

# Meeting Notes #11

## Cost Allocation Working Group

June 26, 2003, 9:00 a.m. - 4:30 p.m.

### **A) Group Final Conclusions on Sampling and Load Data Collection**

At this session, the group undertook its final discussion of the various issues related to the commencement of the collection of load data in 2004. The goal was to reach conclusions for the upcoming Report the working group will issue on these topics (which were the core “deliverables” identified in the Board’s original issues list).

#### **Need for Updated Load Data for Cost Allocation**

The working group understands the need for updated load research data to support the cost allocation studies to be filed in 2005 (in respect of 2006 rates). In specific, the load data will be a key input to the demand allocators. Every potential demand allocator examined by the group (1NCP, 12NCP, CP) requires load data. Because 12 months worth of interval load data information is recommended to be collected, the data will be comprehensive enough to support use of a wide variety of demand allocators.

#### **Use of Interval Meters Recommended For Load Data Collection**

To gather the full range of load data needed for cost allocation purposes (namely both class and customer NCP), the group recommends that interval meters be used in the load research program.

The group had previously examined the cost of acquiring, installing and reading various types of interval meters. While these issues were not discussed again in the wrap-up session, the forthcoming Report will provide full details (the group wishes to stress that meter acquisition costs are only a part of the total cost).

#### **Statistical Approaches Recommended**

The group had previously agreed that load research should be undertaken using methods that can produce results which are statistically verifiable. The group’s conclusions and recommendations, as discussed below, addressed statistically-based techniques only. (Note the group had earlier discussed some load data collection options that would not produce statistically verifiable results.)

### Sample Design Accuracy

For purposes of designing the upcoming load sampling programme, the group recommends Ontario follow the PURPA standard (the sample accuracy level formerly specified in U.S. federal legislation, the *Public Utilities Regulatory Policies Act* of 1978).

The group notes this figure is cited in the standard North American load research publication (AEIC Load Research Manual, 2<sup>nd</sup> Edition), and the group understands it is the standard generally followed elsewhere in Canada as well.

Based on its reading of the AEIC Load Research Manual, the group understood the PURPA standard to be plus or minus 10% at a 90% confidence level.

Note: A detailed overview of the 1978 rules can be found in the APPA publication “Cost of Service Procedures for Public Power Systems.” It was clarified there that the above PURPA figure is “only a target to be achieved in determining sample size rather than a standard”.

### Flexibility in Sampling Techniques

The group had earlier discussed the merits of alternative load sampling techniques. The group’s final conclusion was that an individual LDC (or group of LDCs) be allowed the flexibility of using any of the generally accepted sampling methods discussed in the AEIC Load Research Manual, 2nd Ed.

As a result, Ontario utilities would be free to decide whether to use a stratified sample, and if so, how to stratify (for example, page 4-11 of the above Manual discusses stratification by monthly energy usage versus type of end use).

It was expected that, as a practical matter, Ontario utilities conducting load research on a co-operative basis would use the same sampling method. (The provincial load data research group has come to a consensus on the matter.)

### First Option re Collection of Load Data - “Go-Along” Approach

The group felt it was important that every LDC in the Province be given the option of conducting its own load data research (using statistically-verifiable techniques).

As a practical matter, the group believed this was the highest cost option. At the moment, more than 40 utilities serving around 80% of the users in the Province have instead formed a co-operative load research group. The working group was not aware of any electricity distributor in the Province that was planning to conduct a load research program on its own.

### Second Option re Collection of Load Data - Group of adjacent LDCs sharing data

This approach was extensively discussed in earlier sessions. A GTA group of utilities had seriously considered this approach, but in the final analysis the cost of undertaking statistical analysis to support the results was such that a single province-wide approach became more attractive. As a result, at the wrap-up session no member of the working group was planning to join or form an independent local load research group.

### Third Option re Collection of Load Data - Province-Wide Co-operative Initiative

The working group believes this approach will produce statistically high-quality results in the most cost-effective manner. The group further understands such co-operative approaches are being followed in several U.S. jurisdictions (for example, Virginia).

- It should be noted the present Ontario proposal follows the cooperative load research approach suggested by the prestigious US Electric Utility Rate Design Study (sponsored by NARUC, APPA, EEI, EPRI). See Volume No. 74A, "The Rate Design Study: Load Research", Volume 1 (Nov. 1979), page 4-6.

*Economic Advantages:* Ontario currently has more than 90 utilities. If each utility were to conduct its own load research, and assuming the minimum of at least 30 meters for each utility, the total sample size required by 90 utilities across the province would have been at least 8,100 meters. The actual number of meters required by utilities to construct a statistically valid sample would be much higher because larger utilities would require substantially more meters. The provincial load data research group, in contrast, plans to install much fewer meters (around 700 or less for the residential class, for example, with statistically valid results still expected).

*High Quality Technical Results:* To ensure reliable, high-quality results, the working group recommends that any new Province wide initiative be organized along the lines of earlier province-wide load data research programs (as discussed in prior meetings). In specific, load data be collected from a geographically diverse group of utilities, representing both the urban and rural distribution system. The ultimate goal should be to gather load data that meets the PURPA accuracy targets.

The working group facilitated the development of a specific proposal (see below) which was felt to be a 'win-win' situation for all utilities, and their customers, in Ontario.

### Minimizing Cost of Interval Meters Used in Load Research

If an LDC decided to go alone, the working group understands that it could require at least 30 new meters for each rate class under study, even for the smaller utilities, in order to get a statistically valid sample, properly stratified by selected groups. The working group cautions that the load research work could be particularly costly for smaller utilities. Total cost of each sample meter installed would include acquisition

costs, installation cost, and monthly meter reading costs. The total costs of a GS interval meter is significantly higher.

The evidence considered by the working group confirms that a province-wide approach, rather than an individual utility approach, would minimize the load data acquisition costs for the smaller LDCs (the same conclusion is true for all LDCs in the Province).

#### Load Shape Analysis and Weather Adjustments

The working group notes that in order to prepare utility-specific load shapes by rate class, adjustments on weather are usually required. In addition, adjustments are required for the time period in the load shape analysis because days, weeks and holidays are different between years. (Note the group did not discuss the weather normalization required for calculating revenue; in such cases, different methods may be used, such as using the average weather conditions rather than the extreme peak values.) The working group has not yet drafted its final recommendations on this topic (see further comments below), but notes the Board will be required to decide 1) should all LDCs be required to weather adjust their load data curves, and 2) what weather normalization procedure should be followed. The group believes the choice of method may significantly impact CoS results.

#### Rate Classes and Load Research Program

Similar to the conclusions reached by the 1998-2000 MEA Task Group for Unbundling Cost of Service (which included participation by LDCs, OEB staff, and two sets of consultants), the number of existing rate classes were considered sufficient by this working group and should be used as the starting point for designing the load data research sampling program.

Some LDCs expressed an interest in more GS classes, and it was hoped the great amount of GS>50 kW load data to be collected through existing meters would allow some consideration of such as issue, along with the issue of whether the GS >50 kW boundary should be changed to say 100 kW.

The working group suggests every Ontario LDC decide as soon as possible if it wants to use new rate classes in their 2006 rates submission. It should not be assumed that the provincial load data sampling program will create sufficient load data to support the additional rates classes an individual LDCs may wish to introduce. Moreover, some of the rate classes currently in place amongst certain LDCs may not be sampled in the province-wide initiative.

**It is recommended each LDC carefully review its own particular circumstances and decide if additional defensible load research work is required to support an existing or new rate classification.**

It is the working group's understanding that most Ontario utilities use the following rate classifications (please note more sub-groups are used by the rural distributors):

- Residential
- General service less than 50 kW
- General service greater than 50 kW
- Large user (from 1000 kW to over 5000 kW customers)
- Lighting (street and sentinel lights)
- Unmetered loads.

*Data needed for all rate classifications?*

The group also noted the DRH contains some comments which may be read as suggesting some rate classifications do not require separate cost causality information. The working group requests that the Board clarify its position on this matter.

*Establishment of a Centre of Excellence for Load Research*

The working group notes that the Board will likely require on-going load research work to support future rate applications. Since it is costly for utilities to conduct load research work separately, it would make sense to establish a load research centre to coordinate future load research work undertaken by utilities in the province. The working group recommends the establishment of a Centre of Excellence for Load Research in Ontario to help utilities undertake load research work on an on-going basis, either funded publicly by the government or co-funded with utilities.

The working group also notes that load research data coordinated by the Centre would be useful to help in the design and assessment of demand-side management programs that may be requested by the Board in the future.

*Timely Approval of Methodology Used by Load Research Study Group*

The working group notes the importance of using good quality load research in the cost allocation study. The working group also recognizes it would be cost-effective for utilities to jointly participate in a load research study, sharing the data and cost of a consultant who would provide guidance throughout the execution of the project, including load research methodology, sample design, sample selection and load analysis.

Currently, there are more than 40 utilities that are interested in participating in a joint effort, representing about 80 percent of total electricity customers in the province. The proposal to be advanced will provide load data that is both accurate and cost effective. The working group urges the Board to provide early approval of the methodology to be used by the load research study group (details are provided below), to allow utilities to start collecting the appropriate load data as soon as possible.

Decision(s) Requested from the Board

In light of the considerable amount of time and expenditures planned to be spent by utilities, it is requested that the specific merits of the proposed Provincial initiative be decided upon by the Board at the present time. If this occurred, this complicated sample design issue need not be added to the issues list of the already wide ranging “going-in rates” hearing. Any licensing concerns the regulator may have about data sharing need to be addressed also. This may best be dealt with by the OEB supporting the approach of LDCs sharing data, as long as customer confidentiality is maintained.

**B) Specifics of Proposal by Province-wide Load Research Study Group**

Membership

At present, more than 40 utilities have expressed interest in participating in the province-wide load research project, representing about 80 percent of total electricity customers in the province. These utilities are:

**Central Region**

Aurora  
Brampton  
Burlington  
Enersource Mississauga  
Hamilton  
Hydro One  
Innisfil  
Markham  
Milton  
Newmarket  
Oakville  
Orillia  
Parry Sound  
Richmond Hill  
Tay  
Toronto  
Vaughan  
Veridian

**Eastern Region**

CNP: Gananoque  
Hydro One  
Ottawa

Rideau St. Lawrence  
Veridan: Belleville

**Northern Region**

Chapleau  
Hydro One  
Kenora  
North Bay  
PUC  
Sudbury  
Thunder Bay  
West Nipissing

**Western Region**

Blue Water  
Brantford  
Chatham Kent  
CNP: Fort Erie  
CNP: Port Colborne  
Enwin  
Hydro One  
London  
Westario

**Plus** Potentially 6-8  
more utilities

### Rationale for the Joint Study

The following explains in greater detail why the working group believes it makes sense for LDCs to work together on a co-operative load research project :

- Costs of collecting new load data on selected customers will be spread between all participating utilities;
- Sample size of load research for participating utilities would be smaller than if the utility decided to undertake the load research sampling on their own;
- Utilities will be able to share the experience gained in collecting the load research data and will be able to learn from other participating utilities with respect to the overall process;
- Presenting the information to the OEB as part of a Rate Submission will be easier as many utilities will be using the same approach and the OEB will have been familiar with the methodology;
- Utilities will be able to take advantage of the technical knowledge residing in Hydro One on developing load profiles and weather normalization techniques, as opposed to having to develop the expertise on their own, or buying it from another source;
- The validity of the methodology used to collect the information will be supported by an external consultant paid for by a group of utilities, as opposed to a utility having to hire their own expert;
- A load research expert with Ontario-specific experience has been retained by the study group to provide guidance on research methodology, sample design and selection, as well as load shape analysis; and
- Any legal or licensing concerns about load data sharing can be collectively addressed, with support of the OEB.

### Proposed Load Research Methodology

- The study group's preferred research methodology is to focus on residential customers because this group is relatively homogenous and can be modeled more easily than the general service less than 50 kW classification. The approach is best explained using the following simplified equation:

Utility total system load shape (minus) interval customers load shape (minus) street light & sentinel & scattered unmetered load shapes (minus) residential load shape (equals) general service load shape.

Where:

- Utility total system load shape, and interval metered customers (Large and Intermediate Users), are metered.
- Street light load shape is already approved by OEB. Assume apply to sentinel lights also.

- Deemed load profiles (scattered unmetered loads) will also need to be taken into account.
- The residential class load research will likely require the installation of about 600 to 700 new interval meters randomly selected and stratified by: different regions in the province, by utility, and by different end-uses, including both urban and rural representation. The end-use approach for sampling is used because such data is available (residential load shape will be analyzed in 4 end-uses: base load, electric heating, electric water heating and air conditioning), while information is not easily available for an alternative approach that requires different strata of average consumption statistics of all utilities in the province. The end-use approach is also preferred because it requires significant smaller sample size than the average consumption approach. (While the average consumption approach has the advantage of not requiring explicit appliance saturation information, the cost of metering will generally be higher because as much as 4 times as many meters will be needed under this approach.)
- The general service > 50 kW classification will be analyzed using available existing interval meters from the study group. Preliminary review of existing interval meters owned by participating utilities shows that there will be significant amount of general service interval meters (in excess of 4,000 meters) available for analysis. It is hoped that this huge sample will provide the basis for good analysis for various strata within the current GS>50 kW grouping. Due to the significant sample size of existing general service interval meters, there is flexibility in allowing changes in general service sub-groups, such as moving the GS 50 kW boundary to 100 kW.
- The working group originally proposed the load research methodology sample all classes but one, and then deduce the load profile of the final residual class (it was noted some prior Ontario Hydro load research studies had also accepted calculation of the final class as a residual). The expert retained by the provincial group was asked if there was a serious potential risk of undue error being allocated to the residual class. According to the expert advice received, the mean square error of the residual class is the summation of the mean square errors of the other classes. If the objective is to minimize the mean square errors of all classes, the sampling should focus on the ones with the most homogeneity within classes and with the most available accurate information. The residential class is the class with the most homogeneity. The general service class of greater than 50 kW tends to have the most existing interval metered loads. It would make sense to choose the general service class of under 50 kW as the residual class. Because the total utility load is known with certainty, sampling all classes would not contribute further to minimizing the summation of mean square error of all classes.
  - It should be noted that because of wide-spread LDC support, the province-wide load research study group will now have access to a few hundred interval meters in general service of less than 50 kW. Therefore the proposal

has been revised, and *data from these interval meters will now be used to fine-tune the load analysis for the general service less than 50 kW customers.*

### Tentative Schedule of Load Research Study

The schedule of the load research study group is considered tight, but it will meet the time line set by OEB to commence load data collection in early 2004 (assuming timely Board approval is obtained of the sampling program).

- Assuming any sample design concerns that may be raised by the Board's load data expert are successfully addressed at an early date, interval meters could be installed as early as the Fall of 2003 (that target date will be moved back somewhat if further consultations on the forthcoming Report are organized).
- Appliance survey of interval metered customers will be undertaken to collect appliance data relating to heating and cooling equipment saturation, house size, income level and number of people living in the house. This is important information that should be collected in order to prepare good quality load shape analysis.
- At least twelve months of interval data will be gathered.
- The load shape information resulting from new research (including residential and general service customers) will be used to compare with and update existing available load shape information (see IMO web site). If appropriate, the Bayesian statistical technique will be used.

### Sharing of Load Data

The province-wide load research group plans to confirm with the OEB that sharing of load data within the participating group (40 plus utilities) is permissible from a licensing perspective. Other legal issues regarding privacy of data may also need to be addressed by participants.

It is planned that other utilities not participating in the original load research study group will be able to have reasonable access to the interval data information (again assuming no unresolvable legal or licensing barriers on sharing data exist).

After the rate submission is completed, and if allowed by the distribution license with respect to the release of customer information, the load research database could be released for future load research and analysis.

### Subsequent Use of Load Data

The working group has focused its attention on collection of load data, which requires an early decision by the Board and early action by utilities. A case study of a specific LDC (Brampton Hydro) can be undertaken to confirm how the provincial load data can be used

to generate utility-specific, weather-normalized load shapes for use in the cost allocation studies.

Note if most LDCs in the Province chose to have their load data analyzed by the same supplier (e.g. Hydro One), then it is anticipated a bottleneck may occur. For this and other reasons, the group suggests that the Board consider receiving the cost allocation studies on a staggered basis during the later part of 2005 and early 2006.

### **C) Suggestions On Organizing Remainder Of Cost Allocation Consultations**

The group discussed how to best organize the future phases of the cost allocation consultations.

#### *Remaining Issues*

When working group wishes to resume work in September. Examples of policy and data issues to be discussed include:

- The group has commenced, but not concluded, examining what non-load data information should be collected commencing January 1, 2004.
- While the group had carefully examined various allocation methods, the group's examination of categorization methods remained at a preliminary level.
  - For instance, the group has not yet worked through all the various adjustments the literature suggest should be made to a minimum system analysis; nor had the group worked through a zero intercept example.

#### *Technical Assistance*

The group requests the Board retain a neutral technical facilitator to assist in explaining the details of the various adjustments needed to the minimum system approach (it was also asked if there were versions of the zero intercept approach that were easier to use).

#### *CoS Case Studies Recommended*

It was pointed out that in prior consultations, numerical case studies had been utilized successfully. There was very strong support in the present working group on the expected benefits of good cost of service case studies. Moreover, case studies would provide validation to the proposed CoS methodology.

#### *New Late Fall 2003 Decision Point*

If the Board wanted to direct LDCs to collect additional financial data as of January 1, 2004, for purposes of the cost allocation studies to be filed in 2005 for use in setting 2006 rates, then the group recommends the *Board advise LDCs sometime in the late Fall of*

2003 of any new non-load data information to be collected. The group suggests the consultations be planned with this time line in mind. The group believed the case studies would greatly assist in the process of determining if new information was needed.

## **D) Group's Views On Other Cost Of Service Issues**

The group wishes to issue a second Report dealing with other cost of service issues, such as any additional non-load data to be collected. The following topics were discussed.

### *1) Functionalization*

The group examined a draft summary of earlier discussions on functionalization. The group agreed with the details of the discussion.

### *Long Term Timing Issues*

Important timing questions were raised in this session after an English-language summary of the recent Hydro Quebec decision was reviewed. It appeared the Quebec regulator ordered the utility to file another CoS in the future based on greater subfunctionalization.

The group questioned what would happen in Ontario if the Board happened to order greater subfunctionalization in the expected 2004 generic hearing. If new data was required to be collected but was not readily available, then as a practical matter the Board's decision might not be implemented until the next CoS filings were due, potentially as late as 3<sup>rd</sup> generation PBR.

In light of this, it was debated whether the evolution of cost allocation (and rate design) in Ontario should be viewed as longer term process. One view, which was strongly supported, was to proceed on the basis of present accounting information, especially since the system of accounts had been recently updated, and leave major changes for later (e.g. as part of a potential mid-plan review of 2<sup>nd</sup> Generation PBR). Another view was that the requested case studies could allow stakeholders to see whether greater subfunctionalization is required (and if the Board issued further directions in the Fall of 2003, any extra accounting data needed could be gathered for use in the upcoming CoS studies).

### *2) Recommendations re Demand Allocation Method(s)<sup>1</sup>*

The group had a final discussion on what should be the recommended default demand allocation methods (because 12 months of interval data will be collected, the data to be collected will support the use of either 1NCP or 12NCP). A general consensus was eventually reached on the following recommendations [Editor's note: one group member later dissented]:

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<sup>1</sup>Note this topic was one of the seven items listed on the original issues list.

- 1NCP be the “default” demand allocator for the CoS filings.
- LDCs be given the option of using 1CP, 2NCP, 3NCP, 4NCP or 12NCP, if they could explain why it was more appropriate in the specifics of their situation.
- Any utility wishing to make use of one of the optional methods must run its CoS results twice, once with 1NCP and a second time with the optional demand allocator preferred.

The group reviewed the following additional comments by Professor Mountain (an earlier guest speaker) suggesting why, under present circumstances, an Ontario LDC seriously consider selecting 12 NCP as its preferred demand allocator: “If your rate design is based on 12 non-coincident peaks, the implications of having a bad forecast of any one non-coincident peak is not significant compared with the forecast of one annual non-coincident or coincident peak. It is much more difficult to forecast with any degree of accuracy one annual peak whether it is non-coincident or coincident peak. One of the principle concerns of rate design is to have a design that will on average recover costs. Particularly, if we base the forecast on load research data corresponding to only one year of monitoring, we will hard pressed to have a good forecast of one peak in the year.”

### *3) Further Comments on Categorization Methods*

The group had hoped to examine all potential data issues arising from alternative categorization methods, but time constraints, and the technical difficulty of the material, made this goal unrealizable. The group therefore concluded with some further preliminary discussion on categorization, and further discussion of this general topic is planned for the Fall.

#### *i) Definition of Customer Costs*

It was noted the APPA’s *Manual Retail Rate Design for Publicly Owned Electric Systems* (1992) defined “Customer Costs” as follows: “Costs that are related to and vary with the number of customers, such as meters, meter reading, service equipment, and a portion of distribution.”

#### *ii) Basic Customer Costs*

The group understood what is referred to as the “basic customer costs” method of categorization in American literature refers to the first part of the above definition (“meters, meter reading, service equipment”). Under this view, the basic customer costs acts as a floor or minimum for the fixed customer charge (although it was previously noted that in some U.S. states, basic customer costs have been used to set a maximum fixed customer charge; the merits of this alternative approach will also be considered later).

The group previously heard that the definition of basic customer costs varies between jurisdictions. The following “classic” U.S. articles were obtained (and a draft presentation circulated):

- “Customer Costs”, Catalano, Public Utilities Fortnightly, December 17 1981
- “The Customer Component of Utility Costs”, Fleishmann, Public Utilities Fortnightly, March 2 1972.

Another issue flagged is that Ontario LDCs may not be collecting, at present, sufficient information to allow accurate calculation of the basic customer costs.

*iii) Alternative methods to calculate the portion of distribution charges to add to customer costs*

The group agreed with the view articulated by some experts that there is no single agreed-upon method by which to calculate what amount of distribution costs should be added to customer costs, as per the above APPA definition.

*iv) Zero Intercept Method*

It was pointed out that several sources believed this method was more accurate than the minimum size method (some group members wondered if other experts thought otherwise).

- Page IX-9, APPA Manual *Cost of Service Procedures for Public Power Systems Re Louisville Gas and Electric Company*, 204 PUR4th 196 (2000).<sup>2</sup>

To undertake a zero intercept analysis, it was understood that detailed financial data was required (which may prove difficult for some LDCs, to be discussed further this Fall), as well as engineering data. The group noted that the zero intercept method has been used by a Canadian utility - see June 2002 decision involving Newfoundland & Labrador Hydro, which commented at page 109:

“[The utility’s expert witness] does acknowledge that the result of using the zero intercept methodology is a somewhat lower proportionate classification to the customer component than generally used by Canadian utilities.”

*Note re Further NARUC Cost Allocation Manual*

A copy was recently obtained of the first edition (1973) of the NARUC Cost Allocation Manual, which focuses on how to do an average cost of service study (the type this working group is recommending). The group will be asked to respond to the following points made there:

- “[The zero intercept method] requires considerably more data and calculation than

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<sup>2</sup>An intervenor in that case also asserted that use of the minimum system, instead of the preferred zero intercept method, “would significantly assign greater costs to the residential class and away from other classes”.

does the minimum-size method, but it may be more accurate for most cases, although the difference may be relatively small.” (Page 56)

- “The minimum-size method requires greater application of judgment. Previous studies tend to show that it [the minimum-size method] generally produces a larger customer component than does the zero-intercept method.” (Page 59)
- “When data for its calculation can be obtained, the minimum-intercept method is recommended for use over the minimum-size method.” (Page 56)

#### *iv) Minimum System Method(s)*

A written presentation was circulated which clarified the difference between the “bare-bones” minimum system and the utility-specific minimum system.

- The bare-bones methodology assumes the absolute minimum size of equipment to supply the 100watts per customer, regardless of fact that this might result in wire sizes and transformers that are neither applicable nor in standard use at LDCs in Ontario.
- The utility-specific minimum system approach defaults to using the standard equipment selections that were in use for that LDC. As an example, the smallest size transformer stocked by a utility might be 10k VA, and the standard pole in use might be a 35' class 4. These would then be the default selections for the minimum system design, instead of any values that might be calculated (and not likely to exist).

An issue identified for future discussion was whether any guidelines should be issued by the Board if it were to be expected that 90plus LDCs could consistently calculate their own minimum systems.

How to do a “vintage” adjustment, mentioned in the Ontario Hydro reports from the 1980's, also remained to be clarified. (Note the group has access to an English language expert's report filed in the Hydro Quebec decision which appears to address the issue.)

Another important technical issue flagged for subsequent discussion was how to address “double-counting”. One solution was identified at page 18 of the MEA's *Generic Cost of Service Analysis and Findings* (December, 1988):

“The group NCP was adjusted to recognize the peak load carrying capability (PLCC) of a minimum system when applied to poles and conductors. No PLCC adjustment was made to the group NCP in the allocation of substation costs.

To quantify the PLCC credit, an engineering analysis was undertaken to determine the peak load carrying capability of the minimum-sized conductor

selected for the strata. The PLCC for each strata reflected the customer density, material specification procedures, and estimated customer diversities for the specific type and size of utility reviewed. For this study, it was found that a PLCC credit of .25 KW/customer for all strata was appropriate if the minimum distribution system is assumed to be conductor constrained. A larger credit would have been appropriate if the minimum system was transformer constrained.

The resultant PLCC per customer for the strata being analyzed was multiplied by each customer class's actual number of customers. The product of this calculation was deducted from each class's group and individual NCP allocation factor determinants before calculating the appropriate allocation factor to avoid 'double charging' to the distribution system's demand component."

The group noted the English language summary of the recent Hydro Quebec stated the regulator directed the distributor to take into account a demand of 1 kW per customer on its minimum size network for the allocation costs between the demand and fixed charge component. The group believes this adjustment relates to the same issues identified above, and the numerical value adopted in Quebec would lead to a significantly lowered fixed charge. Given the categorization method(s) adopted will generate the initial fixed cost calculation, the importance to all stakeholders of accuracy was stressed (subject to the administrative advantages of having a common default).

#### *v) Modified Minimum System Method*

It was noted that the question of whether the categorization method adopted should recognize energy was debated in many other jurisdictions. For instance, an expert's report filed on behalf of the regulator in a case involving Newfoundland Power Company commented: "It would be reasonable to classify a portion of the distribution system as energy-related simply because, although sized to meet local peaks, the facilities are clearly used to meet both energy and demand requirements."

The group noted that considerable empirical work was undertaken in Ontario in the 1980's on this issue, which led to the development of Ontario's innovative "modified" minimum system approach which explicitly recognizes the role of energy consumption in assigning costs (not traditionally done in U.S. texts, such as the NARUC Manual).

Ontario Hydro report R-85-10 (Guelph mock-up) commented at page 35:

"Modification to the minimum system methodology involves the addition of 'Energy' to the two categories of 'Demand' and 'Customer' normally used in traditional cost-of-service studies. The rationale for adding energy as a category is to include the effect of energy on ongoing costs of operation and

maintenance of distribution facilities. To investigate this a study “Influences of Feeder Characteristics on Performance Using Regression Analysis “ - Sept., 1984, was undertaken, using 1982 as latest year, to examine the influence of feeder load characteristics on the failure rate of these feeders.”

The MEA’s Generic Cost of Service Analysis and Findings, December 1988, summarized other Ontario work on this issue:

“The AMEU committee findings recommended the use of the modified minimum system approach with the residual demand component split between demand and energy on a two-thirds to one-third ratio, respectively. The modified system method appeared to represent the most viable option for the proper categorization and allocation of distribution facilities. The AMEU committee also concluded this method appeared to not impose undue change on any particular customer group’s revenue requirement.”

It should be noted the 1988-2000 MEA Unbundling Task Force recommended continued use of the modified system results as the default categorization method. (Note the original MEA 1985 study has been recently located and will be considered by the working group.)

It was this group’s present understanding that adoption of a traditional minimum system method in place of the modified minimum system would not change the fixed variable split, but would change the balance between various rate classes if the energy allocator by class is different than the deemed allocator by class.

#### *vi) Default Categorization Option*

An issue identified for later discussion was the merits of common categorization figures. Given utilities were committing to the expense of new load data, which is a financial pressure for the smaller LDCs, developing an option which would allow use of an inexpensive default approach to categorization was felt to be important.

The results of the 1980's modified minimum system research was one potential source of common figures. Alternatively, some version of a (regular) minimum system results could be used as defaults for the filings - for instance, a 50-50 split between demand and customer costs is suggested as a reasonable approximation for smaller utilities in the APPA’s Cost Allocation Manual (at page IX-9).

Whether the largest distributors should make use of any default figures was a further issue.

#### *4) Final Comments on Link between Cost Allocation and Rate Design*

It was pointed out that the Ontario Hydro CoS methodology reports from the 1980's contained explicit references to rate design goals.

- The review of the modified minimum system approach in Report R-85-13 (see Appendix 7) discusses how the calculation of the minimum system should be adjusted depending upon what rate design objective was pursued in respect of using the fixed customer charge as an “access” charge.

The present group, however, preferred to try to distinguish between the cost allocation and rate design stage. [Ontario stakeholders interested in studying how the results of an embedded/average cost allocation study are used to set rates are referred to the APPA publication *Retail Rate Design For Publicly Owned Electric Systems*, available by calling 202 467 2900.]

As a practical matter, two of the key issues the present group examined involved substantive overlap between cost allocation and rate design:

i) The load sampling program to be commenced soon could influence the future introduction of rate classes. In specific, unless the appropriate load data were collected at this time, no new rate classes could be introduced in the future with proper cost causality backing. In the wrap-up session, the group remained comfortable with this conclusion (which was the same basic view held by the 1998-2000 MEA Task Force).

ii) The group also reviewed newly-obtained U.S. material which pointed out that the degree of subfunctionalization would impact rate design options. The APPA manual *Cost of Service Procedures for Public Power Systems* stated (at page VIII-2): “The National Energy Act requests cost of service information for service at different levels of the system. Subfunctionalization of costs by voltage levels will result in cost information useful in rate design.”

It was questioned whether the second point would be raised in Ontario. An intervenor’s expert report in the Hydro Quebec hearing had argued “HQD should be encouraged to track more accurately the cost of low voltage versus medium voltage facilities so to not have to rely on its minimum system analysis to separate the cost of the two Distribution sub-functions in its costs allocation study”.

Overall, the importance of trying to avoid making decisions which would preclude the subsequent rate design working group from having much of substance to discuss was stressed.

Some final thoughts were advanced on the expected outcome of the cost allocation studies compared to the policy objectives enunciated in the Badali Report. In the long term, the group suspected updated cost of allocation studies could reduce some of the variability in fixed charges across the Province. However, some variability would likely remain, due to underlying differences in LDC cost structures. It was also pointed out that some of the present variability in fixed customer charges were due to mitigation decisions made in prior rate cases.

Finally, group members stressed it may be misleading to compare LDCs solely on the basis

of the their fixed customer charge, since the variable charge may be lower.

#### *5) Circumstances of smaller LDCs*

It was suggested that under the provincial load data initiative, the smaller LDCs would pay higher per-customer amounts for their updated load data (although they would still save considerable compared to going alone). The organizers of the provincial load data initiative were previously aware of such concerns and announced they would endeavour to address them.

A spreadsheet was examined and it was suggested small LDCs consider if the Z factor rules could apply to the expense of their CoS studies.

In earlier discussions, the idea of allowing smaller LDCs to use non-statistically verifiable load data was raised. The conclusion of the group was not to follow that route for a variety of reasons, for example the customers of the LDCs involved might feel they were treated inferior.

While the smaller LDC canvassed did not want to ask for exemptions from any uniform load data rules, they did hope the total cost of regulatory compliance would remain reasonable. Board approval of default categorization figures was regarded as important in this regard.

#### *6) Sensitivity Analyses*

It was noted a U.S. article (“Embedded Cost-of-Service Studies - Issues in the Wake of PURPA”, Austin and Stutz) had suggested the following:

“[I]t is quite reasonable and cost-effective to perform multiple runs of computerized cost-of-service studies. Such studies can easily address the cost implications of employing or not employing the minimum system technique, and allow relatively quick assessment of the roles of the CP and AED based allocators.”

A draft “sensitivity” table was presented which summarized:

a) Issues which it was expected could significantly impact allocation between classes, such as:

- Demand allocator (1NCP v. 12NCP etc.).
- Weather normalization method (average of extremes v extreme).
- Categorization method (use of modified minimum system; how to adjust for load carrying capability of minimum system).
- Determination of weighted customer allocators (e.g. use of expert’s opinion v. guidelines).

b) Issues which are expected to influence the initial value of the fixed charge:

- Categorization method used:
  - zero-intercept v. minimum system could have some impact; the choice of basic customer method as floor v. maximum would have the largest impact.

c) Matters which may prove technically difficult for every LDC in Province to successfully complete:

- May be hard for some LDCs to collect data necessary to do a zero intercept or minimum system analysis (the later calculation also required several adjustments).
- The new system of accounts adopted by Ontario LDCs may not allow as much subfunctionalization (e.g. voltage detail, primary v. secondary) as may be desirable in the long run.

### *7) Goals of Cost Allocation Studies*

At the first few meetings, the group has established some tentative policy goals. A final discussion was held to write up material for the second Report.

#### *a) Fairness between rates classes - accepted*

The group confirmed that the key goal of the cost allocation study was to ensure fairness between rate classes. This was interpreted as each rate classification paying its own way, that is, one grouping would not subsidize another.

- The group had also discussed that there is commonly a “margin of error” in cost allocation studies.
- The group will later examine the rate at which any cross-subsidization should be reduced.
- The group used a simple accounting definition of cross-subsidization (ratio of revenue to allocated costs per class), which the group understands is followed by other Canadian regulators. Views of cross-subsidization based on economic theory were not considered by this group.

#### *b) Fairness within a rate class - deferred*

The group had previously noted that the Ontario Hydro rural system cost of service mock up from the 1980's had raised the question of fairness within a rates class. The group understand the question to revolve around the fair balance between the fixed versus variable split within a rate class.

By way of background, during the consultations it was noted:

- One of the steps in the cost allocation process (categorization, by means of zero intercept, minimum system, modified minimum system, or basic customer charge) establishes one of the components that at the rate design stage is used to calculate the fixed monthly charge.
- There was no single generally preferred categorization method, and each could lead to differing initial fixed cost calculations.
- It is a common practice that the prima facie amount of the fixed charge calculated by the cost allocation study is reduced significantly at the rate design stage, as part of mitigating customer impacts.

After discussing the issue, the present group was of the view that fairness within a class is fundamentally a rate design question.<sup>3</sup>

*c) "Fairness" in applying cost causation - examples accepted*

Several examples<sup>4</sup> were discussed to illustrate the fine points of applying the concepts of cost causality in practice:

- For instance, if a system were originally built to serve customer X, but now serves Y, then an argument exists that Y should pay for the benefits received even though, from a historical point of view, Y did not cause the cost to be incurred.

The group agreed with the above example, but debated how best to interpret it. Some thought a "benefits" principle (or what Bonbright terms "value-of-service considerations" - see page 497 2nd Edition) was being used to override strict cost causality; but others thought the concept of cost causality was broad enough to include the benefits principle (some believed this would have minimal practical impact though).

The group considered, but ultimately rejected so as to not give others the impression that CoS results are subjective, the views expressed in Appendix A of Ontario Hydro Report R-85-13 that "cost allocations are a way of arriving at a 'fair' price-even if cause-and-effect logic may be hard to find".

*d) Efficiency as a policy goal - deferred*

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<sup>3</sup>Note the group had earlier considered a U.S. decision, *Re Gulf Power Company*, 218 PUR4th 205, which tended to oppose a strong distinction between cost allocation and rate design.

<sup>4</sup>Fairness arguments were also raised during the discussion of alternative demand allocators (CP v. NCP etc.). See Ontario Hydro Report RS-92-6 for illustrations.

The group had previously decided the role of efficiency as a goal was best deferred for discussions at the rate design stage. (Some also thought this was a commodity pricing issue with limited relevance for distribution rates.)

In the present meeting, the group briefly noted arguments advanced by the regulator's expert witness in a Nova Scotia Power Incorporated proceeding (Dr. Stutz), and in a Newfoundland Power Company proceeding (Dr. Wilson), that both seemed to suggest lower fixed customer charges promote better price signals and hence efficiency.

But the group remained of the view that such issues were best addressed at the rate design stage and therefore reiterated the view that efficiency was not a formal goal of the cost allocation process.

*e) Rate stability - rejected now as goal of cost allocation stage*

The group has initially accepted rate stability as a secondary goal of the cost allocation process. But on various issues during the course of the consultations, group members split on this point.

The whole issue was reexamined at the wrap-up meeting. Some suggested that if there were two ways to do a certain step in a cost allocation study and if each were equally valid from a technical point of view, rates stability could be used as a tie breaker. It was also pointed out that rates stability was mentioned in earlier studies in Ontario (e.g. during the MEA discussions in the 1980's that led to the adoption of the modified minimum system method of categorization for CoS purposes).

After considering various compromise positions, the group ultimately decided to reject its earlier position (still reflected in prior meeting notes) and now view rates stability as a goal to be pursued at the rate design, rather than cost allocation, stage.

*f) Stability of Cost Allocation results - accepted*

The group decided stability of cost allocation results is an appropriate goal for the forthcoming Ontario cost allocation studies.

By way of illustration, if a proposed cost allocation methodology would lead to widely differing results in various years, the technique should be rejected as unstable. It was also suggested that stability in cost allocation results would in itself contribute to stability in final rates.

*g) Average v. Marginal Cost*

The group had earlier decided to recommend use of an average cost approach to cost allocation. The write up of that section was pending.

Examples from former Ontario Hydro policies (during a period in which rates were still bundled) illustrated how it was still possible to introduce some marginal cost concepts (e.g. TOU rates) at the rate design stage, even if the cost allocation had been completed using an average cost approach.

The group discussed that the starting point of the present variable component in residential rates of LDCs appears to be based on the results of an Ontario Hydro study (Report RS-92-18) on the average incremental capital expenditure on distribution facilities. It was discussed whether “incremental cost” as determined from use of historical cost data actually corresponds to forward-looking short run or long run marginal cost, as economists use those terms.

### *8) Weather Adjustments*

Due to time constraints, no time was set aside at this meeting for a final discussion on how to weather-adjust load data. At earlier meetings, the group had debated the merits of two different ways to adjust weather and the tentative conclusion was to favour use of an average of extreme days.

At the present meeting, it was noted that an English language expert’s report filed in the recent Hydro Quebec case (circulated to group members) suggested Hydro Quebec was weather adjusting to average weather. It was also commented that one of the major Ontario natural gas distributors appears to have done the same in the past, for some purposes (note the working group has not had the time to carefully consider OEB cost of service rulings re natural gas distributors).

In light of the above, the forthcoming write up of this section would list three options. An issue flagged for later discussion was whether one method was better suited for some purposes than the other (for example, should the revenue forecast best be normalized to expected average weather?).

The working group had intended to ask an earlier guest (Professor Dean Mountain) his views on weather normalization, but time precluded reaching the topic. Professor Mountain kindly forwarded to the working group his views in writing:

#### *Should large utilities weather normalize and small utilities not weather normalize?*

“A major purpose of weather normalization is to have the recommended rate structure be correct on average over the next 5 to 10 years be equitable and recover costs. Not weather normalizing the load could mean that you have designed your rates to an extreme year and on average your new rate structure would not be equitable and not recover costs. Here, small utilities would be particularly vulnerable. Their load tends to be less diversified and have lower load factors, particularly in extreme years. By basing their rate design on an unadjusted year could have enormous rate impact on some rate classes.”

### *9) Purpose of Distribution System*

Various major issues in the consultations (e.g. categorization methods, weather normalization) raised the issue of for what purpose(s) a distribution system is designed. Professor Mountain's further written comments also addressed this question:

"Besides meeting the peak demand, the distribution system is also designed to deliver energy and to have a certain reliability throughout the year. A utility does not construct a distribution system to only meet one annual peak and not worry about the rest of the year. Certainly, a utility's investment in equipment would be much different than it is now, if the utility was just worried about the annual peak and not worry about whether it was reliable to deliver energy and peak demands in other months. There are many examples one could construct to illustrate this. Consider a utility only serving customers only demanding electricity in July with no kilowatt-hour consumption in the rest of the year. The utility's investment in distribution facilities would be very different from a utility with the same demand in July and consumption in the rest of the year, albeit with monthly peak demands in other months less than the peak in July."

### *10) Which year's financial data to use in applications?*

A group member had asked if a historical or future test year would be used in the upcoming filings. The question was deferred for future discussion, as per the original schedule.

## **Attendance**

Bluewater Power - Kathy Gadsby  
Brantford Power - Heather Wyatt  
CNPI - Doug Bradbury  
Guelph - Jim Fallis  
Hamilton Hydro - Terry Karp  
Hydro One - Mike Roger, Stanley But  
London Hydro - Dave Williamson  
Upper Canada Alliance - Jim Richardson, Dave Weir  
Oakville - Gary Parent  
Ottawa - Lynne Anderson  
Toronto - Anthony Lam  
Thunder Bay Hydro - Cynthia Domjancic  
Veridian - Laurie Stickwood  
Whitby Hydro - Ramona Abi-Rashed

AMPCO - Ken Snelson  
Bruce Bacon  
ECMI - Roger White, Andy Bateman  
EDA - Maurice Tucci  
FOCA - John McGee  
Barker, Dunn & Rossi - Paula Zarnett  
RCS - Peter Ioannou  
Chris Amos  
Bob Mason

Guest: Enersource

Board Staff:  
John Vrantsidis  
Neil Yeung