Ontario

QUESTIONS AND ANSWERS

SEMINARS ON

ONTARIO ENERGY BOARD

STAFF PROPOSED ELECTRIC

DISTRIBUTION RATE HANDBOOK

JULY 13-23, 1999

RESPONSES TO WRITTEN QUESTIONS OBTAINED AT SEMINARS ON THE ONTARIO ENERGY BOARD STAFF PROPOSED ELECTRIC DISTRIBUTION RATE HANDBOOK ARE PRESENTED HERE.

DURING THE SECOND HALF OF JULY 1999, THE ONTARIO ENERGY BOARD CONDUCTED A SERIES OF INFORMATION SESSIONS IN VARIOUS LOCATIONS TO INFORM INTERESTED PARTIES ON THE BOARD'S STAFF'S PROPOSAL FOR PERFORMANCE-BASED REGULATION (PBR) FOR ELECTRICIAL DISTRIBUTION UTILITIES. QUESTIONS WERE RECEIVED FROM PARTICIPANTS, AND ANSWERED WHERE POSSIBLE AT THE SESSIONS. THE FOLLOWING IS AN EDITED VERSION OF QUESTIONS AND ANSWERED ORGANIZED BY SUBJECT.

QUESTIONS AND ANSWERS HAVE BEEN EDITED FOR LEGIBILITY.

QUESTIONS HAVE BEEN REARRANGED ACCORDING TO SUBJECT, AND DUPLICATES HAVE BEEN DROPPED.

ANSWERS MAY VARY FROM THOSE PROVIDED AT THE INFORMATION SEMINARS. UPON REFLECTION AND THE OPPORTUNITY TO CONSULT WITH OTHERS EXPERT IN SUBJECT AREAS, BOARD STAFF HAVE RECONSIDERED SOME OF THE ANSWERS

THE RESPONSES PROVIDED HERE REFLECT THE INFORMED OPINION OF ONTARIO ENERGY BOARD STAFF BASED ON THE DRAFT RATE HANDBOOK ISSUED JUNE 30, 1999. THEY DO NOT REFLECT THE FINAL DETERMINATIONS OF THE ONTARIO ENERGY BOARD IN RP-1999-0034 OR OTHER PROCEEDINGS.

SOME ISSUES ON WHICH QUESTIONS WERE RECEIVED ARE STILL UNDER CONSIDERATION AND ARE NOT INCLUDED IN THIS POSTING.

PBR

Q.1	Why is a price cap mechanism being proposed, when other jurisdictions chose revenue caps? Price caps do not provide an incentive for MEUs (municipal electrical utilities) to promote energy efficiency.
A.1	A price cap tends to simulate a competitive market better than a revenue cap, provide a better balance between risk and reward, and promote more efficient utilization of the existing infrastructure. Energy efficiency may be promoted through other mechanisms of the restructuring.
Q.2	What is the experience with other jurisdictions in terms of the length of the PBR Plan?
A.2	Many jurisdictions have selected a three-year period for their initial PBR term. Three year terms have often been judged to best balance the risks and rewards associated with moving to PBR versus the inexperience and uncertainty that firms, customers, and regulators face in the initial move. These risks arise from unforeseen occurrences or program design inadequacies.
Q.3	Will the OHSC rate order be amended so that OHSC will be subject to the same rate of return principle on contributed capital as will apply to MEUs?
A.3	OHSC's distribution business will be subject to the Board's regulatory framework developed for electricity distribution in Ontario. It is anticipated that, when OHSC applies for a rate order to introduce unbundled distribution rates, the Board's PBR framework will apply.
Q.4	How will PBR data and filings be audited by the OEB?
A.4	The Board's office of the Energy Returns Officer will have direct responsibility for the auditing of utility filings. An auditing, monitoring and compliance programme is being developed by the ERO.
Q.5	How will the Board treat different fiscal year ends for MEUs since rate years will be the same?
A.5	Different fiscal years will not be a problem for the PBR rate mechanism since audited results will not be required for the rate adjustments in March of 2001 and 2002. Audited statements will be filed later in the year (June). However, the IPI requires a common reporting period for distribution utility data in order to calculate the annual Industry Price Index, with the proposed time frames in the draft Rate Handbook assuming a calendar year period.
Q.6	Wouldn't a true earnings sharing mechanism of a 50/50 or 40/60 split of excess ROE (shared between ratepayers and shareholders) provide more incentives for MEUs to improve productivity and to reduce rates?
A.6	The proposal allows the utility to keep up to 100 % of profits up to the capped ROE for the choice of the X-factor (or PF = Productivity Factor) that they choose. Board Staff feel that the proposed PBR mechanism provides maximum incentives and mitigates program failures during this initial period.
Q.7	The Industry Price Index includes "material". What does "material" refer to – inventory, or just carrying costs?

A.7	Material represents expenditures on everything that is not covered by capital or the utility's own labour. Line losses are also excluded – see the response to Q.5 under **Productivity**.
Q.8	What is the end date for the PBR development process?
A.8	The Board intends on issuing the final rate handbook before the end of 1999.

Productivity

Q.1	If annual historical productivity growth is in the range of 0.3-0.9% and the first-generation PBR term is a "learning period", then the proposed minimum X-factor of 1.25% would seem unrealistic. The X-factor should be 0.9% +/- 10%. Explain the rationale for a minimum X-factor of 1.25%.
A.1	Productivity improvements among electric distributors in Ontario averaged about 0.9 percent per year from 1988 to 1997. Half of the analyzed utilities exceeded 1.0% average annual TFP growth, 40 percent exceeded 1.25% and some achieved a significantly higher rate of productivity improvement. In addition, regulators usually add to the historical performance benchmark a Consumer Productivity Dividend (CPD) or "stretch factor" in their calculations when establishing the PBR productivity factor. The stretch factor provides an initial sharing mechanism with customers including anticipated savings (such as lower regulatory costs) and anticipated improvements in a utility's operations resulting from the move to "incentive" regulation.
Q.2	When considering the productivity factor, are all utilities treated the same? If the answer is yes, doesn't this system reward failure and punish success?
A.2	Each utility can select from among the six productivity factor/ROE ceiling options. An individual utility's choice will be based on a number of considerations including the experience, circumstances and opportunities unique to that utility. Furthermore, every utility will be able to adjust its rate ceiling based on the change in the IPI even if its own input prices, say, rose less than the IPI.
Q.3	With regard to the first-generation PBR, isn't it true that those utilities that have made the greatest efficiency gains before PBR are penalized in the ROR that they can achieve, because their productivity gains have already been achieved?
A.3	Based on regulatory reform in other industries and jurisdictions, assertions cannot be made that utilities that have realized high productivity gains in the past are penalized by PBR. There are many ways that a utility can change its operations and have significant productivity opportunities. Historically productive firms may be advantaged by their past management approaches and corporate culture to improve operations, and can often sustain their pace of efficiency improvements when moving to incentive (PBR) regulation.
Q.4	How will PBR deal with utilities that are already performing in the bottom ten percentile of similar utilities?

A.4	Each utility can select from among the six productivity factors. An individual utility's choice will be based on a number of considerations including the experience, circumstances and opportunities unique to that utility. Furthermore, every utility will be able to adjust its rate ceiling based on the change in the IPI even if its own input prices, say, rose less than the IPI.
Q.5	Explain the rationale for removing line loss from IPI when it was included as an input for the TFP (Total Factor Productivity) analysis. What is the incentive to improve line losses in the future?
A.5	The TFP analysis looked at the historical productivity of the industry. TFP or total factor productivity analyzes the growth in a firm's outputs relative to that of all inputs. Line losses effectively are an input for a distribution utility, along with capital, labour, and materials, and so must be considered in the TFP analysis. However, under the proposal in the draft Rate Handbook, line losses will be dealt with through the monthly settlements process, rather than annually through the update to the IPI. A utility will still have an incentive to reduce line losses; a utility can increase its earnings if it can economically reduce its line losses below the five-year historical average embedded in initial rates.

Market-Based Rate of Return

Q.1	Can a utility start making a profit now (in order to pay interest and dividends) or does it have to wait until the retail market opens?
A.1	Once a utility is incorporated and its assets transferred (subject to the appropriate legislation), its shareholders have a right to earn dividends. A utility may choose to apply for rates that would bring them to the ROR cap for 1999. However, with the knowledge that it will need to bring in unbundled rates by market opening, it may be advisable to take customers through one rate change rather than two within a fairly short time period, if the move to MBRR requires a rate change.
Q.2	What is the definition of the effective tax rate in the MBRR?
A.2	It is still to be defined, although it probably will be the average (not marginal) tax rate on before-tax income. For the purpose of the initial rate setting, the utility should forecast what the payments in lieu of taxes (PILs) will be and relate these to net income before PIL in order to derive a ratio to apply to the calculation of MBRR.
Q.3	What is the common equity ratio?
A.3	The common equity ratio is that portion of the rate base (excluding CC) deemed to be financed by equity for rate setting purposes. This does not mean that the utility has to use equity equal to this portion, but it is the deemed capital structure.
Q.4	How is the five-year average ROR [1994-1999 average ROR for utilities with contributed capital in existing rates] determined?

A.4	Please see the Supplement to the draft Rate Handbook, issued on August 12, 1999. The Supplement is available from the Board's PBR web site.
Q.5	Does the ROE ceiling include the return on contributed capital or is the contributed capital return monitored separately?
A.5	The ROE ceiling is based on non-contributed capital equity.
Q.6	Is the ROE calculation based on the actual sales or on normalized sales (normalized for weather, etc., as is the current practice under cost of service regulation)?
A.6	The current practice does not normalize based on weather. In PBR, it will also not be based on weather normalized sales.
Q.7	If the customer base is eroding, what is the effect on rates and ROE?
A.7	There would be a decline in revenue. However, if costs decline at the same rate, then the ROE will stay the same. Conversely, if costs do not decline at, at a minimum, the same rate, then the utility's ROE will decrease.
Q.8	The distribution charge is partially recovered through kW and kWh charges. If energy sales vary (decrease), there is a risk that distribution costs would not be recovered. How can this risk be managed since energy sales will be beyond the control of the LDC?
A.8	There is a risk of a utility not collecting all distribution charges related to throughput and that needs to be handled through management of the business. Conversely, PBR also allows a utility that is effectively and efficiently operating to become more profitable for its shareholders.
Q.9	In order for the distribution utility to achieve a market-based rate of return, the overall rate to the customer would have to be increased 15 to 20% from current rates in some cases. Other than the adverse feedback that would come from the customer base, is there anything to prevent a utility from raising rates to that extent? Would the OEB force a utility to accept a less than market-based rate of return for the wires company?
A.9	While the utility has the right to earn a return up to the market-based rate of return, where there are significant customer impacts the utility should consider rate impact mitigation options, as is discussed in section 3.3.5 of the draft Rate Handbook.

Rates under PBR

Q.1	Why is March 1 the proposed date for rate changes under PBR, when Ontario Hydro worked to January 1?
A.1	Rates effective January 1 would most likely entail the use of estimated/forecasted information (to reflect year-end numbers). Deviation between actuals and forecasts would then need to be reconciled through a true-up.
Q.2	Why is February proposed for data filings, when March would bring in actual year-end power

	billings?
A.2	The power bill is a pass through in the restructured market. As such it does not affect the distribution costs regulated under PBR.
Q.3	If a utility decides not to take its full rate increase one year, can it defer it to another year?
A.3	Yes. Any increase can be phased in up to the ceiling as determined by the price cap.
Q.4	Is the pricing flexibility among rate baskets cumulative over the years? For example, does the $9.10 residential rate in the example serve as the base rate for the adjustment in the subsequent year or does the $9.50 flexibility option actually taken serve as the base rate for the adjustment in the subsequent year?
A.4	The $9.50 actual rate becomes the rate base for the following year's adjustment.
Q.5	In what units will the price ceiling be defined?
A.5	The unit defined should be consistent with the unit of the rate – e.g. $/customer, $/kWh.
Q.6	What happens if a utility selects option F (PF=2.5%, ROE ceiling = MBRR+5.25%) but achieves a productivity growth of 1.25%/yr? Will the OEB require the utility to give 2.5% to ratepayers (in terms of real rate reductions) before the ROE calculation for shareholders?
A.6	The utility must reduce rates, in aggregate and adjusted by inflation, by the PF of the option taken (2.5% in this case) before determining its profitability for its shareholders. In the case where the actual productivity is less than the PF selected by the utility, the ROE earned by the utility will be lower than the ROE ceiling allowable for that utility.
Q.7	Since the variable distribution rate is constant (see table 2-9, Appendix A, page 10), will the OEB permit the utility to more fairly distribute (i.e. re-balance) costs and revenues between small and large customers?
A.7	The fair allocation between small and large customers is difficult to determine in the absence of cost allocation information. However, to the extent that a utility can move the costs between customer classes, the utility has some pricing flexibility as described in Chapter 4 of the draft Rate Handbook.
Q.8	Will there be flexibility in defining customer groupings e.g. including customers with kW loads between 750 kW to 3000 kW as intermediate users, subject to load profile data?
A.8	Yes, if a customer's load profile has significant impact on the rate class's cost of power. If upon market opening this customer chooses an alternative supplier then this customer will no longer affect the default cost of power. If it is a default customer following market opening it will be billed according to the Standard Supply Service Code.
Q.9	If primary metering is installed, does the customer still receive 1% credit on the demand and energy?
A.9	The rate applied to a customer metered on the primary side should be as described in the Standard Application Rates.

Q.10	How is Transformer Loss Credit included? What about dry core transformer charges that were previously approved by Ontario Hydro? What about Streetlight Time-of-Use Rates?	
A.10	The Transformer Loss Credit will continue to apply as stated in the Standard Application of Rates. Approved dry core transformer charges will continue to apply as well, as will as streetlight time-of-use rates (see Appendix A of the draft Rate Handbook).	
Q.11	Is the OEB developing software, much like the UFAP program (previously used by Ontario Hydro) to work with for rate submissions to the OEB? Is this program part of the USoA (Uniform System of Accounts)?	
A.11	The Board is contemplating making a spreadsheet available that will facilitate rates development for the distribution utilities. It will not be part of the USoA.	
Q.12	The Board Staff must have done a calculation of the rates under PBR for an actual utility and compared that with current rates. Will you share this?	
A.12	A summary of the impacts of a market-based rate of return and taxes on utility rates is presented in the Final Report of the Distribution Rates Task Force (May 18, 1999). This document is available from the Board's PBR web site.	

Rate Handbook

Q.1	Will Part B of the final Rate Handbook be like Appendix A of the draft Rate Handbook?
A.1	Yes. It will be a step by step guide.
Q.2	Can you provide a step-by-step calculation for initial rates for a sample utility?
A.2	See Appendix A of the draft Rate Handbook. A spreadsheet will be provided with the final Rate Handbook.
Q.3	Will there be a discussion on the calculation of "rate base"?
A.3	The calculation of the rate base has been included in the Rate Handbook Supplement. The Supplement is available from the Board's PBR web site.
Q.4	Are utilities expected to have Residential Time-of-Use (TOU) rates? Is the 5-year average distribution system loss fixed, or does it roll? In Table 2.1 (of the Appendix of the draft PBR Rate Handbook), shouldn't the monthly hours be actuals?
A.4	No, utilities are not expected to have residential TOU rates. With regard to the monthly hours, 730 was used for preliminary modeling; utilities should use the actual number of hours in each month. The 5-year DSL average is fixed for the life of the first-generation PBR plan.
Q.5	How was Table 4-2 determined?
A.5	The figures in Table 4-2 are based on a simple model that adjusts a hypothetical utility's rates, revenue and operating expenses by assumed changes in the IPI and the PF, and the actual rate of

	productivity change. The resulting returns on earnings are computed for each option for the second and third years and compared with the ROE ceiling for that option. Table 4-2 is intended as an illustrative example, not as an elaborate planning tool. For further discussion, please see the Supplement to the draft Rate Handbook (available from the Board's PBR web site).
Q.6	It appears that the class coincident demands are calculated independently. Will the sum of the class demands and hence the sum of the class COP be adjusted and reconciled to match the system COP? If not, the difference will be attributed to distribution revenue requirement and the initial rate level will not be set at the correct level.
A.6	The percentage of the class demand is the portion of the class's demand peak which is coincident with the utility's demand. The percentage used is based on the 1980's model for the customer class. The demand portion of the class's cost of power is then determined. A reconciliation of the individual classes' cost of power to the utility's total cost of power may be necessary.
Q.7	How should primary metering on high voltage side be accounted for in rate-setting under PBR? Currently there is a 1% discount because the primary meter happens before the allowed-for losses associated with the large users and the customer owns the transformer. The majority of customers are metered on the secondary side so there is an assumed allowance for customers metered on the primary side. The 1% credit recognizes that those that are metered on the secondary side have meter/transformer losses included in their rates.
A.7	Rates should continue to be applied as currently applied, for customer metered on the high voltage side, as described in the Standard Application of Rates.

Contributed Capital

Q.1	What mechanism will the Board have available to approve a charge to replace the current levies available under the *Development Charges Act*?
A.1	A utility can still collect contributed capital (i.e. contributions in aid of construction). However, there is no allowance for a utility to earn a return on contributed capital collected in the future. This approach is analogous to that in the Board's regulation of the natural gas utilities.
Q.2	How would the OEB propose distribution utility companies handle expenses incurred after the set date in 1999 that would previously have been covered by development charges and contributed capital?
A.2	The utility companies are not precluded from collecting contributed capital; they are not allowed to earn a return on revenues collected (after a certain date, currently proposed as December 31, 1999) as contributed capital.
Q.3	What is the rationale in the natural gas market for not earning a rate of return on contributed capital?
A.3	The utility has not invested in capital that is contributed, and, as such, there is no basis for earning a return when there has been no investment.

Q.4	The proposed Rate Handbook does not allow for differential rates. Where you have some customers that contributed capital and others that did not, it seems unfair for all customers to pay the same rate. Currently the CC pays for the capital, and other rates pay for operation and maintenance and for refurbishment of the system. Please explain why differential rates are not allowed.
A.4	Those consumers who contributed capital did so in order to pay the same rates as the existing ratepayers. They contributed the difference between the marginal cost and the embedded cost of the system. The new PBR system assumes that the current rates are just and reasonable and thus that CC customers were not afforded special treatment historically. The OEB is working on the new system expansion guidelines that will include consideration of when new customers might be asked to make a contribution.
Q.5	If the utility is currently collecting CC but, due to the changes in the industry, wants to finance system expansion through rates or financing, can it be added to rates as a transition cost?
A.5	No, it is considered in the market based ROE. Based on the deemed capital structure, utilities have an allowance for the debt portion (1-CER) multiplied by the debt rate (DR), and will be allowed to recapture the debt expense (interest) associated with the debt-financed portion of existing expenditures. Utilities cannot capture capital expenditures in the rates as a transition cost. If the existing rates are not adequate to finance the capital costs of incremental construction, then the utility should consider aid to construction subsidies. The collection of contributed capital will be addressed in the Board's guidelines on system expansion.
Q.6	For a utility serving a rapidly growing area, with up to 60% contributed capital (CC), what is the impact on rates of the proposed treatment of CC?
A.6	Those utilities with a high proportion of CC will find that the upward adjustment to their existing rates related to increases in ROE will be less than those utilities with no CC. Thus, the rate impact that comes from going to market-based rates will be less.
Q.7	If a municipality with significant contributed capital is purchased/acquired or merged with another, how will the contributed capital be treated?
A.7	There would be difference in the treatment of contributed capital. The rate base of the purchased utility would be added to that of the purchasing utility with the weighted rate of return of the last 5 years applied to the CC portion of the rate base of the amalgamated utility.

Line Losses

Q.1	Why set large use line losses at 1%?
A.1	Where a utility has actual data on line losses associated with their large use customers, they should use this data to support their rate proposals. However, the utility will be required to provide evidence in support of its large use line loss. 1% is presented as a default level.

Q.2	Is the 5-year average for line losses a rolling average? In other words, is the average line loss updated each year by including the last year and deleting the data for the oldest year?
A.2	No, it is not a rolling average but a 5-year fixed average over the term of the first-generation PBR, corresponding to the most recent five years for which data are available.
Q.3	The initial rate setting includes a formula using loss figures for the last five years. In two of the last five years, loss results for a utility have been anomalous and unreconcilable, and which give unrealistically low losses of less than 1%. Would a utility be permitted to exclude such data anomalies, provided its submissions justified such exclusions?
A.3	Yes, line losses deviations would need to be justified.
Q.4	A newly restructured utility resulting from an amalgamation may not have 5-year average distribution system losses data. How do we submit rates without this information?
A.4	An amalgamated utility should aggregate the historical data for each of the amalgamating utilities and weight it by proportion of energy deliveries (weighted average loss rate). In the case of a boundary expansion, where the inheriting utility does not have line loss data for its new service area, the utility's historical line losses should be used unless justification for a deviation can be provided.

Transition Costs, Extraordinary Costs (Z-factor)

Q.1	What portion of an "ice storm" expenditure would qualify as a "Z factor"?
A.1	Severe weather, including ice storms, have been part of the history of the industry. Within PBR, ice storm expenditures would need to be examined relative to their historical incidence and severity. In general, costs would be allowed as a Z-factor only for extraordinary events.
Q.2	Is the cost of plant relocation that the utility has to absorb (as the result of the *Highway Act*) a legitimate "Z" factor, subject to materiality?
A.2	That would depend on the materiality of the cost and whether it is or is not a regular cost of doing business.
Q.3	Can you provide a utility with some guidance on a percentage or a cap for transitional costs that would be recoverable through rates? Will the internal labour and purchases required to meet the PBR and the new electricity market be allowed as a transitional cost in the initial rate order?
A.3	It would not be possible to put a cap on transitional costs since it is likely to vary by utility. What the Board can do is to evaluate the prudence of the transition costs incurred. Internal labour costs are already included in existing rates.
Q.4	Please give examples of allowable transitional costs.
A.4	Examples are given in section 5 of the Distribution Rates Task Force Report.

Licensing

Q.1	Who has the right to build new wires? Anyone?
A.1	Anyone who is so licenced by the Board has the right to run a distribution system.
Q.2	Does the LDC have geographic franchise rights for additions to plant within its boundaries?
A.2	Distribution utilities do not have exclusive franchises within their existing service territories. System expansion guidelines are currently being drafted by the Board to deal with the requirements pertaining to additions and replacements of plant.
Q.3	Are distribution utilities going to have to get transmission licences particularly as it relates to co-generation and/or distributed generation?
A.3	The *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* define transmission equipment as equipment used to convey electricity at voltages of greater than 50 kV. Similarly, these *Acts* define distribution equipment as equipment used to convey electricity at voltages of less than 50 kV. Some equipment owned or operated by a generation facility could logically be classified as transmission or distribution equipment, and therefore potentially requires a transmission or distribution licence. However, where the equipment is used to convey electricity (either above or below 50kV) from the generation facility to the grid only, the Board does not anticipate requiring the generator to obtain a transmission or distribution licence. In another case, where the equipment is used to convey electricity (either above or below 50kV) from the generation facility to the grid and/or to other customers, the Board may require the generator to obtain a transmission or distribution licence in addition to its generation licence. If a generator feels they might fall within the second scenario, they should contact the Board's Licensing Office.

Utilities with Self-Generation or Contracted Generation

Q.1	For MEUs that have their own generation, should they do their own distribution cost of service studies?
A.1	It would be appropriate for utilities under any circumstance to do a cost allocation study. However, considering the time limitations to have unbundled rates in place for market opening, the proposal is to defer this requirement to the second-generation PBR plan.
Q.2	For utilities that have their own generation, how will embedded generation affect the allocation of cost of power (COP) calculation and determine the rate base?
A.2	A utility with local generation will need to determine its local costs of power and use a weighted average of its local and Ontario Hydro COP and then apply the model to allocate the total COP to their customer classes. The generation assets are excluded from the distribution rate base.

Service Quality and Performance Indicators

Q.1	If a utility is not currently monitoring its service reliability indices, what is the earliest date it must report these measures?
A.1	Those utilities that are not currently monitoring service reliability indices will need to start doing so at the start of their first-generation PBR plan and will file their first report by March 1, 2001.
Q.2	Will there be an auditing procedure for service quality standards and performance?
A.2	Yes, the Board's Energy Returns Officer is developing an audit process whereby a utility will be required to attest that its performance is meeting the appropriate standards of service.
Q.3	Is the OEB going to provide the utilities with computer programs to monitor service quality information?
A.3	Spreadsheets will be provided that distribution utilities can use for tracking and reporting on service quality and other performance measures.
Q.4	If the historical data of a utility's performance is used as the minimum reliability standard, will each utility, therefore, have its own benchmark or will a provincial standard be developed?
A.4	For the first-generation PBR plan, a utility's past performance will serve as its "benchmark". It is hoped that, with the knowledge gained on the performance indicators during the first-generation plan, it will be possible to set provincial standards for the second-generation PBR plan.
Q.5	Will the CAIDA, SAIDI, and SAIFI reliability indicators be divided into planned and unplanned outages?
A.5	The intention is to include both planned and unplanned outages. It is our understanding that the common industry practice is to include both of these in reported statistics.
Q.6	Regarding reliability standards, how do you deal with momentary outages (less than 1 minute in duration) that can still have significant economic damage to customers?
A.6	The members of the Implementation Task Force felt that dealing with outages >1 minute in duration was reasonable for a performance indicator. However, this does not preclude utilities from setting operational standards to deal with outages of <1 minute duration for their own use.
Q.7	In some utilities' operating territories, many, if not most, cable locates, are from other than customers/ratepayers. For example, they can involve developers planting trees in subdivisions, telecommunications and cable TV companies installing fibre and cable, road authorities doing road maintenance and widening, and municipal water/sewer maintenance and expansion. Does the service quality measure pertain only to cable locate requests from ratepayers?
A.7	The Board is interested in all cable locates, not just requests from property owners.
Q.8	The service quality indicators in the draft Rate Handbook look to be internal measures. Have the appropriateness of these indicators and standards been checked with customers? For example, did anyone ask a sample of customers what they expect or need?

A.8	The service quality indicators were proposed by members of the Implementation Task Force, which included representatives of customer groups. The Task Force also recommended that the Board conduct customer satisfaction surveys. The Board may undertake such surveys to better understand customer issues. Customer complaints monitoring by utilities and the Board will also provide relevant information on issues of concern to ratepayers, including those related to service quality.
Q.9	One of the objectives of the OEB is to protect the interests of consumers with respect to price, reliability and quality of electricity. What mechanisms of the PBR ensure that customers receive adequate quality of electricity?
A.9	The link between quality and rates will be addressed more directly in the second-generation of PBR. At this point, the OEB and industry need to develop some experience with these performance measures before deciding on standards and regulatory remedies for sub-standard performance.
Q.10	Why do the proposed performance indicators not include measures of Health and Safety, such as the number of lost time injuries and WSIB rate?
A.10	As Government agencies already set health and safety guidelines, the Cap Mechanism Task Force felt that there was no need for the Board to do so.

Mergers, Amalgamations, Acquisitions and Divestitures

Q.1	On a sale of the utility will there be a hearing?
A.1	The Board is developing guidelines for regulatory requirements that would apply to mergers, amalgamations, acquisitions and divestitures in the Ontario electricity industry. These guidelines will cover situations such as the sale of all or part of a distribution utility.

Consumer and Industry Education

Q.1	What efforts are being undertaken by the OEB to ensure that all LDCs will be prepared for market opening?
A.1	Utilities can keep up with OEB activities on regulatory issues relating to industry restructuring through our website. There are a host of other activities happening at the Board (e.g. Consultation on licence codes) and it is hoped that utilities will continue to participate. The OEB is working with the Ministry of Energy, Science and Technology as well, and with the IMO and industry associations to enhance utility awareness and preparedness.
Q.2	What will the OEB do to educate consumers on the industry and regulatory regime?
A.2	The OEB is holding similar seminars for licensing as it did on the draft Rate Handbook, and is working with the MEST to develop an information package to educate consumers on the coming changes in the marketplace. Part of this will happen in concert with the market opening.

Standard Supply Service

Q.1	Will the Rate Handbook address commodity pricing for default customers?
A.1	The commodity pricing for default customers will be in accordance with the Standard Supply Service Code.
Q.2	If Standard Supply Service (SSS) moves to a fixed price offering rather than a spot price pass-through, would the utility's management of this be captured through the price cap.
A.2	This issue will be handled through the Standard Supply Service Code being determined by the Board.

Second-Generation PBR

Q.1	How will rebasing work as we move into the second Generation PBR?
A.1	Rates will be rebased for second generation PBR based on the utility cost allocation study with an allowance for an ROE appropriate at the start of the second generation PBR plan. Rebasing may take into account some of the productivity gains achieved during the first generation PBR. As a result of experiences during the first generation PBR, the Board may include other considerations.

Miscellaneous Topics

Q.1	When will contestable services be defined by the OEB?
A.1	This has not been decided yet. At the time that the PBR task forces were established, a fifth task force was to have dealt with this topic; however, the formation of this task force was deferred. The Board anticipates addressing this issue in the coming months.
Q.2	How do utilities as wire companies handle water heater and sentinel light rentals that are only a small part of the business?
A.2	Wire companies' water heater and sentinel lights rental programs are not monopoly distribution services. How these programs are handled was to have been dealt with in a fifth task force dealing with contestable services. See the previous answer.
Q.3	What determines when a rate hearing, written or oral, is required by the Board?
A.3	The decision is made by the Board subsequent to the public notice being issued and any submissions have been received. Based on intervenors' concerns, and on the nature of the proceeding, the Board will make the decision of whether a hearing is required on a case-by-case basis, and can decide the type of hearing (oral or written) to conduct.

Q.4	Cornwall Electric (CE) was never regulated by Ontario Hydro. Will CE be regulated by the OEB? Will existing rate guarantees with the City, in effect until July 1, 2001, be valid? What happens to existing contracts with customers? Does the existing rate design have to be changed? What happens to current wholesale contracts? What is the cost for a rate application with the OEB? If a utility does contract work for others, will revenues earned factor into the rates calculation?
A.4	Cornwall Electric meets the definition of a distributor as set out in s.56 of the *OEB Act* and would therefore be subject to regulation by the Board. Whether Cornwall Electric would be exempt from any of the provisions of the *Act* is a matter for the Ontario Government to decide. The Rate Handbook is intended to apply to all distributors in Ontario, but is intended to be a guideline that will not fetter the discretion of the Board in addressing the individual circumstances of any particular distributor in rate applications.
Q.5	Can we charge what the market will bear for pole attachments i.e. Bell or cable TV?
A.5	This may be an issue that would involve the CRTC (Canadian Radio-television and Telecommunications Commission).
Q.6	Where does the MEA unbundling model fit with the PBR draft Handbook?
A.6	The MEA unbundling model referred to is a cost allocation model that is separate from the rate unbundling method presented in Appendix A of the draft Rate Handbook.
Q.7	What happens to the $.60/kW credit for customer-owned transformers?
A.7	For first-generation PBR the transformer allowance will remain constant at $0.60/kW.
Q.8	What is the earliest date we need to provide a new load profile model (load data research)?
A.8	While a date has not been set, it is contemplated that it will be required for the second generation PBR plan.

September 10, 1999