The Cost Allocation Working Group

First Report

Load Data Collection

September 23, 2003

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EXECUTIVE SUMMARY

The Cost Allocation Working Group is pleased to present its first Report. The main focus of this Report is on the collection of load data for use in future cost allocation studies to be filed by each Ontario electricity distributor/local distribution company ("LDC").

The three major steps in a complete cost of service study consist of functionalization, classification, and allocation. Load data is a key input in the allocation stage. In specific, it is used to determine non-coincident or coincident demand peak by rate class, which in turn is used when allocating demand-related distributions costs between rate classes.

Load Data Questions Requiring Early Resolution

Some of the matters the Working Group were asked to examine in the Board's preliminary issues lists (see Appendix I) are time sensitive, and the Working Group suggests guidance be issued on the following as soon as practicable.

Issue 1) What type of load data should be collected?

To provide the full range of data that may be needed when subsequently completing the cost allocation studies, the Working Group recommends that interval load data start to be collected.

Issue 2) Is additional metering needed? Are there any practical constraints if additional metering is required?

Installation of a considerable number of interval sample meters will be needed to collect the load data required to produce an acceptable level of confidence.

The Working Group understands that acquiring appropriate meters can take up to 10 weeks, meter installation up to an additional 8 weeks, and meter testing a further 4 weeks. Based on these time lines, the Working Group's realistic estimate is that load data collection cannot generally commence until around five months after distributors receive the Board's approval on the collection methods and sampling techniques proposed. Note this implies a common January 1, 2004 load data collection start date is not feasible.

The Working Group would ask the Board to consider each recommendation as part of a total package. Acceptance of the joint data collection option proposed will contribute towards starting load data research in a timely manner. If each distributor were required to collect statistically-reliable load data on its own, it is believed the technical complexity will lead to delays.

The Working Group also looked at financial constraints. The total "out-of-pocket" cost of new load data collection includes interval meter acquisition, meter installation, and meter reading. Distributors may also incur costs for professional advice to design and implement their load research programs. Overall, the Group believes it would be uneconomic to have each Ontario distributor undertake its own full blown load research program. The leading North American reference supports this view. Joint collection of load data (recommended below and currently implemented in several U.S. states) will greatly reduce the "out-of-pocket" metering and sample design costs, without sacrificing reliability of results. This represents a "win-win" situation for all Ontario stakeholders.

Issue 3) For what length of time should the load data be collected?

The Working Group recommends, as is standard practice, that at least 12 months of load data be collected.

Issue 4) In order to ensure reliability of the load data gathered, what sampling methodologies are appropriate?

The Working Group recommends that any of the statistically-verifiable sampling methodologies discussed in the leading North American reference in the field (AEIC's <u>Load Research Manual</u>, 2nd Edition) be accepted for use in Ontario.
The Group further recommends that each electricity distributor in the Province be required to produce an LDC-specific load profile that meets the standard North American target accuracy of plus or minus 10% at 90% confidence. Use of such high quality data is considered to be important when rates may be impacted.

The Group is aware that non-statistically rigorous approaches to load data collection approaches exist. These are <u>not</u> emphasized in the present Report. In effect, it is suggested all Ontario distributors move towards North American best practices. To ensure such high quality load data is collected in a cost-effective manner, the acceptance of the joint data collection option is considered key.

The Working Group is sensitive to the higher per customer costs to be imposed upon the smaller distributors as a result of its recommendation that each LDC use statistically-reliable load data. But the Working Group believes, as a matter of principle, in the importance of having all the cost allocation studies prepared with consistent high quality load data. It should be recognized the Working Group has endeavoured to balance its conclusions by 1) suggesting the Board approve a joint load data collection option that will allow distributors to meet the PURPA targets in a cost-effective manner, and 2) recommending future consultations develop a cost-effective common categorization method.

Issue 5) The Distribution Rate Handbook presently recommends "achieving economies where possible through joint development of load data" (para. 1.4). How can joint collection of load data be best implemented?

The facts examined by the Working Group confirm a statistically-designed, Province-wide sampling program is the lowest cost method for all LDCs to gather new reliable load data (e.g. the installation of thousands of interval meters can be avoided). Further analysis will be required to convert the raw Province-wide load data into LDC-specific load profiles that meet North American accuracy targets. Existing expertise exists in the Province to undertake the second step in a cost-effective manner.

Appendix K to the Report sets out a specific proposal advanced by forty-plus distributors serving about 80% of the customers in the Province. This group of LDCs (the "Ontario Load Data Research Group") is geographically diverse and serves both urban and rural customers. To provide independent expert advice, a local academic was retained with experience in how the former Ontario Hydro designed its Province–wide load research programs.

The Working Group recommends that the current rate structure is a sound basis for starting load data research. For example, the Ontario Load Data Research Group proposes:

- About 600 residential class interval sample meters are to be installed (to be used along with 100 currently in place). Seasonal residential customers will be included in this sample. New meters will be randomly installed, at locales recommended by expert advice, using a stratified approach that reduces the numbers of meters required to obtain reliable results.

- Load data for the GS>50 kW classification will be obtained from amongst the several thousand meters currently installed in this range by Research Group members.

- The GS<50 kW class will be partially estimated as a residual. A residual estimate of a class has been used in earlier load data research studies in Ontario and elsewhere. The Ontario Load Data Research Group has received a sophisticated technical defence of its use in respect of the heterogeneous GS<50 kW class. But the Research Group also has access to a few hundred interval meters in this classification, which will provide new data to supplement the estimate. (The Working Group asks the Board to decide if any distributor in the Province can make use of a pure residual estimate, or should all distributors be required to develop load profiles based upon using some new load data from <u>each</u> major rate class, as planned by the Ontario Load Data Research Group.)

- It is assumed all Large Users and Intermediate Users are individually metered already (the latter should be confirmed by affected LDCs).

The Professor expert retained by the Ontario Load Data Research Group is also knowledgeable in employing specialized techniques (such as Bayesian statistics) to validly make use of past Ontario load data. This will be investigated further by the LDCs funding that research, and thus the present Report will contain no recommendations as to how much of the considerable past Ontario load data research can be reasonably used for present purposes.

The Working Group would caution that mandating each distributor to collect its own load data separately will not improve the accuracy of the final results but would unnecessarily add considerably to industry costs. The co-operative load data collection program suggested is currently being followed in several U.S. states, and such an approach has been recommended in past expert studies. The Ontario Load Data Research group is willing to proceed with a case study to validate its methodology.

Issue 6) Relationship between load data to be collected and rate classifications.

As suggested in past Board correspondence, the Working Group confirmed there are interrelationships between the number of rate classifications and the design of the load data sampling program.

The Group recommends that every distributor examine each of its current, or planned, rate classifications and decide 1) is load data technically required, and 2) if so, how will the load data be obtained. Thus, aside from some special circumstances discussed below, distributors should at the moment be considering the load data needs for each of the rate classifications to be included in their 2006 rates applications.

The Report considers the potential load data needs for every Ontario distribution rate classification. The Working Group recommends further discussion of some technical points (for instance, confirmation of what additional data would be needed to support the introduction of voltage-based rates for large users; also, the potential load data needs for "back-up" rates were unknown).

While the cost allocation studies to be filed should include updated, statistically-reliable load data for most rate classes, the Working Group believes that technically not every rate classification requires its own load data. In particular:

- The profiles of certain uses (street lighting, sentinel lights, and unmetered scattered load) are commonly "deemed".

- The Working Group believes that a few rate classifications do not require separate load data (such as low density rates or polyphase rates). Note that separate cost data may still be required for such classes.

The Working Group respectfully disagrees with the comments in the Distribution Rates Handbook as to when no data may be required (e.g. intermediate users). It is recommended the Board consider stakeholder input, and then issue directions on which rate classifications will not require full supporting load and financial data.

Other issues examined

The Working Group was asked to assess the merits of an average versus a marginal cost approach to undertaking the upcoming cost allocation studies. The Group recommends use of an average ("embedded") cost approach (as has been followed by Ontario natural gas distributors).

The original issues list also asked the Working Group to examine the merits of alternative demand allocators (non-coincident peak v. coincident peak), which it did at length. A majority of the Group has agreed to recommend use of 1NCP as the default demand allocator (determination of both class and customer NCP is recommended), but to also give an LDC the option of choosing from an approved list of alternative methods (CP, 2NCP, 3NCP, 4NCP or 12NCP) where it can explain why the latter better suits its circumstances (in such cases, it is recommended the LDC calculate its results twice - using both its chosen alternative method and the 1NCP default - to provide a sensitivity analysis).

It should be noted that if the recommendation to collect 12 months of interval load data is accepted, then the resulting load data will be comprehensive enough to support use of a variety of demand allocators. Therefore the Board need not make a decision on the preferred demand allocator at this time (a dissenting Group member preferred this approach over accepting 1NCP as a default).

Because there are few Ontario utilities with the software and expertise to process the load data to be collected into LDC-specific load profiles, this analysis stage may present a bottleneck. To avoid this, it is recommended that distributors be allowed to file their cost allocation studies on a staggered basis starting sometime in July of 2005. Note that if the collection of 12 months of load data starts too late in 2004, it could delay the filing of the rate applications in 2005.

The Working Group added the issue of weather-normalizing load data to the agenda, and the Group's preliminary views on the topic are included. Note if the Board mandates the same, the (one-time) total cost of new load data will increase.

The Working Group recommends that the additional individual customer metering to be installed for load data research purposes be within plus/minus 1% accuracy. A few Group members dissented and believed less statistically-accurate methods are justifiable.

The Working Group recommends distributors follow an industry generally-accepted procedure for data validation and editing.

How the load data research is organized in the next few months will have some future impact on rate design options for which full data will be available. It is expected the Province-wide sampling program will be broad enough to provide load data for a future revaluation of the 50 kW General Service boundary, if so desired. It is requested that the Board indicate if the load data from the thousands of General Service meters available should be organized to potentially support the introduction of a specific new General Service subclass.

The Working Group understood it was to focus on the collection of load data for purposes of undertaking cost allocation studies. It will be left to others to examine the merits of collecting further load data for other potential uses (for example, as part of a comprehensive Demand-Side Management plan).

The Working Group suggests that some thought be given as to how best to organize the future conduct of load data research in the Province, as U.S. materials indicate accurate updated load data is an asset with many potential valuable uses (e.g. enhanced distribution system planning).The establishment of an Ontario Centre of Excellence for load research is recommended.

The Working Group recommends that cost allocation case studies be undertaken. It is believed these will facilitate technical discussions and provide feedback on the practicality of the policy options being studied. The Working Group also believes that actual case study examples will prove helpful when the OEB later develops filing guidelines. As well, LDCs will benefit from practical examples when preparing their own submissions.

The Working Group recommends the Board advise the industry on a timely basis (such as by November 2003) if any additional non-load data must be collected commencing January 1, 2004.

1. BACKGROUND

Prior Board Directions

In its decision RP-1999-0034, the Board indicated that "utilities will be required to undertake cost allocation studies to better align rates among customer classes with cost causation in second generation PBR" (paragraph 2.1.13).

The Electricity Distribution Rate Handbook ("DRH"), issued in March 2000, repeated the requirement to prepare cost allocation studies (see paragraph 1.4) and added a specific reference to updated load profiles:

> "Prior to the implementation of 2nd generation PBR the Board will require utilities to develop allocation studies that reflect: (1) the new structure of the industry, (2) *current load profiles of the various rate groups* and (3) a review of the method of allocating distribution cost to rate classes." (italics added)

The DRH contained the following additional comment (see paragraph 1.4) regarding load data collection:

> "The Board strongly encourages utilities to jointly sponsor these studies, achieving economies where possible through *joint development of load data*." (italics added)

On October 28, 2002, the Board issued a letter to all electricity distributors ("LDCs"), and other registered parties to the RP-1999-0034 and RP-2000-0069 proceedings, attaching a preliminary issues list for the upcoming cost allocation consultations (copy attached as Appendix I).

That letter also indicated: "In the upcoming discussions, stakeholders are urged to consider what cost allocation methodologies are appropriate and practical, given the Ontario context and the planned timelines identified".

The first meeting of the Cost Allocation Working Group occurred on November 7, 2002. The meetings were temporarily suspended following the introduction of Bill 210. The meetings resumed on March 27, 2003. The last meeting of the initial phase of the cost allocation consultations took place on June 26, 2003. After that, the present Report was prepared.

Current overall project time lines

Based on the time lines set out in the Board's most recent correspondence, the Working Group understood the key target dates are as follows:

- By early 2004, raw load data is to start being collected.
- In the latter part of 2004, the Board plans to hold a generic hearing examining, among other things, cost allocation principles and policies.
- In 2005 distributors are to file their completed cost allocation studies (with demand allocators reflecting updated LDC class load profiles).
- The cost allocation studies will be used to help set 2006 rates (that is, "going-in rates" for the next generation performance incentive plan).

Note on terminology

In RP1999-0034, "cost allocation study" was defined as follows: "Cost allocation studies deal with the allocation of the revenue requirement among customer rate classifications" (see footnote to paragraph 2.1.13). Older references sometime refer to the same concept as a "cost of service study" ("CoS").

Also note that the term "cost allocation" refers to the third of the traditional steps in an embedded cost of service study (discussed further below).

Finally, the terms "LDCs", "distributors" or "utilities" are used interchangeably in this Report.

2. Purpose of Present Report

The original issues list focused primarily[1] on load data collection topics, since these decisions are time sensitive. In particular, in order to start collecting new load data in early 2004, sample meters must be ordered several months before then. To properly place the meters, a statistically-designed sampling program is required. The present Report will focus on these issues. The Working Group hopes for early Board direction on load data collection, so that the industry can proceed with its sampling program as soon as possible, thus ensuring that the resulting cost allocation studies are filed on a timely basis during 2005.

The Working Group decided to also look at other data issues (in specific, non-load data required for the completion of the cost allocation studies). It is expected those matters will be included in a second Report. The Board may wish to give directions in due course on any additional non-load data to be collected for cost allocation purposes.

Formation of Ontario Load Data Research Group

The desire to update load data in an accurate and cost-effective manner led some of the distributors in the working group to explore a cooperative approach. Many distributors in the industry later expressed a desire to join that voluntary group (referred to as the "Ontario Load Data Research Group", and now comprising over 40 LDCs serving the bulk of the electricity customers in the Province).

It should be noted membership in that Research Group is entirely voluntary, and some distributors have declined to become founding members of the Ontario Load Data Research Group.

The body and conclusions of this Report will address general principles applicable to any LDC, or group of LDCs, collecting load data. The specific proposal of the Ontario Load Data Research Group is summarized in Appendix K.

[1] The issues list also asked for the Working Group's recommendations on the merits of an embedded cost of service study versus a marginal cost of service study. The Working Group recommends the former (which is the same methodology used by natural gas distributors in Ontario) and its reasoning is set out in Appendix A.

3. References

As its major reference source, the Group consulted the Load Research Manual (2nd Edition, 2001) published by the Association of Edison Illuminating Companies (the "AEIC" is comprised of various North American electrical utilities). The Working Group understands this is the standard North American reference in the field and has been cited and relied upon by regulators.

The Group wishes to acknowledge, and thank, the generous assistance of the members of AEIC Load Research Committee (which included Canadian utilities such as Hydro Quebec, and Newfoundland and Labrador Hydro) in locating specialized materials, and in informing the present group about other cooperative load research initiatives in North America. Ms. Erin Puryear provided helpful material on the Virginia state cooperative load research program, including presentations on the benefits of updated, accurate load data.

Working Group members were fortunate to locate some technical reports from the former Ontario Hydro, including Load Analysis for Cost of Service Studies Report R & U 79-5 (June 1979).

The Group benefited from guest appearances by two former Ontario Hydro load data researchers, Professor Dean Mountain and Dr. Neil Mather. The Group also heard guest presentations from two meter specialists (Kevin Mills, and later Paul Elliot), and a meter data management specialist (Douglas Bray).

The Working Group should like to thank all of the above for generously offering their time. On behalf of Ontario stakeholders, appreciation is also extended to the volunteers of the present Working Group (listed in Appendix J), who all contributed to the Group's work. This represented a major commitment of time and effort.

Readers wanting further knowledge on the use of load data for cost allocation purposes are referred to the following texts:

- NARUC Electric Utility Cost Allocation Manual (1st Edition, 1973, focuses on embedded CoS studies)
- American Public Power Association, Cost of Service Procedures for Public Power Systems (EES[2]).

Various other specialized cost of service publications and past Ontario reports were located and will be referred to in this group's second Report.

[2] The authors of this publication have advised the former Ontario Hydro, and MEA, on their CoS models (including the 1998 MEA model).

4. Role of Load Data in Cost Allocation Process

Overview of 3 major steps in cost allocation process

Load data is merely one input into a complete cost allocation/cost of service study. The details of an embedded cost allocation study will be reviewed in the Group's second Report. But readers of the present Report may find it informative to know precisely what role load data plays in the cost allocation process.

After any costs, which are directly assignable to a given rate class are handled, the remaining costs are apportioned to the rate classes in three standard steps:[3]

1. "*Functionalization*: The preliminary arrangement of costs according to functions performed by the electric system. Major functions performed by the electric system are production, transmission and distribution and general. Subfunctionalization is the breakdown of major functions into specific cost incurred activities. Functionalization is largely accomplished by the use of a uniform system of accounts. The functionalization process also involves separating various costs between voltage levels or other breakdowns, which assist in the classification of costs.

2. *Classification*. The process of classifying functionalized costs jointly used by classes of service to demand, energy and customer related cost components for allocation to classes of service and so that unit demand, energy and customer costs may be determined for each customer class.

3. *Allocation*. The assignment of classified cost to customer classes of service using prescribed allocation techniques."

Use of Load Data in Third Step

There are a number of ways to allocate distribution demand costs, but all use load data. It has been recognized that load data thus plays an important role in the accuracy of the cost allocation results. The APPA cost allocation manual explains (at page VII-1):

> "The presence (or absence) of data on demand loads is a key concern in a cost of service study. Demand, or capacity, costs are a large portion of total utility costs. Accurate allocation of these costs to customer classes of service depends, in large part, on the accuracy of demand load data available."

The present Working Group understood its mandate was to address the use of load data as an input to the third step of the cost allocation process.

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[3] Taken from page III-5, Cost of Service Procedures for Public Power Systems (APPA).

Use of Historical Ontario Load Data

At the commencement of the consultations, the Group was advised that considerable historical load data, collected by the former Ontario Hydro in the 1980's and early 1990's, was saved and made available on the IMO web site.

The Working Group carefully considered to what extent this load data could be reliably used for setting 2006 rates:

- The Group was advised by two experienced load data researchers that load patterns change over time (air conditioning usage was cited as an important example).Therefore updating of load data was recommended.[4]

- Historical load data can sometimes be used, through sophisticated statistical techniques, to reduce the amount of new sampling required to obtain reliable results. Some LDCs have hired a load data expert knowledgeable in Bayesian statistics to investigate this further.

[4] The same recommendation was expressed in a May 1998 White Paper presented to the MEA's Task Group for Unbundling Cost of Service (see page 8).

5. Use of Coincident Demand ("CP") v. Non-coincident Demand ("NCP") to Allocate Demand-related Costs

Final decision on choice of demand allocator can be deferred if Board wishes

The issues list specifically asked for the Working Group's opinion on the choice of demand allocator, and therefore the Group addressed the issue at length. (Further technical comments are included in Appendix B.)

The Working Group generally agrees non-coincident peak (specifically 1NCP) should be the default method used to allocate demand-related distribution costs.[5] However, given the wide variety of circumstances faced by Ontario's 90plus LDCs, the Group would also urge the Board to allow some flexibility (specific suggestions are made below).

If the Working Group's recommendation to collect 12 months of interval load data is accepted, then the Board will not need to make a final decision on the preferred demand allocator at this time. This is because the load data to be collected will be broad enough to support later adoption of any of the main demand allocation methods considered (CP/1NCP/12NCP, etc.).

Optional Use of CP

The Group believes it is sometimes justifiable to use customer-class coincident demands (i.e., the class demand at the time of the distributor's peak), such as where facilities are designed giving full consideration to the diversity inherent in all of the loads served by the distributor. Specific examples would be facilities that are used to serve the distributor's entire load, for example sub-stations and associated sub-transmission lines for distributors with a single point of supply.

Use of an NCP Allocator Other Than 1NCP

Typically, the non-coincident demand allocator for each customer class is determined by considering all of the customers in the class as one service point and determining the associated maximum annual demand for class. This value is referred to as the Class 1 NCP.

The Group also discussed when an NCP allocator other than 1NCP might best suit a given LDC. The Working Group acknowledges it can be appropriate for a given distributor to allocate demand-related distribution costs using the NCP for each customer class averaged over a number of months where:

[5] A Group member dissented on this point, believing a strong enough case had not been made for the use of 1NCP as a default (for example, for summer peaking distributors, use of 1NCP would relieve the street lighting class of any demand costs; also demand costs would be greatly reduced for seasonal classes that peak in low use months) and instead suggested the choice of demand allocator should await the results of the upcoming load research studies.

- The individual customers in one or more of the customer classes are known to “peak” in different months of the year and these differences are reflected in the design of the facilities used to service different local areas of the distributor.

- The various customer classes served by the distributor “peak” in different months of the year.

- There are a number of months during the year when the distributor’s peak demand is close to its maximum annual peak.

Some distributors may prefer 12NCP when they are particularly concerned about the stability of the results. A load researcher commented to the Group: “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.”

Recommendations - Flexibility combined with Sensitivity Analysis

To combine the advantages of a common default (comparability of results, etc.) with the recognition of LDC diversity, a majority of the Group recommends:

1) The use of the Class 1 NCP is recommended as the common “default” method. Specifically, it is suggested each distributor file a cost allocation study using 1NCP as the demand allocator.

2) To ensure flexibility in completing the studies, both class and customer NCP values should be gathered (recommended on an hourly basis).

3) It is acknowledged it can be appropriate in specific circumstances to allocate demand-related distribution costs using NCP for each customer class averaged over a number of months, or to use Coincident peak (“CP”).

Accordingly, it is recommended a distributor should have the option of rerunning its CoS results with an alternative demand allocation method it believes more appropriate for its specific circumstances (CP, 2NCP, 3NCP, 4NCP, 12NCP). But the distributor must provide a rationale for the alternative allocation method chosen. And the sensitivity analysis will allow the Board, and stakeholders, to clearly see the impact of the alternative demand allocator preferred.

6. Length of time load data should be collected

The consultation issues list asked if Ontario LDCs should collect 12 months worth of load data? The Group notes that the NARUC Electricity Cost Allocation Manual (2nd Edition, at page 178) does recommend doing so: "Data should be collected for at least twelve consecutive months to provide the data required by cost studies in today's ratemaking and costing environment."

Should Ontario LDCs also collect 12 months of load data?

The Group recommends that Ontario LDCs collect 12 months of load data (for use in allocating demand costs in the forthcoming cost allocation studies).

Aside from the value in following generally-accepted North American practices, the Working Group notes several additional reasons:

- 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 months of load data is required for revenue forecasting, which is important in testing whether the derived rates will recover the appropriate revenue requirement.
- Having 12 months of load data allows collection of data for both 1NCP and 12NCP.
- 12 months is the minimum duration required to allow weather normalization of the load shapes (if not done, extreme weather effects may create distortions in the rate design).
- Metering errors can be "bridged" with data from good months.
- Transmission pass-through rates are derived based on coincident peak for the class; therefore, 12 months of data is needed to capture coincident peak.

The Working Group understands it would be preferable if the newly installed load data meters were "test run" for a month. Thus, when establishing project time lines, a 13-month data collection period is ideal. There are other advantages to a longer sample period: "Recording of any particular customer should extend over a twelve-month period; recording over thirteen or fourteen months would even be better in that secular growth could be detected." (Page 31, Ontario Hydro Report R & U 79-5, Load Research for Cost Of Service Studies.)

7. Use of interval load data for cost allocation purposes

Installing interval meters for load data sampling

> In response to the question in the original issues list as to "what type of load data should be collected", the Working Group recommends that interval load data be collected, in order that both the class and customer NCP can be calculated.

The present Working Group did not consider it to be part of its mandate to consider the general merits of increasing the use of interval metering in Ontario (for example, as a means of improving demand responsiveness).

From the point of view of the need to collect updated load data for use in the upcoming cost allocation studies, the Group's reasoning in favour of installing interval sample meters was as follows:

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 used.

Advantages for cost allocation purposes from collection of interval load data

The Group understands that if 12 months of interval data is collected, the LDCs will have the flexibility to later determine which of the various potential demand allocators[6] best suits their specific circumstances. Under the recommended approach, the Board will not have to make a decision as to which specific demand allocator is to be preferred in its upcoming load data collection directions.

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[6] Even LDCs wishing to use the CP option will need to collect time-related interval consumption data to compute the contribution of each customer class to the system peak.

8. Interval Meters[7]

The issues list asked the Working Group's advice on whether there were any practical constraints if additional metering is required. The Group identified the following implementation issues regarding the interval sample meters needed.

Acquisition and Installation Costs

a) *Acquisition* - The type, and hence cost, of an interval meter depends upon how the data will be retrieved. Two options discussed were retrieving data through a telecommunications line or reading data through optical ports. If the meter has mass memory, it can be read through optical ports using MVLT and therefore does not require a modem.

- Residential – single phase, acquisition cost can be as low as $250-350
- General Service – polyphase, cost significantly more (e.g. $750-1000).

Also, there are companies that "lease" AMR devices with an average monthly charge of $4-5 per month; however, these arrangements are usually based on 2-10 year leasing arrangements.

The sample size design should take into consideration the possibility of some data being disqualified due to problems such as excessive power outages on sample, meter malfunctions, etc. Therefore extra meters may have to be purchased (and installed) to account for this.

b) *Installation* - Meter installation costs must also be considered. These will vary depending upon whether an LDC has to hire an outside contractor. The estimated cost is between $50-100 for a residential meter installation, and up to $2000 for a transformer-type interval meter installation.

Some randomly selected customers may present meter installation difficulties such as remote locations, non-availability of communication lines, and access problems such as inside meters. It may be beneficial, given the tight time lines, to suggest selection of sample alternates.

Data Reading Costs

Unique LDC circumstances will determine whether it is more cost effective to read data (through optical port, monthly) using MLVT or using telecommunication. Distributor-owned telephone line installation costs can be up to $150, with monthly charges at $50/month.

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[7] For those readers interested in more details about interval metering, see the further information set out in Appendix C.

If using units that do not interfere directly with data collection and analysis software (e.g. MV 90), additional costs may be incurred for data collection services and translation (estimated at $4 per month for Residential/small General Service to $7 per month for large General Service).

Additional costs for the increased number of interval meters may be negligible or significant dependent upon the excess capacity in the distributor's system. For LDCs that do not have their own systems, but pay monthly or annual fees for data collection and settlement services, they may find that their service provider is unable to accommodate this increase in volume or total fees may be higher.

There may be small distributors with no interval customers, which rely solely on IMO data for their wholesale metering. These distributors would have the added effort of locating and contracting services they previously did not require, and that may prove administratively and financially challenging.

Time Lines for Installing Sample Meters

Aside from costs, the other major practical constraint is project time lines.[8]

a) *Sourcing Meters* - The Group understands that in the past, delivery time can be up to 10 weeks (and more if there should be a supplier capacity problem). There may be potential for shorter delivery time if LDCs tender as a group.

b) *Installation* - A period for meter installation time must be allowed. Time will also be necessary to coordinate installation with telephone companies.

c) *Customer Consent* - Sufficient time should be allowed for customer solicitation. Based on past experience, some Group members were concerned about potential difficulties in getting customer consent. It was asked that the OEB somehow inform customers that they may be asked to participate in a load research program, to promote better customer co-operation. It could be in the form of literature (must be from a source independent of the individual LDC) for distribution and a resource to refer customers to for confirmation/information.

d) Board Approval and Directions – Some LDCs are ready to order interval meters. Early Board approval of Province-wide data collection is requested.

e) Testing of New Meters - Ideally, the meters installed should be tested for a month to ensure stability of new equipment.

[8] The Ontario Load Data Research Group has obtained professional advice that other information should be collected, such as appliance saturation information, to allow the Provincial data to be used to generate LDC-specific load profiles. Thus additional steps (and expense) will be incurred to bring the project to completion.

Conclusions re time lines:

In response to the question posed of what practical constraints may exist if additional metering is required, the Working Group estimates it will generally take at least 5 months to commence load data research once the Board issues directions on acceptable sampling methodologies.

The exact start-up date will likely vary from LDC to LDC. Larger distributors, with more resources, as well as those distributors that have been actively following the technical debates in this Working Group, may be able to commence their load data research program somewhat earlier than the rest of the industry. It may also be possible for those LDCs working together to speed things up by sharing experiences, etc.[9]

The Working Group believes January 1, 2004 is not a technically feasible target starting date. If the Board were to approve the recommendations of this Report by the end of September, around March 1, 2004 would be the earliest realistic starting date for load data collection by the entire Ontario industry.

The Working Group would cautions that if the common start of load data collection is delayed into the second quarter of 2004 for any reason(s), then filing the cost allocation studies in 2005 on a timely basis could be affected (given the long lead times).

The Working Group urges the Board to carefully assess how early in 2004 it is possible to commence load data collection. The Working Group looks forward to the opportunity to work with Board staff to ensure a smooth as possible commencement of load data research.

If the Board declines to accept joint collection of load data and each of the 90plus LDCs is required to collect its own load data, then it is believed the technical and financial constraints to be faced by the smaller LDCs will further delay overall time lines. The Working Group has not confirmed any other jurisdiction has mandated numerous small utilities to collect load data to PURPA standards (although the group understands large utilities in other Canadian provinces have done so, such as Manitoba). The Working Group is aware of successful cooperative load data programs elsewhere, but is not aware of any jurisdiction where numerous small utilities each successfully undertook a statistically- rigorous load data research. Such a goal may be very ambitious.

[9] A range of optimistic to pessimistic load data collection start dates for the Province-wide cooperative initiative are set out in Appendix D.

9. Accuracy of Meters for Load Data Collection

Standard meter accuracy

All meters used to bill customers are required to be Measurement Canada ("MC") approved.[10] The current Measurement Canada approved single-phase meters available, that can collect interval meter data on a residential or small commercial/industrial customers (generally less than 50 kW), have an accuracy typically +- 1% (2% total).

Polyphase demand meters used to bill larger commercial/industrial customers are required to be MC approved and typically have an accuracy of +- 0.2% (0.4% total). Transformer-rated meters use Instrument Transformers supplying voltage and current to these meters and have an accuracy of 0.3 to 0.6%.

Supplemental Metering

If another meter (i.e. additional meter in series) is to be used to collect interval data for the purpose of load profiling, while leaving the original billing meter in place, then it should be of the same accuracy as the meter currently being used to measure and bill the class. Accuracy requirements should meet, but need not exceed, the MC tolerances for revenue billing meters. Consistency of collected data across the class/LDC/Province is important.

Conclusions

The Working Group recommends that the additional metering to be purchased by distributors for purposes of load data research be accurate to within a plus or minus 1% tolerance.

Further questions re appropriate use of substation/transformer metering

There are instances where meters and instrument transformers ("IT") of lower accuracy (less than metering class standards) have been installed to obtain data on a substation feeder. These meters are typically used to provide LDCs with information for distribution planning purposes. The ITs both current and potential are usually in the 2.5% relaying accuracy class. The error associated with the ITs is therefore 2.5 squared, or 6.25%. The error in the ITs is greater than the error on the meter recording the data. Worse case combinations of low IT error, and high meter error, could result in data error of significant values.

[10] Some Group members understood the approval status of certain meters was the subject of ongoing discussions.

The accuracy of data from these types of schemes across the Province will probably vary considerably and the error could be as high as 10%. If the data collected is used to support other individual customer load data collected with meters of within plus/minus1% accuracy then it could be of value, but not on its own.

Note even if the meters to be used at a transformer were of high accuracy, the majority of the Working Group recommends load at a transformer station should only be used as a check on the reasonableness of load data collected under the standard industry practice (metering of individual randomly selected customers[11]).

Dissent

Several Group members acknowledge that transformer station metering may or may not be of revenue accuracy, but nevertheless believe its use would be acceptable for allocating the costs of a specific facility between the different classes using that facility, since the accuracy of the transformer meter would still be greater than the plus/minus 10% overall load estimate target accuracy.

- Ontario readers may be interested in knowing that a presentation made to the Virginia state cooperative load research group indicated that in the past, there were a number of other methods used to collect load data for CoS studies (such as "RUS Demand Tables, Bary Curve, Substation Hourly Data, Borrowed load research, Other surrogates"), but all these were viewed as less accurate and precise. In effect, the statistically-rigorous joint data collection option favoured for use in Ontario (and implemented elsewhere) will lead participating local distributors towards North American best practices in this area, and the Working Group believes this represents a major achievement.

[11] Readers interested in a theoretical justification of the approach favoured by the majority may wish to review the detailed Ontario Hydro study Load Analysis for Cost of Service Studies, Report R & U 79-5.

10. Meter Data Management

After the sample meters are installed and they start reading “raw” load data, proper steps must be taken to manage the data gathered:

- *Data-validation* - This checks “errors in the metering and retrieval process that cause the data collected not to reflect actual usage”. (For details, see pages 6-4 to 6-6, AEIC Load Research Manual.)

- *Data Editing* - “Editing can sometimes salvage data from incomplete records or correct obvious data errors. There are many sources of load profile data errors in the recording and subsequent data-gathering operation – some human, some electrical.” (See pages 6-6 to 6-10, AEIC Load Research Manual.)

Conclusions regarding data validation and editing

The Working Group recommends any distributor, or group of distributors, follow an industry generally-accepted procedure for data validation and editing.

- The Group suggests an acceptable guide to data validation, estimation and editing is the IMO publication “Market Manual 5: Settlements – 5.2: Meter Data Processing”.

Software for data management

In practice, some type of software will be necessary to manage the load data to be read. Each distributor participating in load data research will need to make its own decision as to which software to use, and how to acquire the expertise.

The Group benefited from a presentation on the MV-90 software package, which the IMO has recognized for use in Ontario. See Appendix E for further details.

11. Load Data Sampling Methodologies

Multiple statistically-reliable methods available

The Working Group understands that there are a variety of recognized statistical methods for designing a load data sampling program.

- Appendix F outlines some of the major sampling techniques, such as simple random, systematic, and stratified sampling.

The Group believes an individual LDC should be allowed the flexibility of using any generally-accepted sampling method that produces statistically-verifiable results. It is therefore recommended the OEB accept use of any of the statistical sampling methods discussed in the AEIC Load Research Manual (2nd Ed.).

Merits of stratified sampling

The Group wishes to draw attention to the merits of stratified sampling, which provides statistically-accurate results while requiring fewer sample meters.
The AEIC Load Research Manual describes several potential stratification methods (see page 4-11), and the Group suggests Ontario distributors be given the flexibility to decide which one best suits their circumstances:

- "Categorical variable, such as demographic data from customer billing files, may also be used to stratify the population. For example, residential customers may be grouped by type of electric appliance (electric heat and water heating or electric heating only) or type of residence (single family or mobile home), as long as the information can be identified for each unit in the population."

- "When billing energy or demand data for a prior month are used to stratify the population, that month is usually a peak month. Using the sum or average of billing data from more than one prior month as the auxiliary variable is also common."

Consistent sampling method desirable for cooperative load data research

It is further suggested that any group of Ontario distributors conducting load research on a cooperative basis should use the same sampling method. For instance, after careful consideration, the 40plus members of the Ontario Load Data Research Group reached a consensus on stratification by end use. (Stratification by average consumption was raised by some members of that Group, but ultimately dropped. While no additional appliance saturation information is required, as many as four times more meters could be needed.)

12. Statistically-Reliable Options for Collection of Load Data

The issues list for the cost allocation consultations included the following: "The Distribution Rate Handbook presently recommends 'achieving economies were possible through joint development of load data' (para. 1.4). *How can joint collection of load data be best implemented?"* (italics added)

North American Precedents for Joint Collection of Load Data

Ontario stakeholders may be interested in knowing that the merits of joint collection of load data have been previously documented. The U.S. Electric Utility Rate Design Study (sponsored by NARUC, APPA, EEI, and EPRI) listed numerous advantages of a coordinated load research effort:[12]

- "The total number of customers to be sampled under a pooled approach would be less than that of individual testing programs.
- The investment and operating costs of conducting load research would be spread over several utilities.
- Only one set of computer programs would need to be developed for extracting, editing, storage, and reporting the test data.
- Other items with high fixed costs … might be shared with an improved utilization rate.
- The timetable to acquire the operational knowledge and skills associated with a load test program would be reduced since all participants would learn simultaneously."

The Working Group believes these advantages would apply to Ontario as well, and thus give effect to the Board's admonition to consider "what cost allocation methodologies are appropriate and practical". It is interesting to note that a prior Ontario Hydro Report[13] load data collection study commented: "It is clear that here would be considerable redundancy if every municipal distributor carried out its own load analysis". The present Group agrees.

The Working Group has also ascertained that there are several ongoing cooperative utility load research programs in various U.S. states (and therefore there is ample precedent for joint data collection, such as proposed by the Ontario Load Data Research Group). The Working Group is aware of industry-organized load research groups in the states of Virginia and Alabama (there may be more).

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[12] See Volume No. 74A, "The Rate Design Study: Load Research", Volume 1 (Nov. 1979) at page 4-6. It also reported "several private utility groups have been coordinating load research testing for several years".

[13] See page 7, Load Research for Cost of Service Studies, R & U 79-5 (June, 1979).

<u>Option #1) Collection of Complete Load Data by Individual LDC</u>

The Group felt it was important, as a matter of principle, that each LDC in the Province retain the option of conducting its own load data research (using statistically-verifiable sampling techniques). Given the tight time lines, preparations would have to start immediately.

But the Working Group cannot recommend this approach for practical adoption, since it is by far the highest cost way to collect accurate load data. The Group is unaware of any Ontario LDCs planning to collect load data on its own, and this option may well prove to be of theoretical interest rather than practical importance.

<u>Poor cost-to-benefit ratio of individual LDC load data research</u>

Individual and joint collection of load data can produce the same high quality results, if designed in a statistically-sound manner and properly implemented. However, the costs of each option differ dramatically.

Ontario currently has around 90-95 LDCs. If each electricity distributor were to conduct its own load research, and assuming a minimum of 40 meters a class (to protect against data loss), the total sample size required to sample the residential class across each LDC in the Province would be around 3700 interval meters at a minimum. The actual number of meters required under this option would be higher because those distributors with more heterogeneous populations will require greater number of meters to obtain statistically-reliable results.

- In contrast, the Ontario Load Data Research Group, for example, would plan to use around 700 meters to sample the residential class for the entire Province, with statistically-reliable results still expected. <u>Thus option 2) represents a savings of at least 3,000 sample meters compared to option 1)</u>.

- The Working Group wishes to stress that the cost of updated load data would be prohibitive for many LDCs if option 1) were mandated. It is thus very important to give effect to the comments encouraging “joint development of load data “ in paragraph 1.4 of the DRH.

- The Working Group notes the AEIC <u>Load Research Manual</u> confirms the concerns expressed above: “For some small utilities (i.e., smaller utilities not originally subject to PURPA), the cost of designing and implementing a load research program is prohibitive” (see page 2-12, 2nd Ed.).

<u>Option #2) Joint Collection of Load Data via Province-wide Sampling</u>

The Working Group had the benefit of reviewing older reports explaining how Province-wide sampling had been organized when Ontario Hydro operated an active load research programme.

- A summary of the load data sample design from the 1980's residential TOU experiment was found (see discussion in "Sample Design Methodology, The Energy Efficiency Potential Of the Existing Electrically-Heated Housing Stock in Ontario" (December, 1987)).

The material reviewed explained that Province–wide load data collection was organized as follows:

- The Province was divided into major regions, and load data sampling meters were installed in each region.

- Meters were installed in the rural system, and in a group of participating urban utilities.

The Group also benefited from a guest appearance by the former head of Ontario Hydro's load research programme, who reviewed the design of the TOU Province-wide load data sampling program and made the following comments about use of that model as a template for current plans:

- The data collected for regulatory purposes should be of high quality, and therefore up to 700 residential meters could be needed Province-wide for the present project (fewer meters were used in the TOU project).
- The LDCs to be included in any new Province–wide load sampling program should represent residential customers with a variety of lifestyles.
- The total number of new meters required would be reduced by the number of suitably located meters already installed in LDCs joining the initiative.
- A Bayesian approach may allow use of the past Ontario load data to assist in current statistical analyses (further study required).
- Ontario load data from the 1980's and early 1990's (now posted on the IMO web site) could not be used to eliminate the need to gather new load data, as load profiles change over time (both guest experts gave the example of increased air conditioning usage).

At the moment, over 40 LDCs, serving the bulk of the customers in the Province, have indicated a desire to form a single, Ontario-wide load data research program. In effect, most of the distributors with the resources to fund the installation of the hundreds of additional interval sample meters needed have elected to support option 2).

Option # 3) Joint Collection of Load Data by Group of LDCs

A group of adjacent GTA-area LDCs had seriously considered this approach, but the cost of undertaking the additional analysis to statistically control for major variables (such as customer mix and appliance saturation) was such that a single Province-wide approach was just as cost-effective and easy to join.

To allow distributors across the Province maximum flexibility, the Working Group recommends any group of distributors be allowed to jointly collect load data, provided they do so in a statistically-rigorous manner that will lead to the creation of LDC-specific, weather-adjusted profiles meeting the PURPA accuracy targets.

As a practical matter, given the economies of scale of a Province-wide approach, the Group recommends option 2) as the lowest cost of the three high quality load data collection options advanced. The Working Group is not aware of any Ontario distributors spending funds to prepare a proposal under option 3).

Conclusions

The Working Group recommends that the Board allow any group of distributors to join together and form a Province-wide load research initiative, provided the participating members include a geographically-varied sample of urban LDCs, along with some rural system participation, and the LDCs sampled include residential customers with varying lifestyles.

During the course of the consultations, the distributors agreeing to voluntarily participate in the Ontario Load Data Research Group grew significantly. The resulting synergies benefit all. For instance, the number of interval meters already installed in the GS>50 kW class was found to be in thousands.

To ensure reliable results, the working group recommends that any joint load data collection initiative be organized in a statistically-rigorous manner.

For example, the data to be collected on a Province-wide basis by the Ontario Load Data Research Group is intended to be used to generate LDC-specific load profiles that meet the PURPA accuracy targets.

Overall, the Working Group asks the Board to allow implementation of the least costly of the three equally statistically-rigorous options identified, namely Province-wide joint data collection. It is important Ontario stakeholders understand that option 2) is not of lower quality than the others, just of lower cost.

13. Use of Jointly-Collected Data to Produce LDC-specific Load Profiles

The immediate goal of the Ontario Load Data Research Group is limited to the cost-effective collection, on a statistically-sound basis, of load data from a geographically diverse sample of distributors that serve customers of varying lifestyles.

Further technical steps are necessary to make use of the data collected to generate actual load profiles for participating LDCs.

For example, one of the larger members of the Ontario Load Data Research Group has technical staff with the experience and the sophisticated software to use the Provincial data, along with further information to be supplied by a distributor, to produce on a cost-effective basis LDC-specific load profiles that meet North American accuracy guidelines.[14]

But to give distributors maximum flexibility, the members of the Ontario Load Data Research Group will remain free to go to any party to process the Province-wide data into LDC-specific load profiles.

Staggering of filings

The Working Group advises that if the Board wishes to follow the common practice of having the load profiles weather adjusted, then many LDCs may decide to have the distributor with the most expertise in the area do that as well.

To avoid a “bottleneck” that may occur if the same party prepare the load profiles for the bulk of the Ontario LDCs in 2005, the Working Group recommends that the Board adopt a staggered filing system for the cost allocation filings.

For instance, 20-25 LDCs could be asked to file sometime in July of 2005 (assuming load data collection commences smoothly in the first quarter of 2004), and the rest in stages during the reminder of 2005 and early 2006.

The goal would be to have new rates for all distributors come into effect on the same date (e.g. May 1, 2006).

[14] If the Board is willing to allow case studies to be undertaken as part of the future cost allocation consultations, Hydro One Brampton has volunteered to illustrate and confirm the methodology proposed by the Ontario Load Data Research Group to generate a LDC-specific load profile.

14. Accuracy of Load Data collected for Cost Allocation Filings

Statistically-sound results recommended for Ontario regulatory purposes

The Working Group's understanding of Canadian, and North American, "best practice" is that load data to be used for rate setting purposes, such as cost allocation studies to be filed in Ontario, should be collected and analyzed using demonstrably-accurate methods.

The Working Group carefully considered the following important observation from the AEIC Load Research Manual (2nd Edition, page 4-4) on this topic

> "A design accuracy of +/- 10% at the 90% confidence level at the system and class peak time was specified in 1978 by PURPA for all major rate classes. Although these federal standards were lifted in 1992, the PURPA specification remains somewhat of a load research standard, *particularly for samples that will be used to support rate cases or other regulatory requirements."* (italics added)

The Working Group would also recommend that all Ontario distributors use LDC-specific load profiles developed through statistically-sound methodologies, so that the Board and other stakeholders can be confident that if rates are to be adjusted following the cost allocation studies, it will be done so on the basis of reliable data.

- The Working Group's second Report will include elaboration from a user's point of view on the importance to Ontario electricity consumers of high quality cost allocation studies.

Because the Group decided to advance three load data collection options that each could meet the PURPA guidelines, this Report could focus on discussing which of these high-quality options was the most cost effective.

Use of PURPA "target" in Ontario

For purposes of designing the upcoming load sampling program, the Working Group recommends Ontario also follow the PURPA[15] target accuracy of plus or minus 10% at 90% confidence.

To fully understand the policy implications of this, it is helpful to consider the following comments on the history of the PURPA rules found in the APPA publication Cost of Service Procedures for Public Power Systems.[16]

[15] See former *Public Utilities Regulatory Policies Act*, 1978 (U.S.).
[16] See page A-6, in an Appendix entitled "Overview of the Public Utility Regulatory Policies Act of 1978".

(1) *“[T]he accuracy level is now only a target to be achieved in determining sample size rather than a standard that should be used for projection of load data*
(2) the target applies only to measurement of loads at time of system and group peaks rather than for each hour and
(3) the accuracy level has been lowered to plus or minus 10 percent at a 90 percent confidence level.” (italics added)

The Working Group recommends that for the upcoming Ontario cost allocation studies, the Board also apply the final PURPA rules (target accuracy plus/minus 10% at 90% confidence).

- The Ontario Load Data Research Group has retained independent expert advice to prepare a cost-effective cooperative load data research program designed to meet the PURPA accuracy target.

If the Board were to mandate the PURPA figures as a standard rather than target, Ontario distributors would have to “over sample” to be assured of reaching the mandated accuracy. There was vigorous discussion within the Working Group over the cost versus benefits trade-off regarding load research for cost allocation purposes (see Appendix G), and there is no consensus among Group members on the need or benefit of a more onerous sample accuracy requirement.

15. Should smaller LDCs follow the same load data rules?

The Working Group generally focused on principles of general application to the industry. However, LDCs in this Province range in size from those serving fewer than 1,000 customers to those serving over 1,000,000 customers. This raises the question of whether it would be desirable to subject all of the electricity distributors in the Province to the same set of load data rules.

Variation in per customer cost of accurate updated load data

While the Working Group has concentrated on giving technical advice on load data to the Board, the members also wish to draw attention to the following:

1) LDCs understand the importance of ensuring rates reflect cost causality. However, it should be acknowledged they would be commencing the cost allocation studies in a period of regulatory change.

2) Some LDCs - potentially of any size - may find themselves experiencing financial pressures. The immediate expense of a cost allocation study represents an additional cash flow burden.

3) The cost for an individual distributor to collect its own load data will exceed, by many thousands of dollars, the cost of participating or acquiring load data from the planned Provincial sampling program.

4) While all distributors will avoid significant expenses under any successful cooperative initiative, the per customer cost of collecting and processing load data will be the highest for the smallest LDCs.

Group members would further comment:

- It is technically feasible to generate statistically-sound load profiles for each LDC in the Province. But to allow LDCs to better manage the expense of gathering such high-quality load data, the Working Group asks the Board to follow the common North American practice of permitting use of the same load data results for a period of time (such as 5 plus years).

- Even if a joint load data collection option is approved, the smallest distributors in the Province (several have under 1,000 customers) will likely have higher per customer costs for completing the cost allocation studies.

Should the same load data accuracy guidelines apply to all LDCs?

The Working Group has focused on data collection methods which are planned to generate load data results targeted at plus or minus 10% accuracy (with 90% confidence), which is understood to be the North American industry norm for load research. The Group has also learned how load data could be weather normalized for each LDC, using proven Ontario expertise.

The Working Group understands there are other potential means to generate load curves (as mentioned in dissent above), but these were all of lower, and often unverifiable, quality. The Group heard from the management of a smaller distributor that it was important to avoid the impression that customers of some LDCs will be treated differently.

The Working Group therefore recommends that the same PURPA load data accuracy target apply to all Ontario electricity distributors.

The Working Group would urge caution if the Board considers allowing a two-tiered standard of quality for load data amongst the various Ontario LDCs:

- It may cause future difficulties if a precedent were established of treating the regulatory obligations of some LDCs differently.
- The customers of the LDCs using the poorer quality load data may not have the benefit of reliable cost allocation results.
- If differing quality input data is used in setting 2006 rates, it will be difficult for stakeholders, the OEB and Province to have confidence in any future comparison of rates amongst LDCs.
- If LDCs are competing for business or growth with adjacent LDCs, then fair competition should require everyone follow the same rules.
- If all LDCs are to be subject to yardsticking as part of PBR II, it is important that the same regulatory burden be placed on all.

Addressing concerns of smaller distributors

While the management of a smaller LDC was supportive of following the same rules as the rest of the industry, concern was expressed about their total regulatory burden. In this regard, the Working Group wishes to stress that a practical approach to completing the cost allocation project is important (as acknowledged by the Board in its October 28, 2002 letter).

The present Working Group understands that the 1998-2000 MEA Task Force (which included participation of two sets of experts) recommended the results of the MEA's modified minimum system analysis still be acceptable.

If the Board chooses to require that even the smallest LDCs use high-quality load data (note the group did not confirm this is common elsewhere), the Working Group recommends it will become important to later approve a common default categorization option, so that the total cost of completing the cost allocation studies for the bottom third of the industry does not become seriously out of line with the conceivable benefits to their customers from updated cost allocation studies.

The present Working Group would also like to stress the benefits of a cost allocation case study involving a distributor with under 10,000 customers, to confirm the cost allocation principles being considered by the Working Group apply equally as well to the special circumstances of small Ontario LDCs.

Importance of a joint data collection option to smaller LDCs

If the Board agrees with the recommendation that all Ontario LDCs will be required to obtain load profiles that meet the PURPA target accuracy, then the Working Group believes it will become crucial to also approve some form of joint data collection that will allow small LDCs to meet the PURPA standards in a cost-effective manner.

If small LDCs were each forced to undertake their own independent load research program, it is believed the cost will be proportionally higher for these LDCs since the sample design literature reviewed indicated that if the population is small, then the sample size is larger as a percentage of the total population.

16. Introduction to weather adjustment of load data

After the Working Group met, they decided to examine the issue of weather - normalizing the load data to be used in the demand allocators.[17]

The Group looked at this issue in considerable detail, and its final views will be set out in a future Report. (From a technical point of view, early resolution is not required; but distributors on the working group wanted to know the full amount of the likely expense for accurate load data.)

The following (taken from *Weather Normalization of System Peak Demands*, Arkansas Power and Light Company, October 1988) summarizes why the issue of weather normalizing load data is important:

> "Weather normalization of peak demands results in a more stable allocation of demand-related costs to weather sensitive classes from year to year by adjusting the classes' actual peak demands to a peak demand reflective of normal or typical weather conditions."

Size of weather effect in Ontario

The Group benefited from a presentation by a load forecaster with a major Ontario electricity distributor, who explained the size of weather effects in Ontario:

- Energy: 1-2% weather correction
    - equal to 1 or 2 years growth for some LDCs.

  Peak: as high as 10% for some months
    - equal to 5-10 years of growth for some LDCs.

[17] Please note the Group did not discuss the weather normalization that might be required for forecasting revenues (this should be discussed when establishing the 2006 revenue requirement is examined). The U.S. cases indicate several major issues arise in that context: should there be weather normalization of the revenue forecast (some regulators require it for natural gas utilities but not for electricity utilities); and what length of time should be used when weather normalizing (some jurisdictions use a shorter period, such as 10 years, on the grounds weather has been warmer in recent years and use of a 30 year average would be unfair to customers).

Load data weather adjustment options

The Working Group identified three possible options to weather normalize the load data to be used in the demand allocation method adopted for the upcoming cost allocation filings:

- average extreme values (i.e., average of 30 years of yearly extreme values);

- the maximum extreme values (i.e., one year of extreme value which is the highest of 30 years); or

- at a late date, the group came upon a report of a utility using simple average weather (there was no time to explore this further[18]).

Introduction to substantive issues

The current view of the Group is to recommend weather adjusting load data to the average extreme values, that is, the first of the three options listed above.

- As will be explained in a future Report, the first option is the same one currently employed by the IMO, and others, in Ontario.
- Note the Group could locate no reference materials that addressed whether weather normalization for system capacity planning should differ or be the same as weather normalization for cost allocation purposes.

When exploring the issue of how best to weather-normalize load data, the Working Group started to become involved in important theoretical questions that warrant further attention.

- The initial view of most Group members was that peak design capacity was the leading determinant of cost causality; but a guest load data specialist suggested, to the contrary, “besides meeting the peak demand, the distribution system is also designed to deliver energy and to have a certain reliability throughout the year”.

The Working Group understands there will be major financial implications if one weather adjustment option is preferred over another, therefore informed stakeholder participation in the final decision is important.

[18] It appears from reported decisions that this method is the predominant one used when weather normalizing the revenue requirement. But the present Group is inclined to recommend a different method for weather normalizing load data.

Costs v. benefits of weather adjusting load data

Some Working Group members expressed concern over the additional expense represented by weather normalization. This was part of an ongoing debate about the costs versus benefits of more precise data for the cost allocation studies.

The following observations from a load researcher who appeared as a guest are repeated for background:

Should loads be adjusted if the weather looks normal in the test year?

"Some were recommending that if after the test year, the weather looks normal, then a utility should not have to adjust the load. What looks normal from one utility's perspective may not be normal from another utility's perspective. It's not whether the weather is normal, but whether the load profiles after adjusting for the sensitivity of the customer load profiles to weather is normal. Because of the different saturation rates of equipment (e.g., central air conditioning) one utility may not be very sensitive to weather relative to others."

Should large LDCs weather-normalize and small LDCs 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."

It should be noted expertise currently exists in the Province to weather adjust each LDC's load profile for a one-time cost of less than 50 cents per customer for a distributor of 5,000 customers. The economic pros and cons of weather adjustment will be discussed in full in a future Report.

- Note this Working Group has recommended that the same load data rules apply to all LDCs. Allowing some distributors to not weather- normalize their load data would be inconsistent with this goal.

Need to Normalize Load Data for Unusual Circumstances

It was also mentioned that load data might need to be adjusted for known special events, such as an ice storm, which reduces load for a period. Note the reference material on load data research indicates professional judgment and experience is required to best interpret the raw data obtained.

17. Relationship between Load Data Collection and Rate Classes

Theory

As the AEIC Load Research Manual notes (at page 1-5): "Load research data determines the contribution of each class to demand-related costs, an important factor in cost allocation". Thus load data should generally be collected for each of the major current rate classes. In addition, sound rate making principles require that rate classes reflect cost causality. This means there generally needs to be load data research for any planned new rate classes. (Exceptions noted below.)

As a result, there is a close and iterative relationship between current rate classes, future rate classes, and load data collection. The APPA cost allocation manual (page V-1) explains:

> "An objective of cost of service is to provide costing information which can be used in the design of rates. This requires that definitions of customer classes of service be specified prior to conducting a cost of service study so that cost can be allocated to newly defined classes. …
>
> A review of present rate schedules and customer class definitions should precede the performance of a cost of service study to plan for the necessary accumulation of costing information for which rates can be designed based on costs derived."

To conclude, while the "going-in rates" consultations have addressed load data collection before rate design, the practical question of which classes to collect load data for commencing 2004 links the two set of issues. The Board, and other stakeholders, should be fully cognizant of this important area of overlap.

- There may be various other subtle overlaps between cost allocation and rate design. For instance, the Group's goal of producing accurate LDC-specific data for the forthcoming cost allocation studies may have the effect of encouraging some rates in the Province to be driven apart further (to the extent differences in rates reflect differences in underlying costs), unless special measures are taken at the rate design stage. It was explained that under the pre-unbundled guidelines, specific steps were taken to hold rates together across the Province.

Over the long run, rate design and cost allocation could evolve together. For instance, after reviewing the results of the 90plus upcoming cost allocation studies, a determination could be made if a more fundamental review of rate classifications is warranted in Ontario sometime in the future.

Practical Recommendations

The Working Group understands there are a variety of theoretical options for rate classifications. However, as a practical matter, sampling meters have to be installed in the next few months to meet the Board's time lines. The Group concurs with the practical approach suggested in the Board's letter of October 28, 2002.

In this regard, this Working Group understands that the Municipal Electric Association's Task Group for Unbundling Cost of Service (which included participation by two cost allocation experts) agreed the current number of rate groupings was an acceptable starting point.

The present Working Group believes that the current number of rate classes is sound and recommends it be the basis of starting load data research.

For example, the Ontario Load Data Research Group has decided that four major rate groupings (residential, General Service<50 kW, General Service>50 kW, Large User) should be the focus of their Province-wide load research program. Any LDC having, or wishing to introduce, further rate groupings may likely need to undertake additional LDC-specific load data collection.

- Some specialized rate classifications employed are discussed in Appendix H. Deemed load profiles are discussed later as well.

Every distributor should consider the potential load data needs for <u>each</u> of its current (and planned) rate classifications (as noted below, the Working Group believes a few rate classes may not require separate load data).

<u>Major Groupings in Province-wide Load Sampling Proposal</u>

The Ontario Load Data Research Group, for example, will focus on the following major rate groupings:

1)Residential

The Ontario Load Data Research Group plans to place around 600 new interval meters amongst residential customers around the Province, as well as make use of around 100 currently installed residential interval meters. At the Province-wide level, both regular and seasonal residential users will be sampled (any other desired residential subclasses will be left to individual distributors to sample, if needed).

2)General Service<50 kW

The Ontario Load Data Research Group will treat this as a separate grouping for load data purposes. The Research Group has access to a few hundred installed interval meters in this rate grouping. At present, there are no plans to install additional sample meters (some use will be made of a residual estimation, as used, for example, in prior Ontario Hydro load research studies).

3)General Service> 50 kW

The Ontario Load Data Research Group is proposing to treat this as a separate rates grouping for load data research purposes. The Research Group has access to thousands of installed meters in this grouping, and it is expected such a large number will mean no additional metering will be necessary to obtain a reliable sample. The Research Group's expert will be consulted on how to most efficiently make use of the available meters in a defensible manner.

4)Large Users (5000 kW)

Since these are already interval metered, the Ontario Load Data Research Group will be leaving the collection of load data for this class to individual distributors.

5)Intermediate Users

Several distributors across the Province currently have an "intermediate" use subclass. Such a grouping may be used by distributors that have individual customers with loads less than 5,000 kW, which nonetheless comprise a significant portion of net system load.

The Ontario Load Data Research Group proposes to treat intermediate class customers the same as Large Users. It will be assumed all intermediate class customers are already interval metered; if not, some installation of additional metering would be required. The affected LDCs should examine this carefully.

The Working Group noted the comments regarding intermediate use in paragraph 1.4 of the Distribution Rates Handbook, which appear to suggest cost allocation support is not required for such a grouping. The Working Group, however, doubts the technical soundness of this position. The Working Group therefore recommends full cost justification for any intermediate use rate grouping in the upcoming cost allocation filings, and it is requested the Board's upcoming directions address the matter.

18. Building flexibility into load data sampling to accommodate future rate classification options

Because the present decisions made regarding load sample design may impact the range of options available when rate design issues are subsequently examined, this Working Group developed specific suggestions to ensure a reasonable amount of future flexibility.

1) Flexibility to Change the General Service 50 kW Boundary

Special attention was given to this topic in light of the comments in RP-2000-0069 stating the “Board will initiate a review of the rate design for the general service class” (paragraph 3.5.7).

The current rate classes are generally a continuation of historical rate classes that were in place prior to industry restructuring. They were created to group customers with similar cost profiles. The most significant change made at the time of the rate unbundling was the segmentation of the General Service class at the 50 kW level, which had not existed in the past rate classification.

The previous rate classification recognized that a 50 kW demand and 250 hours use was an appropriate point at which demand-related costs should be explicitly identified. As a result, a specific demand charge was implemented for loads greater than 50 kW. Loads less than 50 kW had no explicit demand charge and the demand-related costs were rolled into the 12,250 kWh energy block. Therefore all customers, regardless of demand level, paid towards the demand-related costs. A major savings to the utility in this rate design was in not having to install demand meters for all general service customers.

In a past Manitoba Hydro cost of service decision, that utility was asked to look at the merits of subdividing the general service class at a different boundary (see page 39, Manitoba Board Order 7/03). This Working Group believes it is useful to allow future Ontario rate design consultations the flexibility to examine the pros and cons of moving the current General Service boundary to say 100 kW.

The Ontario Load Data Research Group expects there will be sufficient General Service interval meters under their control to provide, if requested, load data results to support the possible change of the General Service load boundary to 100 kW. (Please note this Working Group expresses no substantive views on the merits of such a change.)

2) Flexibility to introduce further General Service subclass based on load

The Working Group notes the large range that currently exists between customers in the General Service>50 kW class and the Large Use class (namely, 50 kW to 5,000 kW).

Several distributors raised the question of whether further General Service subclasses might be desirable to better reflect of cost causality (the discussion was at a preliminary level, since detailed information on cost causality was not available).

Distributors that have a Large Use class but do not have additional subclasses between this and the General Service>50 kW subclass may want to consider including one as part of their upcoming cost allocation study. Since interval metering is in place for all customers > 1000 kW per Code requirement (and at 500 kW for some customers), additional metering may not be required in all cases.

Some Working Group members asked if the Provincial load data to be collected by the Ontario Load Data Research Group could support the introduction of a further General Service subclass below 1000 kW.

The answer given was potentially “yes”, but further work would need to be done to appropriately group the thousands of General Service interval meters available to the Ontario Load Data Research Group.

Conclusions: The Working Group asks if the Board could give some comments on the possible introduction of a further General Service subclass, so that any Province-wide sample design can take this possibility into account.

3) If a distributor proposes to implement a new rate classification

Each distributor will propose a new rate class in its 2006 rate applications, that distributor must carefully decide if additional load research work is required at present.

There would generally need to be justification presented to the Board for the introduction of a new rate class or subclass. The clearest evidence would be a cost allocation study. For instance, if a distributor were interested in introducing a seasonal and/or low density residential subclass, the cost allocation study to be filed should present evidence that the group of customers in question had a cost profile significantly different from that of other residential customers.

When is separate cost allocation justification not needed for a rate grouping?

The Working Group requests clarification of the comments in paragraph 1.4 of the DRH that "a rate group is an arbitrary sub-set of the rate class". The view of the present Group, in contrast, is that a subclass should normally have full justification in the accompanying cost allocation study.

- The Group suggests the closest theoretical example of the above might be a class based solely on a different metering arrangement, such as residential time-of-use customers. For such a subclass, the costs allocated to it would be the same at non-TOU residential customers, aside from an amount for the extra metering.

Conclusions: The Working Group recommends that, generally, an LDC planning to seek approval for a new (or existing) rate classification should include this grouping in the analysis to be completed as part of the cost allocation study. It is requested the Board advise if any exceptions will be allowed (i.e., rate groupings for which separate load and cost allocation results will not be required).

4) If the Board or an intervenor seeks a new rate class once the cost allocation study is underway

If the Board or any intervenor requests the introduction of a new rate class in the 2004 generic hearing or in the subsequent LDC-specific rate applications, the proper load data to support introduction of the suggested new rate class may not be available. The Working Group proposes two possible solutions:

- If the Board wishes extra load data to be collected starting 2004 for any group of customers beyond a distributor's existing rate classes, this must be clearly directed in the Board's forthcoming load data collection instructions.

- The generic hearing planned for later 2004 could focus on long-term rate design issues, and give instructions on new load data to be collected for purposes of rate design post-2006.

Boundary Issues

The Group cautions that the creation of a new rate classification often produces boundary issues. Specifically, once a new class is established, the challenge of potentially unfair treatment of customers on either side of the boundary is a legitimate and common concern. Therefore it is suggested significant differences in cost causality would generally have to be established before the introduction of a new rate class, with associated boundary issues, is warranted. The rate design consultations can address boundary problems further.

19. Sampling Of Major Rate Classes

A question the Working Group investigated was whether sample load data should be obtained from all major rate classes. In some load research studies, after all but one rate class is sampled (and the total system load is known), the load profile of that last class is determined as a “residual”.

Past use of “residual” class

In the course of its work, the Working Group located much useful former Ontario Hydro technical material. One such publication was Ontario Hydro Report R&U 79-5 entitled Load Research for Cost of Service Studies.[19] That Report indicated (at page 67):

> “Wisconsin Electric Power Company carried out an extensive program of load research in 1972 through 1974, with 500 residential customers, 50 commercial and all large industrial customers in the sample. As with the Hydro-Quebec program, larger general customers were treated as a *residual*, but were slated for study later on.” (italics added)

Use of a residual estimation method also occurred when Ontario Hydro did a “mock up” study of its rural system to test a proposed cost of service methodology. General class loads (G1 and G3) “fell out as the residual” (see page 51, Ontario Hydro Report R-86-17).

Initial views of working group

When the Working Group first discussed the issue, a majority suggested distributors be allowed the option of which rate class they may wish to leave as a residual (this was later narrowed, see below). The justification advanced by Group members for the use of a residual estimate was that if the load profiles of the total system and of all classes but one were accurately estimated, then the load profile of the residual class must also be accurate.

But some Group members wondered if an unfair amount of measurement error could potentially be placed on the residual class. It was thought that if the load profile of each class were independently estimated, then any difference between the sum of those estimates and the actual net system load shape could be allocated more fairly over all the classes. This hypothesis was later questioned because given “we know the total load with certainty, sampling all classes would not contribute further to minimizing the summation of mean square error of all classes”.

[19] That Report still makes useful background reading. For instance, the Report recommended that if several utilities undertook load data research, “it may also be advantageous to pool the data from all the load analyses, for the purposes of increasing the accuracy of the estimates” (page 7).

<u>*New proposal to limit the residual method to the more heterogeneous class*</u>

The Ontario Load Data Research Group's proposal is to make some use of the residual estimation technique for the GS<50 kW class, which is more heterogeneous than residential and hence harder to sample.

It should be recalled that interval meters for General Service customers cost considerably more than those used for residential customers. In addition, because the GS<50 kW class is so diversified (consisting of hundreds of commercial and industrial segments across the Province, spanning from retail stores and small commercial establishments to small offices and industrial shops), it is very difficult and uneconomic to survey each segment in sufficient quantity to estimate the load shape.

Technical defence offered for focused use of a residual estimate

An experienced Ontario load research specialist later offered the following technical defence of the idea of using the GS<50 kW class as the residual:

> **"**The proposed load research methodology does not sample from all classes. If there are n classes in a utility, samples will be taken in n-1 classes. The reason is that the total load profile of the LDC is known with certainty and having determined load profiles for n-1 classes, the load profile of the nth class can be computed residually.
>
> A relevant question to the extent of error allocated to the residual class. Suppose we examine the mean square error of the residual class. It can be shown that the mean square error of the residual class is the summation of the mean square errors of the other classes. (For example, if there are only two classes, the mean square error of the residual class is the mean square error of the sampled class.) One implication of the above is that if the objective is the minimization of summation of mean square error of all classes, then the goal should be to sample from the classes where the mean square error can be effectively minimized. In other words, choose the non-residual sampled classes as the ones where one can effectively and efficiently uncover the load profiles with the least error. That is, choose the sampled classes as 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."

The above represents a more detailed defence of the use of a residual estimate than that found in the literature reviewed, and it is asked the Board to carefully consider the merits of the new arguments advanced.

New load data now available for GS < 50 kW class

Because of the willingness of many Ontario LDCs to join the Ontario Load Data Research Group, that Research Group is pleased to report it now has a few hundred interval meters in the GS<50 kW class at its disposal.

Therefore the final plan of that Research Group is to use the new data collected from these meters to refine and supplement the estimate for the GS<50 kW grouping.

The Ontario Load Data Research group will also investigate if past Ontario load research data can be of some assistance.

Conclusions:

The Ontario Load Research Group does not propose to use a pure residual estimate for any rate class. As a result, the load profiles to be developed for members of that Research Group will be based on some new load data from all of the major rate classes.

The Working Group suggests the Board decide if all LDCs in the Province should be required to develop load profiles based upon at least some new load data from each major rate classifications (as now proposed, for example, by the Ontario Load Data Research Group).

Given the modest recent level of load data research in this jurisdiction, and the technical difficulties in accurately measuring the load profile of the GS< 50 kW classification, the Ontario Load Data Research Group respectfully suggests its proposal for partial use of a residual method is “appropriate and practical” (as per the Board’s October 28, 2002 correspondence).

20. Deemed Load Profiles

The Working Group understands it is common to determine the load profiles for some rate classifications through use of a deemed load profile.

Re Street lighting

Individual distributors have recently had their street lighting deemed hours of use approved by the Board.

It is recommended that the above figures be used when each LDC calculates a deemed street lighting load profile for cost allocation purposes.

Re Sentinel lights

The Working Group recommends it is reasonable to apply the deemed street lighting load profile to sentinel lights.

- In past Ontario Hydro practice, the cost justification for sentinel lighting was minimal. The rates for sentinel lights were simply set at 110% of the street lighting rates. The upcoming generic hearing will give the Board the opportunity to revisit whether rates between the two uses should be the same or different.

Re Unmetered scattered loads

Unmetered scattered loads are loads, such as cable amplifiers, bus shelters, telephone booths, traffic lights, etc., that are sufficiently small and predictable in their usage and for which it is not cost justifiable to install a meter. These loads are billed on a flat consumption, estimated either on the basis of a load study or from the connected load. While some distributors have a special rate class for these loads, most bill them at the General Service<50 kW rate. Another difference among distributors is the classification of lighting loads such as park lighting or bus shelters. It is understood some distributors include these in the Sentinel Light class, whereas others treat them as unmetered scattered loads.

The present Report will address the load data issues for scattered unmetered loads; other issues (such as treatment for cost allocation purposes of joint use of poles and street lighting) will be treated in a subsequent Report.

A preliminary policy question is should these loads be a separate grouping (as in current rate orders), or be incorporated in the broader GS<50 kW grouping.
Such loads were not treated separately in the past, and one may ask the justification for distinguishing this group separately from other GS end uses?

On balance, however, the Working Group recommends that unmetered scattered loads be considered separately, where they continue to exist, in the upcoming cost allocation studies.

Calculation of deemed load profiles

By definition, scattered unmetered loads are not metered and hence the usual load sampling methods are not relevant

As explained in the AEIC Load Research Manual (see page 9-8), for such uses a deemed load profile is used:

> "Deemed profiles are pre-specified load shapes agreed to in advance, based on simple assumptions about hours of use and loads when in use. Commonly, this method has been used for unmetered loads, such as street lighting with predictable, essentially flat shapes.
>
> Advantages of deemed profiles are:
> - They are available in advance.
> - They are inexpensive.
>
> Disadvantages are:
> - The deemed shapes may have systematic errors.
> - It may be difficult to develop an acceptable basis for generating the deemed shapes."

Conclusion re Scattered Unmetered Loads

The Working Group recommends each LDC establish and verify a deemed load profiles for scattered unmetered loads (until such loads become individually metered).

The Working Group did not advance any generic suggestions on how to calculate a deemed load profile. One distributor thought it would prove relatively easy for each LDC to make technical assumptions about the profile of a known scattered unmetered load, but LDCs faced difficulties in confirming the operating characteristics of the actual equipment installed.

The important question of whether rates for these users should be set on a per connection basis was deferred to later rate design consultations.

21. Organization of Remaining Cost Allocation Consultations

The Working Group would like to share some suggestions for organizing the remainder of the cost allocation consultations.

Case Study of Data Utilization Methodology

The Working Group expressed strong interest in a case study to illustrate, and confirm for all stakeholders, the proposal to use the existing modeling software and expertise of Hydro One to generate LDC-specific (and weather adjusted) load profiles targeted at plus or minus 10% accuracy (at 90% confidence) from the data to be collected by the Ontario Load Data Research Group.

If the Board agrees to add this item to the agenda when the cost allocation consultations resume, Hydro One Brampton has agreed to be the case study.

Time lines re any new non-load data requested

When the consultations resume, it is expected any remaining potential data issues will be examined.

If distributors will be asked to collect any other non-load data (e.g. further financial information) starting January 1, 2004 for use in the upcoming cost allocation studies, it is recommended that the Board issue appropriate directions sometime in November 2003 (so distributors can have time to organize the collection of the required new data).

The Working Group would note that its second Report (on non-load data issues) may not be completed by November, and therefore some type of interim update may be necessary to enable the Board to issue any further directions by then. Note more lead time may be necessary to gather some types of new data.

Cost allocation case studies recommended

In order to provide practical illustrations of the policy matters under discussion, the Working Group was in strong agreement to recommend that some cost allocation case studies be conducted.[20]

- Enersource Hydro (Mississauga) has volunteered to be a large-size distributor case study.
- It is expected several distributors are interested in being a medium-sized distributor case study.
- A distributor with a customer base of between 5,000-10,000 customers is suggested as the third case study.

It is suggested the case studies run alternative scenarios (e.g. minimum system versus modified minimum system) to test the sensitivity of results to varying assumptions. It is believed such information will benefit all the stakeholders, and the Board, when these challenging technical issues are addressed at the upcoming generic hearing (and it may well assist in early resolution of some matters).

[20] Ontario Hydro did several case studies in the 1980's (e.g. Guelph, Milton, etc.) of a proposed CoS methodology, which the present Group still found useful to review. Also, it was noted that a numerical case study was undertaken in a past Board consultation, and that the APH has numerical examples for the benefit of readers.

22. Future Organization of Load Research in Ontario

The Working Group understands that since the former Ontario Hydro terminated active load research in the early 1990's, no one has been pursuing large-scale load data collection in a systematic manner in Ontario. The material the Group reviewed suggests, however, there will be a future need for greater local load research.

Most regulators require that the load data used for cost allocation purposes be updated from time to time.

Load data has further potential uses at the rate design stage.

- "Specific appliance end-use rates (such as heat pumps or thermal storage), time differentiated or not, also require load data research for their design." (Page 8-3 to 8-5, Load Research Manual.)

Load data has potential use if and when transmission rates to end-use customers require cost allocation to apply by rate class. The Board should be aware that any further load data required will cost LDCs further expense and time and may delay implementation of any change to transmission rates, unless the load data may be used for transmission rate design.

Any future group looking at Demand-Side Management implementation will likely have an interest in ensuring Ontario has a viable load research program.

- "Load research data are also used to evaluate the success of special rates as load management tools." (Page 8-5, Load Research Manual.)

As up-to-date load data become available, it is anticipated distributors themselves will make use of such data to help them obtain further operating efficiency gains:

- "As an example, distribution engineers determine optimal line transformer sizing at the time of installation and monitor existing transformer loadings to anticipate overloading problems. Their primary goal is to use the transformer size that minimizes purchase and installation costs, anticipated losses, and transformer burnout risk (caused by overloading). Toward this goal, load research data can be used to estimate loadings on distribution transformers." (Page 8-7, Load Research Manual.)

Establishment of an Ontario Centre of Excellence for Load Research

The Working Group anticipates that the industry and others (OEB, IMO, Ministry of Energy) will likely benefit from on-going load research to support a variety of future initiatives aimed at improving the overall functioning of the Ontario electricity market.

Since it is costly for distributors to separately conduct load research work, it would make sense to establish a load research centre to coordinate future load research work to be undertaken in Ontario. The Working Group accordingly recommends that public authorities explore the establishment of a Centre of Excellence for Load Research at an Ontario university to help undertake load research work on an on-going basis, either funded publicly or co-funded with distributors.

By way of illustration, the Working Group believes such a Centre would be useful in designing and implementing any further load research needed in conjunction with demand-side management proposals that may be forthcoming.

A Centre supporting local technical expertise and dissemination of information to stakeholders could also provide the means for ensuring Ontario follows North American “best practices” in the area of load data collection and utilization.

Finally, given the wide uses of good quality load data (such as helping to shift peaks), a funded ongoing load data research program could be viewed as an integral part of the mature functioning of the retail power market in Ontario.

APPENDIX "A" - Embedded v. Marginal Cost Allocation Studies

General Background

There are two basic types of cost allocation studies (also commonly known as cost of service studies). Embedded cost allocation studies deal with the costs of existing plant and operating expenses. Marginal cost allocation studies attempt to calculate how the future costs change with a change in demand, the number of customers or (where appropriate) the amount of energy used.

Marginal cost allocation studies do not usually go through the steps of functionalization, classification and allocation in the same way as embedded cost allocation. Instead, they rely more on engineering calculations and hypothetical studies.

When the time period or the quantity is small enough so that additional plant is not needed, the resulting change in costs is known as short-run marginal cost (note a simple small spike in demand may have no effect on the costs of the distribution system in the short run). When the time period for which the study is performed is longer, change in demand and energy requirements will generally be larger and additional plant may need to be built. The results are referred to as long-run marginal costs. Because the changes over longer periods are larger, they are often called "incremental costs" rather than marginal costs and are often simulated by adding a fixed amount of demand etc.

Application to distribution systems

To understand which costing approach is best utilized for a cost allocation study for a distribution system, one must first understand some basic operating and design principles. The major cost components associated with distribution systems are distribution lines and transformation. From an operating and design perspective, distribution systems must be designed to allow for flexibility of operations in order to accommodate transient conditions such as outages.

Distribution feeders are designed in a manner that allows for additional feeder capacity availability on each feeder over and above the feeders' normal supply requirements. This additional capacity is available in order to ensure that the load, associated with the loss of any one feeder, can be transferred to other feeders without exceeding their maximum loading capacities. Transferring load from the downed feeder reduces customer outage times while their main feeder is repaired.

Distribution lines and equipment are constructed in a manner that allows them to supply many customers. In most cases, large customers excluded, these facilities cannot be constructed to supply any one individual customer. The physical characteristics of distribution facilities are conducive to supplying many customers at once. It would be economically unviable to construct a distribution feeder for one residential customer and upgrade that distribution line every time an additional customer was connected to it.

Because these feeders have some flexibility in their loading capacities, in most cases, the addition of one customer will not substantiate the construction of a new feeder or distribution sub-station. It would be impractical to isolate the costs associated with the addition of a new customer, as they are unlikely to utilize the whole feeder. The construction of a new feeder also benefits all of the existing customers in the distribution company's territory due to the additional capacity. In general, the marginal cost approach would not be applicable to distribution systems as they are not designed based on a marginal approach.

Embedded Cost Allocation Studies Recommended for Ontario

The embedded cost approach allows a distribution company to use proven historical financial and loading patterns to formulate a cost of service study. Conversely, a marginal cost approach must rely on forecasted customer and facility growth. The Working Group notes page 54 of the OEB's 1979 H.R. 5 decision stated in this regard: "We have concluded that the judgment decisions involved in the proposed substitutes for marginal-cost pricing are more numerous and more complex that those associated with accounting costs." The present Working Group sees no reasons to change that conclusion.

The knowledge base of the various 90plus Ontario distributors may vary from LDC to LDC. The methodology associated with the embedded cost approach can readily be standardized to accommodate this diverse group. If a marginal cost approach were used, each distributor would have to have their planners forecast their customer and facility growth over a specific time period. Economic assumptions would have to be used in these forecasts. This may lead to inaccurate results for some distributors. The embedded cost approach, in contrast, allows all LDCs to use proven historical data.

The Working Group recommends that use of an embedded/average cost allocation approach will prove easier and produce more consistency in results.

The following practical considerations provide further support for the above recommendation:

- It is understood that Ontario natural gas distributors have filed embedded cost allocation studies.
- Various Ontario electricity utilities have gained practical experience with embedded CoS studies since the 1980's onwards.
- The MEA has commissioned various embedded CoS models over the years (the last one was examined by a 1998-2000 Task Force).
- The current Distribution rates are the result of the unbundling of existing bills, which in turn were calculated using rates based on average costs.

<u>APPENDIX "B" - Alternative Methods for Allocating Demand-Related Distribution Costs</u>

The AEIC Load Research Manual provides the following definitions:

<u>Coincident Demand</u>: "The demands of any appliance, customer group, class, or system within a specified period (day, week, month, year) at the time of the system peak for the same period."

<u>Noncoincident Peak Demand</u>: "The sum of the individual peak demands of the components of the group, class, or system within a specified period (day, week, month, year), regardless of time of occurrence."

<u>*Issue 1) Use of NCP v. CP as default demand allocator*</u>

To allocate demand-related distribution costs to customer classes, a majority of the Group recommends the use of non-coincident demand as the common, Province-wide "default" demand allocator in the upcoming cost allocation filings

Reasons are:

- Coincident demand is usually used to allocate generation costs.
- In general, distribution facilities are the facilities that are closest to the customer and are sized to meet the individual customer's demand and not the aggregated demand of many customers.
- Non-coincident demand is relatively easier to measure, track, and understand than coincident demand. To ensure representative treatment, one would need to collect coincident demand data on a facility-by-facility basis.
- Using non-coincident demand would better match cost allocation between customer classes with cost recovery from same customer classes. One would not bill customers on their coincident demand, since customers who are able to determine their demand consumption would only know after the fact what their billing demand would be for billing purposes.
- 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's peak, e.g., seasonal customers.
- Customers would have better control over their non-coincident demand than over their coincident demand.
- In general, non-coincident demand is more stable than coincident demand and easier to forecast.
- Most of the customers in an LDC are residential customers and it would be more difficult to determine coincident demand for customers that do not have demand meters. Non-coincident demand could be derived from load research or typical load profiles.
- Development of DSM initiatives may be easier if the starting basis is non-coincident peak demand.

To conclude, the Working Group would recommend use of CP in the upcoming cost allocation studies in specialized circumstances only (see section 5 of report for details). It is expected some form of NCP (see discussion below) would be more appropriate for the bulk of Ontario distributors.

Recommendations re Class and Customer NCP

The Group learned there are two different types of Non-Coincident Peak:

1) Class NCP. This is based on the maximum demand of each customer class.

2) Customer NCP. This is based on the sum of the individual maximum demands of the customers in each class.

The Working Group recommends both be collected, as each is best applied in certain circumstances when completing the cost allocation studies.

The Group's conclusions on this point are the same as those adopted in the NARUC Cost Allocation Manual (page 97, 2nd Edition): "Customer class non-coincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of the distribution facilities."

Issue 2) Merits of Various Types of NCP Allocators[21]

Distributors build their distribution systems to accommodate the highest peak demand of the year. Once built, the cost of that distribution system does not materially change from one month to the next.

The 1NCP method allocates distribution system costs to customer classes in proportion to the amount that each customer class contributes to that annual non-coincident peak demand load. The major distinction between 1NCP and 12NCP is that the 12NCP method allocates those costs in proportion to the average of 12 monthly peak loads, thus diluting the peak demand costs.

Purpose

The purpose of the 1NCP method is to more accurately direct costs to customer classes that cause the annual peak load upon which the building of the distribution system is predicated.

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[21] The Working Group was fortunate to locate a study by the Rates Structure Department of the former Ontario Hydro (RS-92-6: Volume 1, September, 1992) that evaluate 5 demand allocation methodologies (1CP, 1NCP, AED, 12CP, 12NCP) against 14 selection criteria (no free ride; 100% load factor rule; recognizes load factor; recognizes demand diversity; stability; undue discrimination; impact; comprehension; consistent; equitable; efficient; purpose; flexibility; minimizes calculations). This was the most sophisticated discussion known to the group.

The purpose of the 12NCP method was to recognize that generation facilities are unavailable during regular maintenance shutdowns and that the loss of revenue during those shutdowns may be compensated, to some extent, through savings in fuel costs. In an unbundled rate structure, costs related to generation are allocated to the cost of energy.

A distribution system sees no savings during shutdown or breakdowns. Therefore, in an unbundled rate structure, the rationale for staying with 12NCP is customer impact.

Equitability

One of the most significant causes of peak electricity demand in Ontario is the summer air conditioning load. Allocating the costs over 12 monthly peaks, as in the traditional 12NCP method, unfairly penalizes those customers who have no or low air conditioning loads or who otherwise keep their demand load relatively even throughout the year, as industrial customers tend to do. Whereas, allocating the costs in accordance with each customer's highest peak demand of the year, that is 1NCP, arguably more accurately reflects the cost of building distribution plant to accommodate that demand.

In other words, due to the fact that distribution systems experience high summer and winter peak demands, 12NCP is not the best method because it allocates demand costs over an annual period of time that can result in the reduction or dilution of demand costs of customer classes heavily contributing to sharp maximum system peak demands.

Impact

The customer impact of 1NCP is that it assigns a higher burden of distribution system costs to residential and commercial customers who typically have a high peak demand relative to their average demand and assigns a lower burden of distribution system costs to industrial, street lighting and unmetered scattered load customers.

Stability

Stability in the allocation of costs from one year to the next is better with the 12NCP method because a single annual peak is diluted over the average of 12 monthly peaks. Whereas with the 1NCP method, any change in weather pattern from one year to the next will be reflected in a proportionate change in the allocation of costs.

To offset the problem of a single event affecting the allocation factors for an entire year, a modification to the use of the single non-coincident peak hour per year may be made, as is often made with the single coincident peak (1CP) method. For the purpose of stability, distributors may move from using one peak interval per year to a number of peaks. For example, a weighing of 2, 3 or 4 highest peak demands (referred to as 2NCP, 3NCP and 4NCP in these discussions) could be substituted for the single peak hour. In the 2NCP method, both the summer and winter peak or two summer peaks would probably be captured and the dilution would be very minimal; that is, much less than in the 12NCP method.

Calculations and Comprehension

The 1NCP method is slightly easier to understand because there is only one annual peak load and therefore no need to average 12 monthly peaks.

Other Criteria

Most other selection criteria between 1NCP and 12NCP are considered to be relatively equal.

- Report RS-92-6 (see page 38 of Volume 1) ultimately recommended 12NCP should be the “allocation method used in the regulatory process for the cost of service model”. The Group understands the former Ontario Hydro accepted this recommendation.

- The present Working Group believes any concerns about the pure rate impacts of moving from the inherited system, which was based on 12NCP, to one that uses 1NCP as the common default, should be addressed as a rate mitigation issue at the rate design stage. But the Group did agree that concern over the stability of cost allocation results was a valid technical reason for some LDCs to desire the option of using a NCP method aside from 1NCP.

Conclusions: Combining flexibility and consistency

The decision as to which demand method allocation method a given LDC should follow can be made later, since 12 months of interval load data will be gathered and this will support all of the main demand allocation methods (for example, CP, 1NCP, 12NCP). A dissenting Group member preferred this approach overall.

The Working Group believes that 1NCP is generally the preferable allocation method for distribution systems. But a case for using other versions of NCP exists. Given the wide variety of circumstances faced by individual LDCs, the Working Group would recommend the Board allow an individual distributor to use another method (CP, 2NCP, 3NCP, 4NCP or 12NCP)[22] in its upcoming cost allocation study, provided that: 1) the LDC explain why the alternative method is more suitable to its specific circumstances, and 2) such an LDC also run its cost allocation model using 1NCP (thus providing a sensitivity analysis).

The ultimate result of these recommendations are that the Board, and stakeholders, can compare results across the Province based on the same demand allocation methodology (namely, 1NCP), and an LDC will provide a sensitivity analysis if it wants to utilize another demand allocation methodology (e.g. CP or 12NCP).

[22] Note there are a variety of other demand allocation methodologies mentioned in the reference materials, but the Working Group recommends the cost allocation filing instructions set out a limited number of approved demand allocation options that are most likely to be of relevance to Ontario distributors. For instance, the Working Group understands that the widely-known Average and Excess Method would not be applicable to an unbundled distributor.

APPENDIX “C” - Interval Metering Options

The Working Group benefited from specialist advice on interval metering options.

Interval Metering Technology provides both the quantity and time of electricity consumption, allowing customers to make better decisions on when they can more efficiently use energy within their homes and businesses.

When looking at interval metering, the major stumbling bock is not how one meters such loads, but how the interval data is retrieved, at what frequency (time), and how much does the technology cost.

There is no one remote technical solution to fit all LDCs’ diverse demographics and geography. Distributors will instead search for a best-of-breed for automation, which covers a wide range (hybrid) of network topologies. Two-way fixed wireless covers more densely populated areas well, while power line carrier (PLC) is more appropriate for less urban and rural areas. Other technologies such as drive-by RF, PSTN and one-way RF may fit in certain areas as well.

Feature	Drive-by RF	One-way PLC or One-way RF	PSTN	Two-way PLC	Two-way RF
Energy Consumption	*	*	*	*	*
Tamper Detection	*		*	*	*
On-demand Reads		*		*	*
Outage Detection		*	*	*	*
Connect/Disconnect				*	*
Load Curtailment				*	*
15 Minute Peak Demand			*	*	*
Voltage Level				*	*
Interval Data			*	*	*
Network Pre-pay					*
Time-of-use			*	*	*

Technologies Currently Available

Option 1: Singlephase version of a typical commercial type meter as used by most utilities today

It was suggested this option would be the most cost effective option for a short-period survey (but not for a full-scale Residential Interval Metering deployment).

These meters have enough memory to hold well over 60 days of single channel interval data. Meter's load profile data could be easily uploaded monthly, through a standard handheld, on the meters normal read schedule. Estimated Cost**:** Meter: Up to $400.00. Read Cost: $0.45.

Option 2: Telephone Technology

It was suggested this option would be cost effective for full-scale deployment of residential interval metering.

Telephone-based meter modules deliver Automatic Meter Reading ("AMR"), Interval Metering, outage detection and restoration functionality for residential electric meters. These dial-inbound systems use field-proven DTMF data transmission technology over existing wired and analog cellular telephone networks. They have been specifically designed to unobtrusively share the utility customer's phone line with "polite" technology. Key applications include providing reads, interval data & outage / restoration information from customers that are dispersed over a wide geographical area or where advanced meter reading functions are desired at selected locations.

Using these modules, utilities also have the flexibility to implement demand, and hourly pricing, along with near real time outage and restoration notification, at the metering sites where it's needed. Moreover, the type and quantity of data collected can be easily modified as requirements change. Reading frequency and read dates are completely programmable from the head-end; the system can read meters once a month or as often as every 15 minutes. A telephone-technology equipped meter can provide consumption data for each 15-minute increment even when read every 4 days.

Estimated Cost: Meter & Module: $200.00. Read Cost: $1.00 per meter per month (outsourced to contractor). Read Equipment and Installation if reading done in-house: $70,000 (approximately).

Option 3: Radio Technology

It was suggested this option would be cost effective for full-scale deployment of residential interval metering.

Radio meter modules deliver Automatic Meter Reading (AMR) and Interval Metering for residential electric meters. These modules operate in the 900 MHz unlicensed frequency. The modules (ERT) are manufactured by Itron and fit all manufacturers residential meters. A system consists of an ERT equipped meters, concentrators (quantity depends on geographic area and meter volume) and a host processor that is used to manage the system. Meter reads and interval data is transmitted to a collection concentrator that is mounted to a light pole within 500 feet from the ERT. In addition to the distance limitation, a concentrator can handle up to 2000 ERT equipped meters within its cell. The concentrator communicates to the host system via dial-up, cable or fiber connected broadband ISP.

Estimated Cost: Meter & Module: $150.00. Concentrators: $4,000.00 each. Read Cost: $1.00 per meter per month (outsourced to contractor). Read Equipment and Installation if reading done in-house: $50,000.00 (approximately).

Appendix "D" - Alternative Dates for Commencement of Joint Load Data Collection

The Ontario Load Data Research Group has set out a range of dates by which its members could start collecting load data, which the Working Group believes to be representative of the likely commencement date for any Province-wide load data collection initiative.

The information available to the Working Group is that if everything is as planned:

- meter ordering takes up to 10 weeks,
- meter installation takes up to 8 weeks, and
- meter testing usually takes 4 weeks.

Note that if approval is received at a late date, then the ability to file CoS studies in 2005 on a timely basis may be affected (given the long time lines involved).

Schedule	**Optimistic**		**Pessimistic**
OEB Decision	September 15, 2003	September 30, 2003	October 7, 2003
Meter order	November 15, 2003	December 15, 2003	January 7, 2004
Meter installation	December 15, 2003	February 15, 2004	March 22, 2004
Meter testing	January 1, 2004	March 15, 2004	April 22, 2004
Start collecting data	January 1, 2004	March 15, 2004	April 22, 2004

If time constraints were not an issue, starting load data collection by January 1, 2004 is ideal, in order to collect load data and financial data for the same calendar year. (Note whether a past or future test year will be used in the "going-in rates" filings was deferred for later discussion in the consultations.)

It is important to understand that the optimistic January 1, 2004 target starting data allows only 8 weeks for ordering meters and only 4 weeks for meter installation, which may not be feasible for LDCs that have to install a substantial quantity of meters. The optimistic scenario allows only 2 weeks for meter testing, which assumes that no problems will be encountered with the retrieval of load data. The optimistic scenario also requires that the OEB approve the plan on an expedited basis and that no major changes are requested. Given the stringent assumptions required, the Research Group considers a January 1, 2004 starting date to not be feasible for its members.

APPENDIX "E" - MV- 90 Overview

The Working Group benefited from a specialist presentation on the features of MV-90, which is a Remote Data Acquisition/Processing software that incorporates some very robust Data Management Tools for Editing, Estimating and Reporting.

Unlike other proprietary metering software that is designed to interface with specific manufacturer hardware, MV-90 is "Multi-Vendor". MV-90 can be used to interrogate a number of different devices produced by a wide variety of manufacturers. Additionally, MV-90 is not restricted to Electricity-based products alone and can access many other devices dedicated to recording Water, Gas, Pressure, Temperature, Voltage, Current, etc.

There are several software packages on the market designed for remote data acquisition functions, but the MV-90 has been selected by the Independent Electricity Market Operator to perform those functions in the IMO-Administered Market. Having MV-90 allows LDCs to mirror the functions of the IMO including the incorporation of their VEE (Validating, Editing and Estimation) parameters within LDCs' own MV-90 operational procedures. Not only does this allow a distributor to literally mirror and validate IMO data, it follows the thrust of the Ontario Energy Board Distribution Code (revised November 1, 2000):

> 5.3.4 "A distributor's VEE process for data from MIST meters shall consider industry standards specified by the IMO in its VEE process for registered wholesale meters."

How it Works

MV-90 has a number of global "System Parameters" that must be established before the system will work at all. Having these parameters identified and established prior to installation is preferable.

Accounts or "Master Files" are created for each Meter or "Virtual Meter" that forms part of the operational cycle. This will include the creation of channel records, units-of-measures and appropriate multipliers. It is easy to get these wrong and it is recommended that entered values be checked with meter programming specifications and records of installation.

Automatic "Calling Cycles" can be established in advance and the "Task Scheduler" can be placed in unattended mode so that interrogations can be performed in the middle of the night when telephone activity is reasonable and calling rates are low. If an interrogation is successful and passes the VEE parameters, then reports, exports and uploads can be automatically scheduled.

System Configuration and Communications

MV-90 is generally configured for dial-out communications over a standard analog phone lines. Each MV-90 workstation can be configured for this dial-out function utilizing a maximum of two modems (one on each COM Port). Alternately the MV-90 user can elect to purchase the MV-COMM add-on module. This allows an I/O device to be installed on the MV-90 server allowing simultaneous communications of sixteen modems. Multi-Port serial boards can be added to increase this capacity incrementally. MV-COMM can be used for inbound communications as well as TCP/IP, RF, Digital Telephone (including Digital Cellular) as well as ARDIS. There are plans to have MV-COMM support a number of future technologies as well including both wired and wireless.

MV-90 can be purchased as a stand-alone system for small applications. However, in the new environment it is generally advisable to install a network version of MV-90 complete with a dedicated Server and Workstations. The Workstations can be configured for different functions to optimize the daily process. For instance, one Workstation can be dedicated to the process of reporting so that these tasks do not interfere with other Workstations that are dedicated to VEE processing, while yet another Workstation can be configured for ODBC uploads to the distributors mainframe/billing engine, etc.

Multiple Workstations with individual login/password combinations for each user can be used to control which Operators have access to which accounts, which Operators can schedule calls, perform edits, run certain tasks, remove tasks from the scheduler, etc. For instance the distributor's Technical Services Staff may be able to access those accounts within their jurisdiction on a read-only basis. They may run reports, print graphs and perform data analysis, but they are not permitted to add, change or edit Master and Data Files.

Conclusions

Not only should LDCs be aware of the initial cost of the MV-90 software, they must also take into account the cost of required hardware, plus on-going annual support and maintenance fees.

Although one can (and should) automate MV-90 as much as possible, the product does not run by itself. There are dedicated people with the expertise to work with MV-90 and its inherent nuances.

To conclude, MV-90 is a powerful data acquisition, processing and reporting software package that remains the system of choice in the 90% of jurisdictions through the world. Currently, it has been selected by the IMO as "the standard" in the Province of Ontario.

APPENDIX “F” - Alternative Sampling Techniques

In determining a suitable load sampling technique for the electricity distribution market in Ontario, the Working Group believes there should be two guiding principles:

1. The sampling technique needs to be reasonably representative of the target population.

2. The sampling technique should be achievable within the means of the average distributor in Ontario.[23]

Simple Random Sampling is the easiest sampling technique. In it, each unit of the target population has an equal chance of being included in the sample. But a relatively larger sample size may be required to attain the desired accuracy.

Systematic Sampling, both **Random** and **Centred**, involves the selection of every k^{th} point from a sample population. The count can start from a random point or at or near the centre of the first k units. A systematic sample is one of the easiest types of samples to draw and has better precision than a simple random sample, if the population exhibits a linear trend when ordered (for example, by magnitude of consumption). If resources are not available for sample validation, centred systematic sampling of an ordered population may be preferable to simple random sampling.

Stratified Sampling, both **Random** and **Centred**, of the target population may increase the precision of sample estimates or reduce the overall sample size required if the target population can be divided into groups called strata where the individual strata are more homogeneous than the overall population, as may be the case with electrically heated customers in a residential class.

Judgmental Sampling occurs when units considered to be representative of the population are selected or when certain types of customers are included in the sample. The disadvantage of judgmental sampling is that there is no method by which the reliability of any resulting population estimates can be calculated. The Working Group therefore does not recommend its general use.

Sample Size will determine the relative precision of the data. A minimum sample size of around 30-33 units per rate class or strata should be considered as a starting point. In practice, a minimum sample size of around of 40 is suggested to account for corrupt or missing data, refusals and move outs. The precise statistically-determined sample size will vary according to the characteristics of a distributor’s classes, and the design accuracy targeted.

[23] The Group notes the Board’s letter of October 28, 2002 advised “stakeholders are urged to consider what allocation methodologies are appropriate and practical, given the Ontario context and planned timelines identified”.

APPENDIX "G" - Select Cost Benefit Issues re Accuracy of Load Data

Many Working Group members expressed a general concern that the cost of the load data to be mandated for cost allocation purposes may, at some point, exceed the conceivable benefits to be realized in terms of better cost allocation results. But a full understanding of the issue should note:

- The Working Group received various U.S. materials that explained the benefit to the functioning of the electricity market as a whole from high quality load data. The Working Group did not consider its mandate to extend beyond the electricity distribution sector, and therefore others will have to assess the full benefits from updated load data.

- Even within the distribution sector, load data has other valuable uses beyond cost allocation that were not examined. (Ontario stakeholders may be interested in learning that the Virginia utility load data research group organized a seminar in May 2003, where invited experts explained various practical uses of load data, such as assisting with distribution system planning.)

- The Group understood it was to focus on generic principles applicable to all LDCs in the Province, and therefore the full cost of any specific load research proposal was not priced by the Working Group.

- In general terms, it is understood the out-of-pocket expenses of the Ontario Load Data Research Group will include purchasing, installing and reading around 600 additional residential class interval meters across the Province. Further expenses will be incurred for expert assistance in load sample design and implementation.

- Later, there will be an additional cost to process the Provincial data to generate LDC-specific load curves. If weather adjustments are required by the Board, more costs will be incurred by each LDC.

The standard North American publication, the AEIC Load Research Manual states (2nd Edition, at page 4-4):

> "The desired accuracy should be determined for the study. A design accuracy of +/- 10% at the 90% confidence level at the system and class peak time was specified in 1978 by PURPA for all major rate classes."

Since the PURPA targets were enunciated in 1978, there have been a number of major industry changes in various jurisdictions, such as the current separation of the commodity from transmission and distribution charges in Ontario.

Factors potentially impacting on desirable load data design accuracy in Ontario for cost allocation purposes

1. Load profiles are used to fairly allocate distribution demand costs incurred to serve several rate classes; but this step can be avoided by the extent to which a portion of distribution system costs can be directly allocated.

2. In addition to individual customer assignment, direct assignment may allow LDCs to assign distribution system costs to a cluster of customers who are supplied through a discrete set of facilities.

3. For Large User, Intermediate User, and TOU with interval metered classes, the load shapes for each class is known with 100% accuracy. For the remaining classes (residential, GS<50 kW, GS>50 kW, street lighting, and unmetered), the differences between class load shape will involve the proper allocation of only a portion of the distributor's total costs.

4. The commodity and transmission costs represent in excess of 80% of the value of what is delivered to the customer, leaving only 20% (or less) for total distribution costs. Consequently, the impact of the allocation of distribution costs is arguably significantly lower for the unbundled rate compared to the design accuracy specified by PURPA (which originated when commodity and distribution costs were bundled).

The above points suggest the desirable load data accuracy (from a cost-benefit perspective) should be based on the intended regulatory purpose for which the data will be used.

- Data cost versus benefit issues will arise at several places in the overall cost allocation project, such as: use of the residual method to estimate the load profile of a class; the merits of weather normalizing load data; should further subfunctionalization be mandated; development of a default categorization method.

Adopting PURPA figures as Ontario target

The Working Group recommends that the PURPA target should be adopted in Ontario as a reasonable balance between the cost and benefits of acquiring accurate load data. This means adoption of the PURPA accuracy figures (+/- 10% at 90% confidence) at the system and class peak time as the sample design target for Ontario load data research. Note a target should not be confused with a mandated result, which could impose the additional expense of targeting say plus or minus 5% design accuracy.

APPENDIX "H" - Potential Load Data Needs of Specialized Rate Classifications

The Working Group wishes to caution there can be linkages between the choices made in setting up the load data research and the rate classifications for which good cost causality data will be obtained.[24] To fully address overlaps between cost allocation and rate design, the potential load data needs for every rate classification must be assessed. This Appendix will focus on the specialized rate classifications. Any distributor having, or wanting to introduce, one of these rate classifications must clarify the load data needs. Guidance from the Board would be helpful to ensure consistency.

1) *"Seasonal" Distribution Rates*

The Working Group understands seasonal rates for intermittent use (e.g. for cottage owners) could be of interest to more than one distributor across the Province.

The Working Group recommends that distributors with seasonal rates currently in place (or wanting to introduce a new such classification) collect extra load data to prepare full cost allocation results for this rate grouping.

The Ontario Load Data Research Group plans to sample residential seasonal customers as part of its overall residential class sampling program. In the absence of Board direction, it is not anticipated more seasonal distribution rates will be introduced.

2) *Low Density Distribution Rates*

Some literature reviewed suggested customer density can drive cost causality, but the present Working Group did not examine the full pros and cons of the issue (for instance, the applicability of the "postage stamp" principle of rate design).

Any distributor currently having varying density rates within the same general rate class should prepare a full CoS justification for each density classification.

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[24] "It is natural to stratify along existing lines used for allocating common costs, but in addition one ought to consider stratification along lines that might be used in the future. Thus, if a group has a plausible claim to be considered for a special rate, then it should be designated as a stratum and sampled accordingly in the load survey." (Page 22, Ontario Hydro Report R&U 79-5, Load Research for Cost of Service Studies.)

The Working Group believes, however, that no new load data would be needed, since the distinctiveness of this class is based on costs, not load profile (the Board may wish to confirm this).

In the absence of Board direction on this issue, it is not anticipated there will be a broad desire to introduce more low density rates.

3) *Time of Use Distribution Rates*

It is understood that a few Ontario may LDCs retain Time of Use distribution rates (note TOU commodity rates are a different matter). This Working Group left for others to examine whether there is any valid rationale for TOU distribution rates.

It is requested the Board's upcoming instructions address treatment of existing TOU distribution rate classifications for purposes of load data collection.

For those LDCs that retain residential class TOU distribution rates, the Working Group believes no additional load data collection will be necessary, since it is assumed the customers will be interval metered already (affected LDCs should confirm).

One of the LDCs on the working group had a General Service TOU rate, but after unbundling this effectively amounted to a General Service>1000 kW classification. No special load data issues will arise if a distributor's General Service "TOU" rate customers are all individually metered (affected LDCs should confirm).

4) Single v. Polyphase Rates

It was suggested that distinguishing between single phase and polyphase service would more accurately reflect cost causality. (Note the present Group did not fully examine the pros and cons of the idea.) At least one rural distributor, and possibly a few other LDCs, currently do have a separate polyphase rate.

It is believed that additional load data is not required for a polyphase rate classification (Board may wish to confirm). It is understood, however, that additional cost data would be needed for the CoS studies, since the metering is more expensive for polyphase service.

5) *Retail Customer v. Standard Supply Service*

Some new rate classifications came into existence as a result of the competitive electricity marketplace and the requirements of the retail settlement code, and the potential load data collection needs of these should be addressed.

The Group believes the distribution system costs to serve a retailer customer should be similar to that of a customer on Standard Supply Service. The major differential occurs with respect to the billing and settlement costs, which are not load related and therefore will not affect load research requirements.

6) Embedded Generation

In general, an embedded generator should pay directly for the distribution infrastructure necessary to connect the generation to the LDC's existing distribution system. As such, normally there would not be a distribution charge (see DRC for details), and hence no cost allocation issue arises.

Note a separate question is the merits of a special "back-up" rate (to be used, for example, when a cogeneration facility is down for maintenance). This Group did consider how cost allocation studies could support such a rate.

The potential load data needs of a "back-up rate" are unknown at present (the Board may wish to deal with this in its upcoming instructions or leave such a specialized issue for separate consideration).

7) Embedded Distribution

A number of embedded distributors exist in the Province. If the host distributor has an existing special rate classification (the group was unsure if any LDC actually had a low voltage rate in place before Bill 210), the Working Group suggests that the cost allocation study to be filed by the host distributor support that rate. It is believed any needed load data would already exist since the embedded distributor would likely be individually metered.

8) Voltage-based Rates

The Group noted some cost of service literature suggests voltage-based rates may better track cost causality. Some members of the Working Group expressed tentative interest in the concept:

- A Group member thought a case could be made for a separate class below 5 MW connected at subtransmission voltage. (There is already a class for customers above 5 MW, and in most distributors they are connected at subtransmission voltage.)

- Another Working Group member suggested customers connected only at the subtransmission system could be considered a separate class. This is a specific situation involving customers who do not utilize the majority of the distribution system that is used by other customers. It could be worth exploring for LDCs greater than 20,000 customers that have more than 10 customers at less than 5 MW connected to the subtransmission system (either 44 kV or 27.6 kV).

The present Working Group deferred to the rate design consultations a full exploration of the pros and cons of voltage-differentiated rates. One Group member agreed voltage sensitive rates might be appropriate if a distributor has voltage-sensitive classes, but this potentially creates problems where a distributor decides to change the distribution system configuration and voltages after the customer's initial connection. Significant adverse impacts could result in such situations.

The present Working Group requests confirmation of what additional data would be needed to support the introduction of voltage based rates for Large Users. Large Users are individually metered already, but the load date may need to be differentiated by physical asset used (it is assumed this could be done later).

Adjusting specific charges within a distributor's Condition of Service is another way to address some of the underlying concerns. For example, reduce customer connection charges when connected to the subtransmission system from what they would be if connected to the distribution system.

9) Interruptible rates

The Group reviewed some trade literature reporting that a Michigan utility used its detailed load data research to assist in the designing of interruptible air conditioning rates that reduced peak load demands by 5%.

It appears this idea involves commodity rate design and therefore may best be explored by others (such as those looking into DSM initiatives).

APPENDIX "I" – Preliminary Issues List Cost Allocation Studies Consultations[25]

"Board staff have reviewed prior electricity distribution cost allocation methodologies used in Ontario and in other jurisdictions, and have developed the following preliminary list of issues requiring resolution. Set out below are those issues which Board staff believe merit early attention in the consultations (to commence in 2002), so that LDCs can start load data collection for the required cost allocation studies:

Traditionally, the average cost approach has been used for cost allocation studies in Ontario. However, the marginal cost approach is an alternative. What are the relative merits of each approach in the Ontario context?

The non-coincident peak approach is often used to allocate demand costs in cost allocation studies for electricity distributors. What are the alternative approaches? What are the relative merits of each approach? What impact would the choice of method have on different customer classes? Should one method be specified as the default in Ontario? If so, under what circumstances is it appropriate to allow or require an LDC to use another method (such as coincident peak)?

What type of load data should be collected? In answering this, consideration should be given as to the specific methodology to be employed (e.g. coincident peak versus non-coincident peak for allocation of demand to customer classes), since data requirements differ according to the approach used.

Traditionally, 12 months of load data is recommended for cost allocation studies. Is this appropriate for Ontario LDCs? What considerations should be taken into account?

In order to ensure adequate reliability of the load data gathered, what sampling methodologies are appropriate?

Is additional metering needed to collect the appropriate load data? Are there any practical constraints if additional metering is required?

The Distribution Rate Handbook presently recommends "achieving economies where possible through joint development of load data" (para. 1.4). How can joint collection of load data be best implemented?

[25] From Board's October 28, 2002 correspondence.

In addition to the above issues, others matters warranting attention include:

The “minimum system” approach, and modifications to it, have been used often in cost allocation studies to categorize distribution plant costs into demand-based versus customer fixed charge components. Alternatives to the “minimum system” approach exist. What are the other approaches, and what are the relative merits of the various approaches?

What year’s financial data should be the basis of the cost allocation studies? Should utilities be required or allowed to update these figures (i.e. use a forward test year)?

Should a range be established such that changes to rates in a class resulting from the cost allocation would not be implemented if they are within the range? If so, what is an appropriate margin of error?

Should any adjustments to rates based on cost allocation be phased-in, if necessary, to mitigate significant adverse rate impacts on specific customer classes and profiles? If so, how?

Finally, note that some rate design issues (such as number of rate classes), to be examined as part of the … going-in rate-setting methodology consultations and proceeding, may have an impact on the completion of the cost allocation studies.“

APPENDIX “J” – Cost Allocation Working Group Members.

Cost Allocation Working Group Members
(First phase)

Distributors	Representative
▪ Bluewater Power	Kathy Gadsby Ron LaPier
▪ Brantford Power	Heather Wyatt
▪ Canadian Niagara Power Inc.	Doug Bradbury
▪ Enersource Corporation	Ralph Amar
▪ Guelph Hydro Electric Systems	Jim Fallis
▪ Hamilton Hydro	Terry Karp Cameron McKenzie
▪ Hydro One	Mike Roger Stanley But
▪ Hydro One Brampton	Scott Miller
▪ Hydro Ottawa	Lynne Anderson
▪ London Hydro	Ken Walsh Dave Williamson
▪ Milton Hydro Distribution Inc.	Don Thorne
▪ Oakville Hydro	Gary W. Parent
▪ Thunder Bay Hydro	Cynthia Domjancic
▪ Toronto Hydro	Anthony Lam
▪ Veridian Connections	Laurie Stickwood
▪ Whitby Hydro	Ramona Abi-Rashed
▪ Woodstock Hydro	Ken Quesnelle

Distributors	Representative
Upper Canada Energy Alliance (Aurora, Innisfil, Markham, Newmarket, North Bay, Orillia, Parry Sound, Richmond Hill, Tay, Vaughan)	Jim Richardson Gaye-Donna Young

Advisors Representing Individual Distributors	
▪ Chris Amos	Chris Amos
▪ Barker, Dunn & Rossi	Paula Zarnett Neill Winger
▪ ECMI	Roger White Andy Bateman
▪ Econalysis Consulting Services	Bill Harper
▪ Elenchus Research Associates	Bruce Bacon
▪ Bob Mason & Associates	Bob Mason
▪ Regulatory Compliance Services	Mike McLeod Peter Ioannou

Industry and Consumer Groups	Name
▪ AMPCO	Ken Snelson
▪ Electricity Distributors Association	Maurice Tucci John Wong
▪ FOCA	John McGee

Ontario Energy Board	
▪ Board Staff	John Vrantsidis Neil Yeung

APPENDIX "K" - Specifics of Province-wide Proposal by Ontario Load Data Research Group

Membership

At present, more than 40 LDCs have expressed interest in participating in the Province-wide load research project, representing about 80% of total electricity customers in Ontario. These distributors are founding members of the Ontario Load Data Research Group:

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
Ottawa River

Northern Region
Chapleau
Hydro One
Kenora
North Bay
PUC
Sudbury
Thunder Bay
West Nipissing
Atikokan

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

Rationale for the Joint Study

The following reiterates why it makes sense for Ontario LDCs to work together on a cooperative load research project:

- Costs of collecting new load data on selected customers will be spread between all participating distributors.
- Sample size of load research for participating distributors will be smaller than if the distributor decided to undertake the load research sampling on their own.
- Distributors will be able to share the experience gained in collecting the load research data and will be able to learn from other participating LDCs with respect to the overall process.
- Presenting the information to the OEB as part of the 2006 Rate Submissions will be easier as many distributors will be using the same approach and the OEB will become familiar with the methodology.
- Distributors 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 distributors, as opposed to a distributor 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.
- Any legal or licensing concerns about load data sharing can be collectively addressed.

Proposed Load Research Methodology

The Ontario Load Data Research 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 class. The approach is best explained using the following simplified equation:

> Distributor total system load shape (minus) interval customers load shape (minus) deemed load profiles (minus) residential load shape (minus) General Service>50 kW (equals) General Service<50 kW load shape.

Where:

Distributor total system load shape is metered.

Interval metered customers are defined as including both large users and all intermediate users (individual LDCs should confirm the latter are <u>all</u> metered).

The residential class load research will likely require the use of 100 currently installed interval meters, and the installation of about 600 new interval meters randomly selected and stratified by: different regions in the Province, by distributor, and by different end-uses, including both urban and rural representation.[26] The end-use approach for sampling is used because such data is available, while needed information is not as easily available for the average consumption approach to stratification. The end-use approach is also preferred because it requires significant smaller sample size than the average consumption approach. Residential load shape will be analyzed in four end-uses: base load, electric heating, electric water heating, and air conditioning. Residential seasonal customers will be including in the load data sampling undertaken by the Ontario Load Data Research Group.

Preliminary review of existing interval meters owned by participating distributors shows that the number of available General Service interval meters is in excess of 4,000. It is anticipated these will prove sufficient to produce a load profile for the General Service>50 kW classification (expert advice will be sought on how best to use the available meters). It is also hoped that this huge sample will provide the basis for further analysis if the Board wishes to explore another General Service subclass (subject to confirmation). Due to the significant number of existing General Service interval meters, there may be flexibility to later explore, if desired, moving the General Service 50 kW boundary to 100 kW.

Street light deemed load shape should be based on OEB-approved hours of use. The same deemed load profile is suggested to be applied to sentinel lighting. Deemed profiles for unmetered scattered loads should be established and verified by LDCs.

The Ontario Load Data Research Group proposes to make some use of a residual estimation technique for the GS<50 kW class. According to the expert advice received, the sampling should focus on the rate groupings with the most homogeneity within the classes and with the most available and accurate information. The residential class is the class with the most homogeneity, and considerable load information is available on the General Service>50 kW subclass from the thousands of meters already installed. It therefore makes sense to choose the General Service<50 kW classification as the residual class. Note new load data from several hundred meters currently installed in the GS<50 kW classification will be used to supplement the residual estimate. (As mentioned below, the possibility of reasonably putting past Ontario load data to some use will also be explored.)

[26] Note one member of the Working Group who was not party to the Province-wide initiative was interested in the basis of the calculation that the proposed 700 residential class meters would be sufficient. However, this number is in the range used when the former Ontario Hydro undertook Province-wide load data research based on detailed statistical analyses by specialists.

Other Steps

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 analyses.

The load shape information resulting from new research (including residential and General Service customers) will be compared with existing available load shape information (see IMO web site). If appropriate, the Bayesian statistical technique will be used to make some use of the older data.

Sharing of Load Data

The Ontario Load Data Research Group plans to confirm with the OEB that sharing of load data within the participating group (40plus distributors) 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 distributors not participating in the original load research study group will be able to have reasonable access to the interval data information collected (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 LDCs.

Each Ontario distributor who acquires the Provincial load research data will be free to seek out any party to use the load shape data, along with other necessary information, to generate LDC-specific load profiles that meet the PURPA guidelines.

Hydro One has the software and expertise to do this task in a cost–effective manner. Their suggested method is as follows:

> To prepare LDC-specific load shapes, the Provincial load shapes resulting from the data acquired by the Ontario Load Data Research Group will need to be adjusted for weather (i.e. specific weather conditions affecting the LDC will be taken into consideration), customer mix (i.e. different types of customers and industry segments of the LDC will be taken into consideration), and heating and cooling equipment saturation (i.e. different equipment usage patterns of the LDC will be reflected in the load shape analysis). The end result for the LDC will be load shapes by rate class, using the latest load and customer information specific to the LDC.

The Ontario Load Data Research Group is prepared to undertake a case study of a specific LDC (Brampton Hydro) to confirm how the Provincial load data can be used to generate LDC-specific, weather-normalized load shapes for use in the cost allocation studies. The Working Group recommends this be undertaken as part of the consultations, so that other stakeholders can gain in depth understanding of the process.

If most distributors in the Province chose to have their LDC-specific load profiles prepared by the same party, then it is anticipated a bottleneck may occur. For this and other reasons, the Working Group suggests that the Board receive the cost allocation studies on a staggered basis during the later part of 2005 and early 2006.