Meeting Notes #4
Cost Allocation Working Group
Wednesday, April 9, 2003
9:30 a.m. - 3:15 p.m.

1. Use of non-coincident peak method

The group reviewed draft wording recommending use of the NCP as the "default" method for allocation of demand-related distribution costs, with CP as an option if a utility can make a case for its use. Bruce Bacon was asked to reword the document to incorporate the group's further comments.

2. Length of time data should be collected

Hydro One kicked off a discussion on the question of what length of time sample load data should be collected.

a) It was noted North American texts (e.g. NARUC's Electricity Cost Allocation Manual, page 178) suggest that a minimum of 12 months worth of load data be collected. After discussing the pros and cons of the issue, the working group recommended that Ontario LDCs also collect 12 months of load data. The reasoning was as follows:

- Consumption patterns will vary by month, and this will be true for both residential and GS customers
- Residential customers' consumption patterns are different throughout the year, for example heating or cooling load
- Seasonal customers consume load during specific seasons, for example ski resort operators or summer cottages
- Cost Allocation studies are usually based on 12 months worth of financial data in order to come up with suitable charge mechanisms, i.e. on a monthly basis
- 12-month load data is required for revenue forecasting, which is important in testing whether the derived rates will recover the appropriate revenue requirement.
- Metering errors can be "bridged" with data from good months
- Transmission passthrough rates are derived based on coincident peak for the class, therefore, 12 months data is needed to capture coincident peak.

b) It was mentioned that if data were collected for 2004, then the weather that year may or may not prove to be normal. The group undertook an initial discussion of the advantages and disadvantages of weather "normalizing" the load data collected. The group agreed to look into the issue again during this series of consultations.

c) The group was referred to comments at page 9-11 of the AEIC Load Research Manual mentioning certain cautions about the use of historical load data. The point will be discussed in future sessions.

3. Collection of interval v. non-interval load sample data

Pauls Zarnett kicked off a discussion of this topic. The group ultimately agreed that, for sampling purposes, interval load data should be collected, in order that both the class and customer NCP can be calculated (as previously recommend). The reasoning was as follows:

- For clarity in the discussion, the terminology NCP can be used to refer to two different values:
  - Individual customer NCP – maximum demand of a single customer in one time interval, regardless of when this occurs, or the total of such individual customer maximum demands
  - Class NCP – the maximum consumption of the whole class, in total, in any one interval.
- A demand meter on a customer's service measures and stores the maximum consumption of the customer in a period of about 15 minutes, but does not record the time of occurrence. A demand meter is all that is necessary to gather measurements of individual customers' maximum consumption. The sum of these values is the individual customer NCP, and may, in certain circumstances, be an appropriate demand cost allocator.
- With respect to class NCP, the term "non-coincident" applies between different classes—i.e. each class peaks at a different time which may or may not be the time of the system peak. However, the class peak is a "coincident" peak with respect to the customers within the class.
- Therefore, in order to determine class NCP by metering individual customers, the data must allow the analyst to compute and compare, for each interval, the sum of all the customers' consumptions in that interval, and select the maximum of those sums. To obtain this data by measurement, an interval meter is therefore required.

NB - It is understood that in order to compute the contribution of each customer class to the system peak, time-related interval consumption data will also be required by utilities using the CP option.

4. Potential cost of load research sampling

Any utility which will commence its own load research programme, or which will contribute new load data to a group effort, will be required to install sample meters.

Two metering specialists, guests of Newmarket Hydro, discussed some of the practical details of various meters available on the Ontario market at present.

In general, more sophisticated "three-phase" interval meters were required to sample GS customers, while cheaper "single-phase" interval meters were available for residential.

The cost of purchasing a sample meter would vary according to the type of technology, supplier, etc. By way of illustration, the group was informed that the cost of a telephone technology- based interval meter for residential class use could vary from $200 to $350 each (some utilities were budgeting $400 per meter) . For the more complex meters needed to sample the GS class, per meter acquisition costs could be double that amount.

Numerous types of interval meters are available, and each has its own advantages and disadvantages in terms of upfront cost, ease and expense of installation, technology (radio v telephone v. hybrid). The expert guests thought an actual utility could use a variety of meters, to best suit specific circumstances.

It was stressed that the total load research budget should include the cost of reading the sample meters (the group was informed this could range from $1.00 per meter per month to $30 per meter per month).

In addition to the cost of installing the sample metering, sophisticated software (e.g. MV 90) is required to read the data. Some larger utilities have already purchased such software, while LDCs others would have to retain an external service provider.

5. Timing of load research programme

Veridian and Thunder Bay kicked off a discussion of what steps, and how long, it might take to get a sample metering programme ready.

The group agreed the time estimates should take into account the following:

- utilities would first need to decide how many sample meters they need and make a decision from whom they should be sourced
- time should be budgeted to get customer approval for installation of a sample meter (some utilities cautioned this has proven time consuming in the past)
- vendors report some time (e.g. 10 weeks) would be required to fill orders
- the new meters should be installed and debugged for a while (e.g. a month).

Some group members commented 6 months to complete the above was a tight schedule, but “do-able”. Others cautioned that if a serious problem emerged in any of the above steps, a January 1, 2004 target date would difficult to meet. It was also mentioned some utilities have limited practical experience working with residential class interval meters.

After considering the various points, the group concluded that its final view on whether a January 1, 2004 start date for the collection of updated load data is realistically achievable would depend upon what method was proposed and accepted (e.g. if certain utilities agreed to update the province-wide load curves and the Board allowed use of the same, this could *eliminate the need for the remaining utilities to install sample meters,* unless they wanted to introduce a new rate class, etc.).

c) It was noted that it was commonly accepted North American practice to allow the use of either billing-quality meters, or cheaper sample meters, for purposes of load research.

The group recommended that such flexibility be allowed in Ontario, provided the sample meters were within plus or minus 2% accuracy. Note other data systems such as SCADA may not meet that level of accuracy. It was also agreed that the above recommendations should apply to any meters used to sample clusters (assuming sampling at the cluster level is eventually allowed).

The group asked Woodstock and Newmarket to produced some draft wording reflecting the above.

d) Participants voiced concerns over obtaining consent from randomly-selected customers to install sample meters. It was asked that the OEB somehow inform customers that some of them may be asked to participate in a load research programme, so that customer co-operation would be promoted.

6. How many rate classes need to be metered

The group discussed the merits of allowing the load profile for one class to be determined as a residual if the load profiles of all the other rate classes were known.

The group discussed the advantages (e.g. lower overall cost of metering) and potential disadvantages (some group members were concerned the residual class might pick up an excess share of any measurement errors).

It was also discussed if it would be preferable to measure the residential class (since it is generally more homogeneous and hence easier to sample), and deem the GS class (which is more heterogeneous and hence generally harder to sample). However, it was commented that utilities have many interval meters already in place among GS users.

After considering the various pros and cons, a majority of the group tentatively decided to recommend that if highly accurate results were obtained for the other classes (e.g. plus or minus 10%, at a 90% confidence level), then it would seem intuitively reasonable to allow the load profile for the final class to be deemed as the residual. If this proves to be the case, each utility could then be given the option of deciding, based on its own circumstances, which class load profile (i.e. residential or GS<50 kW) should be calculated as a residual. A write up was requested for further review and comment.

[Editor's note: The group obtained a copy of Ontario Hydro Report R&U 79-5 entitled Load Research for Cost of Service Studies, which cites at page 67 examples of two actual load survey programmes in which it was decided that certain general service class customers should be left as the residual.]

Attendance

Brantford Power - Heather Wyatt
Canadian Niagara Power Inc. - Doug Bradbury
Chatham-Kent Hydro - Jim Hogan
Guelph Hydro - Jim Fallis
Hydro One - Mike Roger
Hydro One Brampton - Scott Miller
London Hydro - Ken Walsh, Mark Steeves
Newmarket Hydro - Gaye-Donna Young, Dave Akersm (and two guests K. Mills and J. Forsyth)
Thunder Bay Hydro - Cynthia Domjancic
Veridian - Laurie Stickwood
Whitby Hydro - Ramona Abi-Rashed

Econalysis - Bruce Bacon
ECMI - Roger White, Andy Bateman
EDA - Maurice Tucci; John Wong
RCS - Peter Ioannou
Upper Canada Energy Alliance - Jim Richardson
Chris Amos
Barker, Dunn & Rossi - Paula Zarnett
AMPCO - Ken Snelson

Board Staff:
John Vrantsidis
Neil Yeung