RP-2000-0069

IN THE MATTER OF a proceeding under sections 129(7) and 78 of the *Ontario Energy Board Act, 1998* S.O. 1998, c.15, Sched. B to determine certain matters relating to the Minister's Directive dated June 7, 2000.

BEFORE: Paul Vlahos
Vice Chair and Presiding Member

George Dominy
Vice Chair and Member

Sheila Halladay
Member

Sally Zerker
Member

DECISION WITH REASONS

September 29, 2000

TABLE OF CONTENTS

1. BACKGROUND

1.0.1 In November 1998, the *Energy Competition Act, 1998* (or Bill 35) received royal assent. This legislation gives the Ontario Energy Board ("Board" or "OEB") the authority to set the rates for electricity distribution utilities in the Province of Ontario.

1.0.2 In anticipation of the passage of Bill 35, the Board stated its intent to implement new approaches to regulation, including the use of Performance Based Regulation ("PBR"), wherever appropriate.

1.0.3 Starting in October 1998, a series of documents, consultations, task forces, and educational seminars culminated in Board Staff issuing a proposed rate handbook, which outlined the policies, guidelines and procedures to be used in the establishment and adjustment of electricity distribution rates for a first generation PBR plan. These were reviewed in a generic proceeding which commenced in August 1999. The Board's Decision (RP-1999-0034) was issued in January 2000.

1.0.4 These initiatives, activities and decisions led to the Board issuing the Electricity Distribution Rate Handbook (the "Rate Handbook") in March 2000. Pursuant to the Rate Handbook, and the Rate Unbundling and Design Model ("RUD model") constructed by Board staff, 24 large utilities filed applications for new rates in May 2000. These applications included requests for revenue requirement increases to provide the utilities with the opportunity to earn market based returns and, after market opening, for payments in lieu of taxes ("PILs"). Utilities requested revenue requirement increases which ranged from 5.3% to 12.1%, averaging 8.5%. Notices of these applications, including the total bill impact on residential customers, were published in local newspapers.

1.0.5 On June 7, 2000 the Minister of Energy, Science and Technology ("Minister") issued a policy directive ("Directive") to the Board under section 27 of the *Ontario Energy Board Act, 1998* (the "Act"). The Minister's Directive is included as Appendix 1. The first paragraph of the Directive reads as follows:

> In making an order under section 78 of the Act approving or fixing just and reasonable rates for the distributing of electricity by a municipal electric utility, in being guided by the objectives set out in section 1 of the Act, the Board shall give primacy to the objective "to protect the interests of consumers with respect to prices and the reliability and quality of electricity service".

1.0.6 The Directive also required the Board to invite representations from the councils of the municipal corporations within the distributors service area before setting rates for the distributing of electricity by a municipal electric utility.

1.0.7 On June 8, 2000, in a letter to the Chair of the Board, the Minister asked the Board to provide him with a plan outlining how the Board would implement the Directive, prior to making any rate decisions.

1.0.8 On June 19, 2000, the Board provided the Minister with a plan which included holding a generic proceeding to address the implications of the Directive on the Rate Handbook. The present proceeding and this Decision are in response to the plan proposed to the Minister.

1.0.9 On June 20, 2000, the *Ontario Energy Board Amendment Act, 2000* (or Bill 100) was introduced. Bill 100 received First Reading before the Legislative Assembly rose for summer recess. Bill 100, if enacted, would impose certain restrictions on rate increases attributable to a utility's financial arrangements, or to cash and other assets retained by the municipality upon the transfer of assets from the utility to the municipality.

1.0.10 On June 26, 2000, the Board advised interested parties that, in light of the generic hearing, it would be suspending the review of the previously-filed rate applications, and delaying the requirement for filing rate applications by the remaining distribution utilities.

1.0.11 On July 7, 2000, the Board communicated to stakeholders the issues for this generic proceeding, which are set out below:

1. The rate impacts resulting from the elements in the determination of a market-adjusted revenue requirement ("MARR").

2. The entitlement of utilities to recover deferred return and, if so, methods of recovery.

3. The entitlement of utilities to recover utility business re-engineering costs and, if so, methods of recovery.

4. Filing requirements that give indications of how rate impact mitigation might affect service reliability and quality, and what these filings might consist of.

5. The level of 10% within class rate impact guideline related to rate restructuring included in the Rate Handbook.

1.0.12 In its covering letter the Board noted that, while Bill 100 is not an issue in this proceeding, in making their submissions parties may wish to consider Bill 100 as it relates to the issues.

1.0.13 Interested parties were requested to file written submissions by July 27, 2000. The Board received 40 written submissions.

1.0.14 From August 9 through August 16, 2000, twenty-four parties made oral presentations and responded to questions from Board Staff and the Board Panel.

1.0.15 Parties were provided with the option of making reply submissions on or before August 25, 2000. The Board received 15 reply submissions.

1.0.16 A list of the parties who participated through written or oral submissions is appended to this Decision as Appendix 2. Copies of all the submissions and the verbatim transcript of the hearing are available for review at the Board's offices. While the Board has considered all the submissions, the Board summarized them only to the extent necessary to clarify its findings.

1.0.17 The remaining part of this Decision is structured as follows: Chapter 2 deals with the status and interpretation of the Minister's Directive. Chapter 3 deals with the implementation of the Directive. Chapter 4 deals with other issues raised. Chapter 5 deals with rate implementation matters and cost awards.

2. STATUS AND INTERPRETATION OF THE MINISTER'S DIRECTIVE

2.0.1 The Directive was issued under subsection 27(1) of the Act which states the following:

> The Minister may issue, and the Board shall implement, policy directives that have been approved by the Lieutenant Governor in Council concerning general policy and the objectives to be pursued by the Board.

2.0.2 A number of legal concerns were raised with respect to whether the Directive exceeded the Minister's statutory authority.

2.0.3 It was argued that the Directive is quasi-legislation which fetters the Board's discretion and is therefore not authorized by section 27 of the Act. In the Board's view, the Minister clearly has authority to issue a policy directive which limits the Board's discretion. This limitation on the Board's discretion is not analogous to the traditional administrative law principle which prohibits a tribunal from fettering its own discretion.

2.0.4 It was further submitted that the Directive goes beyond policy making and inappropriately amends the legislation as it sets out rules of conduct. Since all subordinate statutory instruments, such as regulations and policy directives, contain rules of conduct, the real issue is whether the subordinate legislation has been authorized by the governing statute. In this case, section 27 of the Act makes express reference to policy directives concerning “the objectives to be pursued by the Board”. Therefore, the Board determines that the Minister acted within his authority in issuing the first paragraph of the Directive.

2.0.5 Another legal argument was made that the second paragraph of the Directive, which requires the Board to invite representations from municipal councils before setting rates, exceeds the Minister’s authority as it addresses a procedural matter rather than a substantive policy matter. The Board is of the view that, in the unique circumstances of the transformation of the municipal electric utilities into commercial entities, it is appropriate for the Board to invite representations from municipal councils. Therefore, the Board does not need to make a finding on whether this portion of the Directive is within the Minister’s authority.

2.0.6 One party took the position that the Board should have permitted the introduction of evidence and cross examination in this proceeding. The Board finds that the process followed by the Board of written submissions, the opportunity to make oral presentations, and the right to reply is sufficient to address the issues that arose from the Directive in this proceeding.

2.0.7 The Act sets out the following six objectives that shall guide the Board in carrying out its responsibilities with regard to electricity matters:

1. To facilitate competition in the generation and sale of electricity and to facilitate a smooth transition to competition.

2. To provide generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario.

3. To protect the interests of consumers with respect to prices and the reliability and quality of electricity service.

4. To promote economic efficiency in the generation, transmission and distribution of electricity.

5. To facilitate the maintenance of a financially viable electricity industry.

6. 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.

2.0.8 The Directive requires the Board to give primacy to the third objective, “to protect the interests of consumers with respect to prices and the reliability and quality of electricity service”.

2.0.9 One party argued that the statement in the Minister’s Directive, that the objective set out in paragraph 3 of section 1 of the Act should be given “primacy”, is not to be interpreted to mean that this objective should be given “paramountcy” over the other objectives. Rather, the word “primacy” must be interpreted to merely mean that this objective would be considered before the other objectives. It was further argued that one of the objectives could not be given “paramountcy” over the other objectives without a legislative amendment.

2.0.10 Parties noted that the third objective cannot stand in isolation. They pointed out that the legislation did not prioritize these objectives. Instead, they argued, there needs to be a balance of this objective with the remaining five objectives since they have direct and indirect impacts on consumer protection.

2.0.11 It was pointed out, for example, that the protection of the consumer interests objective is directly related to the maintenance of a financially viable electricity industry, i.e., objective 5. In a commercial regime, the financial viability of a utility is integral to the protection of consumer interests.

2.0.12 Parties reminded the Board that in considering these objectives the Board must also be mindful of its obligation under section 78 of the Act to set rates which are just and reasonable. Most parties submitted that the Rate Handbook strikes a reasonable balance among the objectives.

2.0.13 Parties expressed concerns that Bill 100 and the Directive have raised serious doubts about the autonomy of the Board. It was specifically noted by one party that "one of the worst losses that we may sustain is the loss of independent regulation and the legitimacy and the honour of the Ontario Energy Board".

2.0.14 A wide range of views emerged with respect to the meaning and implications of the Directive, and also with regard to possible measures for implementation. All parties appeared to link the Directive with rate impact concerns arising from the introduction of market returns.

2.0.15 Parties'suggestions for responding to the Directive ranged from imposing a moratorium on distribution rate increases to allowing the rate increases necessary for the commercial orientation of the utilities without any rate smoothing.

2.0.16 Many parties expressed the view that the ratemaking provisions and the policies contained in the current Rate Handbook, perhaps with more concrete mitigation measures, are responsive to the Directive and therefore the Directive is redundant and Bill 100 is unnecessary.

2.0.17 Other parties questioned whether the Directive, in conjunction with Bill 100, is a retraction of the commercial direction set out in the White Paper and in the provisions of Bill 35 for municipally-owned utilities, and essentially a reversion to a power-at-cost regime. In this connection, one party proposed that the Board be given the authority to undertake a review of electricity market restructuring, and to impose rate caps in the interim. Another party suggested that the Board should seek clarification from the Government as to its intentions; otherwise the Board would not be able to respond adequately to the Directive.

2.0.18 The Board takes note of the suggestion that clarification of the Directive should be obtained from the Government. The Board does not believe that further clarification is warranted. To do so would prolong the regulatory uncertainty for all stakeholders.

2.0.19 The Board does not interpret the Directive as a move away from the commercial orientation of municipally-owned utilities as set out in the White Paper and in the legislation. The Board does not view the Minister's Directive to mean that there should be no return on capital. Nor does the Board believe that the Directive instructs the Board to set rates that are not just and reasonable, and thus impair its role as a regulator.

2.0.20 On the contrary, the Board is of the view that in the new commercial setting, the best way to protect consumers with respect to prices, and the reliability and quality of service, is to facilitate the establishment and maintenance of a financially viable electricity distribution sector. It is fundamental for a viable electricity distribution sector in a commercial setting to have opportunities for earning a market rate of return.

2.0.21 The Board therefore interprets the Directive as reflecting the Government's concern about rate impacts associated with the provision of market returns embodied in the corporatization and commercialization of the electricity distribution utilities. In particular, the Board interprets the Directive as requiring the Board to apply its regulatory powers and use its discretion to seek solutions that recognize the uniqueness of moving Ontario's electricity distribution sector to commercialization. In that regard, the Board interprets the Directive as a reminder that, during the transition period, consumer interests must come before maximization of returns.

3. IMPLEMENTATION OF THE DIRECTIVE

3.1 RATE IMPACT OF MARKET ADJUSTED REVENUE REQUIREMENT

3.1.1 The current Rate Handbook deals with provisions for initiating new market based rates and for rate adjustments for the first three-year PBR term. The Rate Handbook permits a utility to elect a market based return upon initiation of new unbundled rates. In view of Board concerns about the potential substantial impact on rates arising from a decision to move toward a full market based return, the Board provided the utilities with the mechanism of deferral accounts to smooth the rate impacts and to recover deferred amounts over future years, but left choices on these issues at the local level. Subject to rate impact considerations, recovery of the deferred amounts may commence as soon as the following year. The Board cautioned that if the utilities did not take adequate steps toward rate impact-smoothing, the Board would either seek revised proposals or fix the rates itself.

3.1.2 The Rate Handbook stipulates a 50:50 sharing between the utility and its customers of excess profits which may arise from better revenue performance and/or from efficiencies above those reflected in the PBR formula.

3.1.3 This generic hearing elicited a general concurrence among utilities and municipalities with respect to rate mitigation. Most suggested rate impact smoothing techniques which would phase-in market returns over a number of years, but allow utilities to make the full return on capital permitted in the Rate Handbook by recovering the deferred revenue in the future. There were, however, variations on this theme.

3.1.4 Most suggested a phase-in period of three years to coincide with the first generation PBR regime. Some, however, indicated that the phase-in period could be extended. A skewed, rather than even phase-in, was recommended under specific circumstances.

3.1.5 Some suggested that deferred returns would be drawn down only through efficiency gains over and above the productivity factor stipulated in the PBR formula. Others suggested a draw down of the deferral account resulting from efficiency gains, but recovery of any remaining balances in the deferral accounts by the use of a Z factor. In almost all cases, the draw down would utilize 100% of the excess efficiencies rather than the 50:50 sharing mechanism stipulated in the current Rate Handbook.

3.1.6 Some suggested that the recovery of the deferred amounts could commence during the first generation PBR term, while others suggested that recovery be delayed to after the phase-in period. A phase-in without recovery of deferred amounts was also suggested.

3.1.7 A phase-in mechanism was generally supported by parties beyond utilities and municipalities, with some exceptions. Energy Probe suggested implementing the full rate increase immediately, arguing that the use of a phase-in mechanism and deferrals distort market signals and conceals future rate increases. In making this suggestion, Energy Probe noted to the Board its recommendation to the Government that it impose a "windfall tax" on the earnings of the electricity distribution utilities. Also, one party suggested a graduated revenue rebate to customers as a way of phasing-in market returns.

3.1.8 Several parties argued that, given the capital intensive nature of the electricity distribution industry, and thus the small share of variable costs which are amenable to efficiency gains, it would not be possible to achieve market returns through efficiencies alone. For example, it was pointed out that Mississauga Hydro would have to reduce operating costs by 97% and Toronto Hydro by 60% in order to reach that goal.

3.1.9 In the Board's view, a phase-in approach for achieving market returns is consistent with the Board's interpretation of the Directive. The mechanism to be employed to achieve such phase-in is discussed below. The critical issue is whether utilities should be entitled to any deferred return. To address this issue, it is worthwhile repeating relevant factors inherent in the restructuring process.

3.1.10 The ownership issue for Ontario's electricity distribution assets has now been clarified in the legislation. The municipality now owns these assets and assumes any associated liabilities. As owners, municipalities would expect opportunities to earn a reasonable rate of return on those assets.

3.1.11 Reasonable return is generally accepted to mean sufficient earnings for the utility to perform its tasks and to provide a fair return to its owner. Case law supports the principle that just and reasonable rates for an enterprise operating in a commercial setting generally entitles the owner of a utility to be given an opportunity to earn a fair return. There are also economic and regulatory principles that dictate that a commercial utility's viability cannot be sustained unless there is an opportunity for market returns. But in the context of Ontario's current electricity distribution industry situation and the issuance of the Directive, the right to deferred returns cannot be viewed as unrestricted.

3.1.12 The history and transitional nature of the electricity distribution industry in Ontario is exceptional, and therefore it is questionable whether the entitlement to unrestricted returns by the municipal owners ought to be recognized immediately in light of the Directive. The ownership of the electricity assets and liabilities was not clarified until Bill 35 came into effect. Municipalities cannot be said to have "invested" capital, in the usual sense of the word, although they became "owners" of previously-invested capital consequent to the passage of the Bill. On the one hand, therefore, there is a distinct difference for the investor of capital in such an enterprise from that where the investment has an *a priori* expectation of a reasonable return. On the other hand, in a commercial setting, a utility's revenue requirement must reflect some cost of capital to be financially viable. Given the Board's interpretation of the Directive and the specific circumstances in Ontario, the Board finds that it may be necessary to deny recovery of those amounts which are not reflected in the rates allowed during the transition period.

3.1.13 In the long run, the utility's viability and consumer protection will depend on the utility's ability to capitalize on opportunities for market returns afforded by the applicable regulatory framework.

3.1.14 The Board notes the suggestion by many parties that a phase-in mechanism should be accompanied with the suspension of the sharing mechanism for any excess earnings. On the basis of the record, the suspension of the sharing provision may not entirely – or even in large part – offset the lower returns from phasing-in market returns. However, the suspension of the excess earnings sharing feature provides an opportunity to a utility to improve its earnings, and it would also remove an area of uncertainty as to the precise interaction of sharing, returns, and deferred returns.

3.1.15 Much concern was heard about the utilities' difficulties if they were not given the opportunity to earn market returns. Such concerns included:

- value degradation of a utility's assets
- denial of a level playing field with gas distribution utilities, Hydro One, and private electricity distributors
- discouraging mergers, amalgamations, acquisitions and divestitures ("MAADs")
- eroding investor confidence
- difficulty in raising capital

3.1.16 These impairments were noted as being contrary to the Government's objectives for restructuring the electricity industry as set out in the White Paper and Bill 35.

3.1.17 While the Board appreciates that these are legitimate concerns for utilities and their shareholders, in the Board's view these concerns arise not only from not achieving a market based return during the transition period, but also result from other uncertainties relating to restructuring. In any event, on the basis of the Board's interpretation of the Directive, the concerns that are linked to market returns must be given a secondary consideration to the primacy of the consumer protection objective in the transition period.

3.1.18 On balance, the Board finds that the intent of the Directive can be accomplished by adopting a smoothing mechanism where the market returns are phased-in over a period of time, without deferrals, and without a sharing mechanism for any excess earnings.

3.1.19 While some parties suggested that the phase-in period may exceed three years, many parties proposed a three-year phase-in period. The Board adopts a three-year phase-in process, timed to be consistent with the time frame of the first generation PBR plan. Except in the special circumstances, such as those noted below, the phasing-in of market returns shall be in equal dollar increments. There shall be no deferral of Market Adjusted Revenue Requirement [1] (or MARR) not included in rates.

3.1.20 If, for example, the total incremental revenue requirement is calculated at $6 million, an incremental $2 million amount shall be included in rates for each year over the three-year period. Therefore, in this example, the full $6 million incremental revenue requirement would be included in rates by the third year of the phase-in period.

3.1.21 A utility can choose to move to MARR or to some level below MARR. There shall be no deferral of MARR foregone. For example, if a utility is entitled to include in its rates an incremental amount of $2 million but chooses to include only $1.5 million, the utility will not be entitled to include the foregone $0.5 million amount in future rates.

3.1.22 A specific issue was raised at the hearing with respect to the calculation of MARR for those utilities that had negative returns in 1999. The Board confirms the provisions

1 MARR provides the total revenue requirement associated with the return on capital, debt, and payments in lieu of taxes.

in the current Rate Handbook that if a utility had a negative return in 1999, a floor value of 0% would be applied to the 1999 base returns in calculating the incremental revenue requirement.

3.2 SPECIAL CIRCUMSTANCES

3.2.1 This hearing provided the utilities another opportunity to bring out issues arising from the diversity that characterizes Ontario's two hundred plus electricity distribution utilities, and ways in which the Board can reflect this circumstance in its deliberations and decisions. The message was reiterated that "one size may not fit all", particularly in respect of the unique financial circumstances that may apply to specific utilities with a phase-in of market returns.

3.2.2 The Board has attempted to recognize these concerns in its past decisions and to come up with solutions that are both practical and fair. The Board recognizes that there may be circumstances where the MARR phasing-in may result in financial distress for a utility. In the context of the phase-in period, financial distress generally does not mean below market returns, lower returns compared to other utilities, or loss of revenue due to restructuring, or from anticipated adverse business conditions. Financial distress generally means the inability to meet financial obligations incurred prudently. Should a utility perceive that it is in genuine financial distress, it has the opportunity at any time to make its case before the Board.

3.2.3 Should a utility claim special circumstances and seek a skewed phase-in of market returns in conjunction with its application for the establishment of initial rates, the utility must recognize that there will likely be additional processes needed to deal with its application.

3.3 RE-ENGINEERING COSTS

3.3.1 The current Rate Handbook authorizes the utilities to record qualifying transition costs. These are 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. Recovery of the prudently incurred re-engineering costs is deferred until after the setting of initial rates.

3.3.2 The vast majority of the parties submitted that the utilities are entitled to recover these costs. Some advised an early recovery, others suggested a multi-year recovery to avoid undue rate impacts. Some proposed that the costs should be pre-defined and the recovery period be determined now. It was submitted by some that the Board authorize the utilities to also record carrying costs associated with the deferred amounts. There was general support for the criteria set out in the Rate Handbook for the Board to ascertain eligibility for recovery of the re-engineering costs.

3.3.3 The Board recognizes that re-engineering costs pose a pressure to a utility's cash flow. Having provided for a skewed phase-in of market returns for special financial circumstances, the Board will not also allow recovery of the re-engineering costs with the setting of initial rates. Re-engineering costs will likely continue to be incurred up to the time of market opening. The Board finds that the classification and recording of utility re-engineering costs shall continue in accordance with the current Rate Handbook. The initial rates shall therefore not reflect any of the re-engineering costs.

3.3.4 As soon as practical following market opening, the Board will initiate a review of the appropriate timing and mechanism toward the recovery of the re-engineering costs.

3.3.5 Further, the Board authorizes the recording of interest associated with the deferred amounts to be recovered. The rate of interest for each utility shall be the same as the rate of debt allowed for the utility in the Rate Handbook

3.4 FILING REQUIREMENTS FOR SERVICE RELIABILITY AND QUALITY

3.4.1 Pursuant to the current Rate Handbook, utilities are required to record service performance on a monthly basis for six customer service indicators and three service reliability indicators. For the first year, utilities are required to report the results to the Board at the time of the utilities' filings for year two of the PBR plan.

3.4.2 The Board requested parties' views on what additional filings should be required that would give indication on how rate impact mitigation might affect service reliability and quality.

3.4.3 Several parties suggested that filing requirements should be limited to instances where it is necessary to demonstrate how rate impact mitigation results in a revenue shortage that compromises service reliability and quality. Others suggested some form of filing that identifies activities that need to be deferred because of the rate impact mitigation measures. Others submitted that the current service quality filing requirements should be sufficient, with the expectation that MARR will be phased-in. There was, as well, a proposal that utilities be required to file cash flow statements, since a shortage of cash may result in compromise of service. There was also a suggestion that the Board monitor expenditure trends to determine whether reliability is being compromised. Finally, some parties suggested imposing penalties if minimum service quality indicators were not met.

3.4.4 The Board notes that some of the suggestions, particularly the suggestion for imposition of penalties, were issues raised in the RP-1999-0034 generic proceeding which led to the finalization of the Rate Handbook. Given the Board's findings in that proceeding, and the Board's conclusions in this proceeding, no changes are necessary to the filing provisions currently contained in the Rate Handbook.

3.5 RATE RESTRUCTURING

3.5.1 The need to unbundle the delivered cost of power from the cost of distribution, as required for market opening, leads to certain rate restructuring. The rate restructuring stipulated in the Rate Handbook accomplishes the unbundling as well as introducing a two-part rate (a customer service charge and a variable charge) for delivery service. Some utilities have already incorporated a two-part rate structure. While there is no revenue requirement pressure for a utility in moving to the new rate structure, the two-part rate leads to a reallocation of revenue requirement responsibility by customers within a rate class. The current Rate Handbook provides a guideline of a maximum increase of 10% on the total bill for low use customers within a rate class.

3.5.2 The Board sought the views of parties with regard to the level of 10% rate impact guideline within a class.

3.5.3 There was general support for limiting the rate impact on customers from rate restructuring and for the 10% guideline. A general concern by the utilities about the guideline was that the revenue risk for a utility increases as the variable component of the rate structure increases. Suggestions included employing a fixed charge for distribution service for each class, and establishing a maximum quantum increase. Some parties suggested there is a need for a common definition of a small volume customer to ensure province-wide consistency, while others argued that this would restrict flexibility and the ability to recognize local conditions.

3.5.4 While the Board recognizes that uniformity is desirable, a common definition would introduce a level of rigidity that may not accord well with the needs of each utility to accommodate its own customer profile. However, the Board notes that the criteria used by the utility to determine a small volume customer may be reviewed as part of the utility's initial rates application.

3.5.5 The Board recognizes that the revenue risk for a utility increases as the proportion of the variable component of a rate structure increases. In the spirit of the Directive, for the transition period the Board will place less weight on a utility's revenue risk and more weight on customer impacts in establishing initial rates.

3.5.6 While the Board recognizes that there may be circumstances where a quantum measure of rate impact may be a relevant consideration, and the Board may be convinced in those circumstances to review requests for variation from the guideline, the Board has not been persuaded of the need to alter the 10% guideline.

3.5.7 Some parties brought to the Board's attention that a major rate impact may arise following the initial setting of rates for customers in the general service rate class who currently fall in the under 50 kW category for billing purposes and who may cross, even marginally, the 50 kW threshold. The Board acknowledges this potential difficulty. In this regard, the Board will initiate a review of the rate design for the general service class as soon as practical. For purposes of utility filings for establishing initial rates, and until such time as the Board addresses the cross-over issue in a separate process, the utility shall continue to bill these customers as if they were in the same under 50 kW category up to a demand level of 100 kW.

4. OTHER MATTERS

4.0.1 This chapter reports on certain issues raised by the parties that were not on the issues list.

4.1 PARTIES' COMMENTS ON BILL 100

4.1.1 Although the issues list for this proceeding did not specifically include consideration of Bill 100, the Board did add that "parties may wish to consider Bill 100 as it relates to the issues". Many parties used the hearing as an opportunity to express additional concerns with respect to the impact of Bill 100.

4.1.2 The Board does not have jurisdiction to deal with the concerns raised regarding Bill 100. However, in light of the preoccupation and strong concerns expressed by the parties in this proceeding, the Board has summarized the common themes that emerged from both written submissions and oral presentations. These include:

- Bill 100 is in direct conflict with the goals and principles of the White Paper and Bill 35, such as, the maintenance of a financially viable electricity industry, and the promotion of economic efficiency in the distribution of electricity.

- The Directive and Bill 100 is part of a single policy on the part of the Government to limit rate increases for consumers of electricity, without fully appreciating the harm to individual utilities and to the industry as a whole.

- Bill 100 is unfair because it "changes the rules in midstream".

- Even though Bill 100 has not been passed, it has upset and discouraged merger and acquisition plans for potential investors and sellers in the market.

- Bill 100 has made it difficult to estimate the value of the utilities and it is seen as discouraging investment, referred to by one intervenor as "investment chill".

4.1.3 The Board recognizes that the status of Bill 100 creates uncertainty for participants in the electricity market, but the Board anticipates that this uncertainty will be resolved in a timely manner.

4.2 PARTIES' COMMENTS ON STRIPPED EXCESS CASH

4.2.1 In the oral portion of this proceeding, the Board pursued the question of whether in setting rates it should take into account any cash which had been removed from a utility by its shareholder pursuant to a transfer by-law. Some parties in their reply submissions argued that to reduce rates because of the removal of cash from the utility would in effect be unraveling the lawful actions of the shareholder taken in accordance with Bill 35, and would exceed the Board's jurisdiction. These parties argued that such reduced rates would not be "just and reasonable" as they would not provide an appropriate return on the equity in the utility.

4.2.2 In considering this issue the Board notes that the Board has no jurisdiction to review a transfer by-law enacted pursuant to section 145 of the *Electricity Act, 1998*. The Board is of the view that it should be wary of second guessing the decisions of shareholders in structuring their utilities.

4.3 TAXPAYER AND ELECTRICITY RATEPAYER

4.3.1 Certain parties submitted that the Board's analysis and deliberations should consider the fact that in most cases the utility's customer is also a municipal taxpayer. Consequently, if utility rates do not increase, municipal taxes will.

4.3.2 While the Board understands the reasons for this position from a municipality's perspective, the Board emphasizes that its authority is limited to the consideration of the electricity distribution utility customers. Further, the interests of taxpayers and ratepayers are not necessarily identical.

4.4 COST OF POWER

4.4.1 Municipal utilities expressed concern that their requested rate increases were being compared unfavourably with Hydro One's decision to maintain its rates at current levels. They pointed out that the reason why Hydro One is able to do so, while still obtaining a commercialized revenue requirement, is because Hydro One's cost of power is a notional cost which resulted from transitional revenue reallocation among the successors of Ontario Hydro.

4.4.2 The municipalities contended that, if the rates charged by the municipal utilities reflected Hydro One's notional cost of power, the resulting reduction in the cost of power would more than offset the rate increases requested to enable utilities to move to market based returns. In fact, some municipal utilities even claimed that they could reduce rates.

4.4.3 The Board notes that Hydro One acknowledged that on market opening, assuming a cost of power of 6.2 cents per kWh and in the absence of any mitigation measures, its customers would face an average overall increase of 13% on their total bill.

4.5 CONTRIBUTED CAPITAL

4.5.1 The current Rate Handbook stipulates that capital that is contributed by customers on or after January 1, 2000 will not be included in a utility's rate base. Capital that was contributed prior to January 1, 2000 would be included in rate base and would earn the same return as all other capital.

4.5.2 One party suggested that the Board revisit its decision on the treatment of historically contributed capital because it believed that the Board's decision would have been different had the Directive been given prior to that decision. Another party stated that the allowance of return on historically contributed capital should be reversed. One party proposed that the decision on contributed capital should be phased-in or suspended until MARR is achieved.

4.5.3 The Board finds that the contributed capital issue has been adequately reviewed at the proceeding that culminated in the current Rate Handbook (RP-1999-0034). The Board has not been persuaded to alter its conclusions on the issue of contributed capital.

4.5.4 Several parties stated that changes in a utility's ability to access development charges, as well as uncertainty as to the timing of implementation of the capital contribution guidelines contained in the Distribution System Code ("DSC"), has caused difficulty with respect to system expansions. The DSC requires distributors to perform economic evaluations in order to determine whether capital contributions are necessary and defines the methodology and assumptions for such economic evaluations. However, the DSC is not expected to come into force until market opening.

4.5.5 In order to promote stability and consistency among distributors with respect to capital contribution charges, the Board finds that the provisions in the Distribution System Code that determine whether capital contributions should be collected and the methodology and assumptions for an economic evaluation are in force upon the issuance of this Decision.

4.6 DEMAND SIDE MANAGEMENT

4.6.1 The current Rate Handbook indicates that the role of the electricity distribution utilities with regard to Demand Side Management ("DSM") has yet to be examined. It was made clear in the Rate Handbook that delivery of DSM in the restructured electricity industry requires better understanding, and that appropriate considerations of DSM will be included in the review for second generation PBR. In the Rate Handbook, utilities are encouraged to continue existing DSM programs and to offer new programs if they can be established cost-effectively under the price caps.

4.6.2 Pollution Probe argued that DSM is a prerequisite for protection of customers since lowering demand will result in lower prices, necessitating that the Rate Handbook be revised accordingly.

4.6.3 The Board believes that Pollution Probe's suggested linkage of DSM to the Directive is a stretch. The Board has not been persuaded to alter its previous decisions on DSM matters.

5. IMPLEMENTATION OF NEW RATES AND COST AWARDS

5.1 IMPLEMENTATION OF NEW RATES

5.1.1 The current Rate Handbook will be amended to reflect the Board's conclusions as soon as practical. However, to expedite the implementation of the new rates, utilities can file or amend their filed applications without waiting for the issuance of the amended Rate Handbook.

5.1.2 All utilities must file or refile their rate applications for unbundled rates no later than November 30, 2000. The specific effective date for a utility will be determined based on the time required for publication of notices and Board review. The Board will do its best to ensure that the new rates are implemented as soon as practical.

5.1.3 The Board reminds utilities that in order to expedite the review, completeness of the applications, accuracy of its contents, as well as adherence to the guidelines are essential. The effective date for a utility's rates will be dependent on the complexity of the application's contents.

5.1.4 These new rates, if effective prior to proclamation of section 93 of the *Electricity Act*, shall not include PILs. The rates incorporating PILs will be reviewed when the date for proclamation of section 93 of the *Electricity Act* is known.

5.1.5 The revised Rate Handbook will also reflect revised dates for the calculation of the Input Price Index and for the formulaic rate adjustments for years 2 and 3 of the first generation PBR.

5.1.6 The Board notes that some concern was expressed on the use of utility specific 1999 cost of power in determining the rate impact of distribution rate increases on total bill amounts, since it may not reflect the cost of power that will be charged in the future when the market has opened. Some parties expressed a preference for basing rate impact notification on the distribution bill component only, rather than the total bill amount.

5.1.7 With regard to the cost of power that the electricity distribution utilities should use in unbundling rates, the Board reiterates that the use of the 1999 actual cost of power allocated to customer classes according to the Rate Handbook and built into the RUD model is appropriate.

5.1.8 With regard to rate impacts resulting from distribution revenue adjustments, the Board continues to be of the view that notification to customers should be based on the 1999 total bill amount. Customers are likely to be more familiar with their total bill rather than the distribution component alone, and can better relate to rate increases put in the context of these total bill amounts.

5.1.9 Parties commented that the RUD model does not deal with the reconciliation of the pre-market opening cost of power that may be required with the change in the market opening date, since utilities are billed for their power costs on the basis of time-of-use. If changes are required, the revised Rate Handbook will provide guidance in establishing an appropriate reconciliation mechanism.

5.2 COST AWARDS

5.2.1 Parties eligible for a cost award shall file their cost claims by November 1, 2000. The Board will issue its decision on cost awards in due course.

DATED AT Toronto September 29, 2000.

Paul Vlahos
Vice Chair and Presiding Member

George Dominy
Vice Chair and Member

Sheila Halladay
Member

Sally Zerker
Member