CAC suggested that performance results reported by the distribution utilities to the Board be made publicly available. It was also suggested that public reporting could motivate improvement of service quality.

5.1.14 Some parties commented that the introduction of systems to measure and report on service quality is a cost and burden on utilities not already doing so. It was also suggested that costs related to the introduction of service quality measurement systems should be allowable transition costs.

Board Findings

5.1.15 One of the objectives of the Act is protection of the consumers' interests with respect to prices, quality and reliability of electricity service. Any reduction in the quality and/or reliability of a service represents a reduction in the value of that service. Therefore, as part of its function in regard to approving or fixing just and reasonable rates, the Board has a responsibility to oversee that service quality is preserved and improved.

5.1.16 The Board recognizes that electricity industry restructuring introduces many unknown factors that could impact on performance levels and customer expectations. Further, there is a lack of consistent information on historical performance. Therefore, the Board is of the view that, for first generation PBR, a cautious approach to introducing service quality performance indicators and standards is warranted. The proposed approach in first generation PBR appropriately focuses on data collection, reporting, and monitoring of service quality and reliability performance by all distribution utilities.

5.1.17 The Board notes that the Board staff proposals for service quality indicators and standards were developed through the task force process which benefitted from input from the industry and other stakeholders and from a survey conducted by the task force itself. Although the task force found inconsistency in the measurement of service quality performance in the industry, nevertheless its surveys indicated that the proposed service quality and reliability measures are applicable to utilities of varying sizes and with varying operational characteristics (size, density, urban/rural, etc.).

5.1.18 The Board finds that the service quality indicators proposed in the draft Rate Handbook are appropriate for indications on the service performance of the distribution utilities over the course of first generation PBR.

5.1.19 The Board notes parties' comments seeking clarification of the definitions. To the extent that this is possible and practical, the Board will do so in the Rate Handbook.

5.1.20 The Board notes that, generally, parties representing electricity distribution utilities indicated that the proposed minimum standards are appropriate and achievable.[10] As a result, the Board favours the minimum standards proposed in the draft Rate Handbook for first generation PBR. The Board notes that these standards represent the minimum acceptable performance; a utility should continue to establish its operating performance at any level better than the minimum standard, taking into consideration the needs and expectations of its customers and of cost implications.

5.1.21 The Board considers that service interruptions as experienced by customers, regardless of cause, should be reported to the Board. The Board notes that the cause of service interruption is to be documented as well. In any instances of service interruptions, the Board will take into account exogenous factors that impact on the reported performance.

5.1.22 In contrast to the proposal in the draft Rate Handbook, the Board is of the view that all of the nine proposed indicators should be reported. The Board and the industry require the information that the reporting process will provide, in order to assess the adequacy of service delivered to customers, and in order to determine needed adjustments in second generation PBR. Accordingly, electricity distribution utilities are expected to measure and report to the Board their performance with respect to these indicators, in accordance with filing requirements described in the draft Rate Handbook.

[10] Board staff, under questioning during the Technical Conference, corrected the proposed standard for Connection of New Services (< 750 Volts) from 100% to 90%.

5.1.23 The Board sees merit in the suggestion that a measure of system reliability for shorter duration or momentary outages (MAIFI) be monitored and reported. However, the Board was not provided with sufficient information on the current use of MAIFI within the Ontario distribution electricity industry. The Board expects that this measure will be further investigated and considered in the review for second generation PBR.

5.1.24 With respect to suggestions that the list of reported indicators should be augmented to include measures of employee and public health, safety, and of environmental performance, the Board notes that utilities are accountable to other government institutions with respect to their performance in these areas. The Board has not been persuaded to add these measures.

5.1.25 The Board agrees with suggestions that service quality performance results of the distribution utilities should be reported to inform customers and the general public. The specifics regarding dissemination of such information will be addressed in due course.

5.1.26 The draft Rate Handbook proposes that service quality results be reported annually; there is no commentary about the periodicity of the results to be recorded (annual, quarterly, or monthly). Furthermore, there was no discussion by parties with respect to this issue. The Board has some concern that an annual average result may not provide it with adequate information on service degradation. Annual results can conceal seasonal variations in performance. Also, reporting only on an annual basis could result in a significant lag in identification of a service issue. The Board therefore will require utilities to record service performance on a monthly basis and for the first year to report the results to the Board at the time of the utilities' filings for year two of the PBR plan. The Board will review these results to determine whether more frequent reporting will be required. Further information is required to establish the appropriate criteria for determining that degradation has occurred; for example, degradation could be deemed to have occurred if the utility failed to meet the minimum prescribed standard for a certain number of months in a year. Such information should be available at the time of the filing for the second year of the PBR plan.

5.1.27 The Board has also considered the suggestions by parties that the PBR plan include remedial action and financial consequences in the case of service quality degradation. In the Board's view an appropriate assessment of these matters cannot be made until the Board and the industry have gained experience with the application of the PBR plan for the first year and appropriate service quality performance data becomes available.

DEMAND SIDE MANAGEMENT

6.

6.1.1 The draft Rate Handbook made no reference to Demand Side Management (DSM). In their opening remarks at the technical conference, Board staff stated as follows:

> *The current electric industry is in a state of flux. Many of the distribution utilities have stated the intent to enter the competitive energy retailing business. Such mixtures of competitive retailing businesses, even when separated through an affiliate code and subsidized DSM services delivered through a monopoly distribution business, raise substantial issues over potentially unfair advantage, illegal tying arrangements, discriminatory access to monopoly services and fairness in retailing.*
>
> *These issues of monopoly provided DSM programs for the benefit of unregulated entities have arisen in other jurisdictions, notably Norway and New Zealand.*
>
> *Further, the issue of the role of the distribution sector, particularly when many of the players are of such small scale in delivery of DSM services, has not been examined by the Board. For these reasons, the issue of DSM is considered to be beyond the scope of the first generation PBR process.*

Positions of the Parties

6.1.2 Pollution Probe and GEC reminded the Board that one of its responsibilities under the Act is "To facilitate energy efficiency and the use of cleaner, more environmentally benign energy sources in a manner consistent with the policies of the Government of Ontario." They argued that inclusion of DSM in the Rate Handbook, on either a mandatory or voluntary basis, would be consistent with the objectives of the Act. They pointed out that Board staff's proposals for a price cap mechanism act against DSM and that price caps are more adverse to DSM than are some other forms of PBR, such as revenue caps. Pollution Probe and GEC suggested that the same regulatory mechanisms that currently apply to the natural gas utilities should also apply to the electrical distribution utilities. At a minimum it was suggested that such approaches be voluntary, but that the Board should encourage utilities to undertake DSM programs. In addition, Pollution Probe and GEC submitted that DSM should be further considered for second generation PBR. In this regard, they suggested that a stakeholder forum or some other regulatory process be established to consider energy efficiency initiatives as part of second generation PBR.

6.1.3 FOCA suggested that utilities be required to report to the Board on DSM programs that they are currently engaged in. At a minimum, the Board should make a statement on the acceptability of distribution utilities initiating or continuing with DSM programs. Upper Canada suggested that the utilities that have already implemented DSM programs should be given the benefit of carrying on with such programs through the transition period.

6.1.4 Other parties acknowledged that the current restructuring of the industry creates confusion of the appropriate role of the distribution utilities with regard to DSM.

Board Findings

6.1.5 The Board acknowledges that facilitation of energy efficiency is one of the objectives of the Act and the Board acknowledges the importance of DSM in achieving such objective. However, there are a number of other objectives stated in the same Act. The Board's role is to find an acceptable balance among those objectives, especially when there is an appearance of competing ends. The Board notes Board staff's statement that the role of the electricity distribution industry with regard to DSM has not been examined as yet. Further, the Board notes that Board staff are currently in the process of consulting toward the development of guidelines with regard to section 71 of the Act. This section addresses the business activities in which electricity distribution utilities may engage.

6.1.6 Furthermore, substantive issues may arise from the monopoly "wires only" entity's involvement with DSM programs, and its relationship to the unregulated electricity sector's business. Also, the question of how DSM will be delivered in the restructured electricity industry requires better understanding.

6.1.7 In light of the above, it is the Board's view that a better understanding of all the issues surrounding DSM is needed before DSM principles, programs and mechanisms can be incorporated into a PBR regime for the electricity distribution industry.

6.1.8 The Board notes that parties indicated that some distribution utilities currently have active DSM programs. The Board encourages those distribution utilities to continue to offer these programs until such time as the guidelines regarding the appropriate business activities of the utilities and the role of DSM are established.

6.1.9 Further, the Board finds that, subject to the business activities guidelines and role of DSM issues discussed above, distribution utilities that wish to introduce DSM programs for first generation PBR can do so as long as the costs of these programs fit within the price caps.

6.1.10 The Board expects Board staff to include the appropriate considerations of DSM as part of the review for second generation PBR. The Board will include this conclusion in the Rate Handbook.

7. COMPLETION OF THE PROCEEDING AND COSTS

Implementation

7.1.1 Chapter 7 of the draft Rate Handbook deals with the sequence of events leading to the rate approval process, the process for annual rate adjustments for years two and three of the PBR plan, and for the development of a second generation PBR plan.

7.1.2 The draft Rate Handbook stipulated October 1, 2000 as the target date for the new unbundled rates to coincide with the date for market opening. The period from January 1, 2000 to October 1, 2000 would be utilized to complete the filing and approval process for the new rates. The draft Rate Handbook used May 1, 2000 as the final date for filing evidence for utilities with more than 30,000 customers, and August 1, 2000 for utilities with less than 30,000 customers.

7.1.3 This Decision does not alter the requirement for unbundled rates to be in place no later than market opening, currently anticipated to be in November 2000. Although the Rate Handbook is not yet available, with the issuance of this Decision utilities will be able to commence their preparation for filing their evidence with the Board. The Rate Handbook will be available as soon as practical. In the meantime, Board staff will continue to develop the unbundling and rate design model and will make the model available as soon as it has been adequately tested.

Costs

7.1.4 During the proceeding various parties requested an award of costs. The Board has received some cost statements from certain parties. At least one party suggested that no costs should be awarded for this proceeding. The Board would be assisted by submissions from parties regarding the awarding of costs in this proceeding. Submissions may address whether costs should be awarded in this proceeding and, if so, to whom they should be awarded and from whom they should be recovered. Parties are requested to file any submissions in this regard no later than February 15, 2000. Parties claiming costs should also file cost statements by this date.

DATED at Toronto January 18, 2000.

George Dominy
Vice Chair and Presiding Member

Paul Vlahos
Member

Sally Zerker
Member