Meeting Notes #2
Cost Allocation Working Group
Thursday, March 27, 2003
9:30 a.m. - 3:15 p.m.

1. Review of Developments Since Last Meeting

Staff reviewed new timelines set out in Board correspondence. This working group will focus on what data utilities should start collecting (e.g. on January 1, 2004), with a view to later completing their cost allocation studies (e.g. in the Spring of 2005).

Issues relating to how to complete the cost allocation studies (e.g. use of a "minimum system" approach) will be examined later.

General concern was expressed over the cost to the industry of completing the studies. The key role played by the Minister of Energy, under Bill 210, in approving new rate applications was discussed. Staff noted the financial concerns expressed and explained the subsequent sessions would examine in detail how good technical results could be obtained in a cost-effective manner.

Whether the Badali Report had any direct implications for the mandate of this phase of the cost allocation working group was discussed. It was thought the primary goal of the cost allocation studies was to check for any cross-subsidization between rate classes, and that pure rate design issues (such as the merits of fixed v. variable rates) should be examined later in the planned 2006 "going-in rates" consultations

2. Review of Working Group Schedule

The future agenda of the working group was discussed and based on participants feedback, two extra items were added to the agenda:

- What data should be collected as of January 1, 2004 to better inform subsequent rate design debates.
- The significance of direct assignment of costs.

Staff also explained that members of the work group would be asked to kickoff the discussion on each technical topic, and that the entire group would be asked to prepare a report by around June 2003.

3. Goals of Cost Allocation Studies

After the group discussed widely accepted principles of rate setting (as found, for example, in Bonbright), it was agreed that the primary purpose of the cost allocation studies was to ensure fairness between rate classes. The paramount role of cost causality in determining fairness was acknowledged. In this regard, the Board's comments on cost allocation in RP-1999-0034 (para.2.0.13) were highlighted ("utilities will be required to undertake cost allocation studies to better align rates among customer classes with cost causation in second generation PBR").

The importance of coming up with practical ways for the Ontario electricity distribution sector to complete potentially 90plus cost allocation studies was stressed.

The group also acknowledged rate stability as a secondary goal. There was some discussion about the potential role of efficiency, and it was decided it would be examined further at the rate design stage.

4. Alternative Methods of Allocating Demand-related Dx Costs

In a discussion kicked off by Bill Harper, Roger White and Hydro One, the strengths and weaknesses of various methods of allocating demand-related distribution costs (coincident peak, non-coincident peak ("NCP"), average and excess) was debated. Experiences in other jurisdictions were discussed, and it was noted NCP is the method most frequently used to allocate demand-related distribution costs (while the other approaches are widely used in the generation and transmission sectors).

After reviewing the merits of the various approaches, the initial views of the majority of the group was that:

1) NCP should be the general method (i.e. "default") used to allocate demand-related distribution costs in the forthcoming cost allocation studies, since:

- In general, distribution facilities are the facilities that are closest to the customers and are sized to meet the individual customer's demand and not the aggregated demand.
- Using non-coincident demand would better match cost allocation between customer classes with costs recovery from the same customer classes.
- Non-coincident demand would allocate a fairer share of costs to customer groups that use the facilities, but are not consuming much electricity at the time of the LDC peak.
- Customers would have better control over their non-coincident demand.
- Non-coincident demand is generally more stable and easier to forecast.
- Non-coincident demand is relatively easier to measure, track, and understand.
- Development of DSM initiatives may be easier if the starting basis is NCP demand.

2) Under some circumstances, use of CP could be an attractive choice to allocate demand-related distribution costs (e.g. with sub-stations and associated subtransmission lines for utilities with a single point of supply). It was therefore recommended that Ontario LDCs be given the option of using the coincident peak method to allocate demand-related Dx costs in their forthcoming cost allocation studies, provided they provide a reasonable explanation of their preference for using the CP method. To provide assistance to subsequent parties, the working group would endeavour to provide some comments as to when LDC use of CP may be seriously considered.

3) The group did not believe the OEB should mandate use of Class 1 NCP, where the non-coincident demand allocator is determined by considering all of the customers in the class as one service point and determining the associated maximum annual demand for the class. The group believed that, in some situations, it may be appropriate to allocate demand-related distribution costs using NCP for each customer class averaged over a number of months (for example, 12 NCP has been by Hydro One Networks). It was agreed this choice should be left to each utility, who could justify a particular choice based on its unique circumstances. The working group would attempt to issue some general comments to assist utilities.

4) To ensure flexibility in completing the studies, both class and customer NCP values should be gathered.

Initial Decision: Bill Harper would prepare a short set of guidelines, reflecting the above, for future review by the group.

4. Other

- A copy of a October 1, 1996 Ontario Hydro document entitled “Cost of Service Methods: A Guide for Ontario Municipal Utilities” was made available for the Board’s library.

<u>Attendance</u>

Bluewater Power - Ron LaPier, Kathy Gadsby
Brantford Power - Heather Wyatt
Canadian Niagara Power Inc. - Doug Bradbury
Chatham-Kent Hydro - Jim Hogan
Guelph Hydro - Jim Fallis
Hamilton Hydro - Cameron McKenzie,Terry Karp
Hydro One - Mike Roger
Hydro One Brampton - Scott Miller
London Hydro - Ken Walsh, Dave Williams
Milton Hydro - Don Thorne
Newmarket Hydro - Gaye-Donna Young
Oakville Hydro - Gary Parent
Ottawa Hydro - Lynne Anderson
Toronto Hydro - Anthony Lam
Thunder Bay Hydro - Cynthia Domjancic
Veridian - Laurie Stickwood
Woodstock Hydro - Ken Quesnelle

Econalysis - Bill Harper
ECMI - Roger White, Andy Bateman
EDA - Maurice Tucci; John Wong
RCS - Mike McLead; Peter Ioannou
Upper Canada Energy Alliance - Jim Richardson
FOCA - John McGee
Bob Mason
Chris Amos
Barker, Dunn & Rossi - Paula Zarnett, Neill Winger

Board Staff:
John Vrantsidis
Neil Yeung