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COST ALLOCATION REVIEW

Board Directions on Cost Allocation Methodology For Electricity Distributors

September 29, 2006

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Chapter 1

1. Introduction

1.1 Purpose of Report

This Report sets out the Board's common cost allocation methodology to govern the cost allocation review informational filings due from licensed electricity distributors starting in the Fall of 2006.

The Board released for comment a Board Staff proposal (Cost Allocation Review: Staff Proposal on Principles and Methodologies) dated June 28, 2006.
A letter seeking additional comment on three specific issues was sent out on August 21st, 2006. Comments were received on the June and August proposals from the parties listed in Appendix 1.1.

This Report provides the cost allocation methodology directions approved by the Board. A cost allocation review filing model and accompanying instructions, consistent with the Board's Directions, will be issued in October 2006.

Licensed distributors will be required to provide the cost allocation filings in accordance with the provision in their respective licences that require distributors to "provide, in the manner and form determined by the Board, such information as the Board may require from time to time".

1.2 Scope of the Review

The Chair of the Ontario Energy Board advised stakeholders in a letter dated March 9, 2005 that a cost allocation review would proceed and that the review would be based "primarily on the existing rate classifications and a limited number of rate design issues".

As indicated in the September 2005 Staff Discussion Paper, discussions on a number of topics are outside the scope of the present consultations, including smoothing of rate classification boundaries, substantial changes to the fixed/variable distribution rate philosophy, rate classification changes to current density, seasonal and polyphase rates, and new time of use distribution rates. Issues involving acceptable revenue-to-cost ratios, rate impacts and mitigation measures are also outside of the scope of the initial filing process.

As previously announced, Board Staff will be commencing a separate comprehensive study of distribution rate design. The “Electricity Distribution Rate Design Review” is scheduled to proceed in early 2007. Comments from that process, along with information from the current filings, will be considered when the Board decides how best to proceed on rate classification and rate design matters.

1.3 Preliminary Technical and Modeling Discussions

A Technical Advisory Team (see Appendix 1.2) consisting of stakeholders representing large, medium and small distributors, as well as ratepayer groups, was established and met to provide technical input on policy, implementation and modeling issues. In addition, public Technical Workshops (five in total) were held to update all stakeholders on the progress of this project.

The Board would like to thank all stakeholders for their extensive input to the consultation process.

1.4 Load Data Directions

Certain load data issues were examined in earlier consultations, which led to the Board’s 2003 Load Data Report and November 10th, 2003 Load Data Collection Directions. Further aspects of the load data requirements for cost allocation filings were addressed during the present consultations. A Staff proposal regarding rate classifications to be modeled, and associated load data requirements, was issued for public comment in May 2006. Additional comments were sought on one aspect in the August 21st letter. The Board has reviewed the stakeholder comments. The resulting Board Directions in these areas are incorporated in Chapter 2 “Rate Classifications for the Filings” and Chapter 3 “Load Data Requirements”.

1.5 Objectives of the Informational Filings

1.5.1 Common Cost Allocation Methodology

In this Report the Board has established a common cost allocation methodology for use by Ontario electricity distributors. To assist in the completion and review of the filings, certain default values will be incorporated into the filing model. Using a consistent methodology, along with various utility-specific inputs, the upcoming filings will provide the Board with the information required to undertake the cost allocation reviews.

The primary criterion in developing the cost allocation methodology is to follow sound cost causality. Secondary considerations include the availability and reliability of the data to support the exercise, as well as concerns of materiality, practicability and consistency.

1.5.2 Cost Allocation Information

The filings will provide the revenue to cost ratio, and rate of return, for each rate classification of a distributor. This information will document the extent of any inherent cross-subsidization between rate classifications.

1.5.3 Rate Classification Information

For the purpose of the cost allocation filings, the term "rate classification" will generally refer to any separate distribution rate class or subclass. Each rate classification will be modeled separately.

The filings will model the implications of the following potential rate classification changes**:**

- eliminating the legacy rate class known as "Time of Use", including placing customers currently in a GS>50 kW "TOU" rate classification into GS discrete demand range, GS Intermediate, or GS >50 kW classifications
- adding a new embedded distributor rate classification for all host distributors
- adding a new Large User classification where a distributor has a customer with a demand above 5,000 kW in its GS classification
- adding a common separate rate classification for unmetered scattered loads (the model will also calculate an appropriate metering credit where Unmetered Scattered Load customers stay within the GS<50 kW classification)
- adding a common separate rate classification for distributors serving customers with significant load displacement facilities (the directions will also address calculation of an appropriate credit or charge where load displacement customers remain part of a main rate classification).

For the bulk of distributors that used a historical test year in their 2006 applications, rate classification changes will be assessed using 2004 data. The filings should indicate if there is a significant change since that date which may impact rate classifications.

It is anticipated the results from the forthcoming separate Electricity Distribution Rate Design Review will be available when the Board considers implementation of any changes to current rate classifications (or other rate design issues).

1.5.4 Customer Unit Cost Information

The filing model will produce customer unit costs per month for each rate classification. To assist with reviewing the range of current fixed monthly customer service charges, the model will generate reasonable cost-based lower and upper end customer unit costs for each rate classification.

Along with the above unit cost data, other established rate design goals, which may include non-cost considerations, will be considered before the Board implements any changes to current fixed monthly customer service charges.

1.5.5 Alternative to Current Transformer Ownership Allowance

The filings will include a common cost-based alternative to the current transformer ownership allowance. New substation and secondary transformation ownership allowances will be modeled and other relevant costs will be gathered.

1.5.6 Filing Questions

This Report includes a number of Filing Questions that all distributors must answer, where applicable, as part of their filings. The responses will generate information useful on a variety of matters such as wholesale market participant costs and accounting treatment of certain key accounts.

Where a distributor is unable to answer a Filing Question, the distributor must explain the specific reason(s) for this.

1.5.7 Summary of the Cost Allocation Filing

In addition to filing a completed model, all distributors will be required to file an accompanying Summary of the Cost Allocation Review Filing ("Filing Summary"). The Filing Summary should include a section where the distributor's management adds any general comments regarding the interpretation of its filing results.

A distributor is asked to report in its Filing Summary if the use of the approved cost allocation methodology has led to any results that do not reasonably portray cost causality in its specific circumstances and, if so, to provide an explanation of such results.

1.5.8 Specialized Situations

This Report sets out a common cost allocation methodology that is intended to cover the great majority of the situations to be faced by a typical distributor.

There may be specialized situations for which the Report does not provide guidance. For instance, there may be a distributor that includes generation assets in its rate base, but this is expected to be rare and so allocation rules have not been prescribed in this Report.

Where a distributor discovers a situation not covered by the cost allocation methodology approved herein, it should follow sound cost allocation practice and provide an explanation in its Filing Summary.

1.6 The OEB Cost Allocation Filing Model

The OEB cost allocation review filing model and accompanying instructions are planned for release to all distributors shortly after the issuance of this Report.

All licensed electricity distributors are expected to submit a cost allocation filing.

At present, the Board anticipates that the standard cost allocation filing model can be used by all distributors except:

- Hydro One Networks Inc.
- Hydro One Remote Communities
- Distributors with generation assets in their approved rate base
- Distributors with zonal rates that are to be modeled in Run 1 and Run 2.

In the above cases, the distributor must create its own filing model.[1] Any other distributor wishing to use its own model must obtain Board approval prior to filing

[1] The Board's standard model will be made available for modification by those distributors who need to file their own model.

its model. Any distributor-specific model must be consistent with the cost allocation methodology outlined in this Report. If such a distributor finds it necessary to supplement or adjust the Board-approved methodology, a full explanation must be provided in its Filing Summary.

1.7 Model Runs to be Filed

Distributors will be required to submit a Run 1 and a Run 2 of the filing model. Run 1 will generally be based on the distributor's approved 2006 rate classifications including any approved interim rates. Special rules will apply to distributors that are merging with another distributor which will allow them to file a simpler filing if there is a strong likelihood that separate rate classifications will not be maintained.

In Run 2, the select potential rate classification additions and deletions identified in this Report must be modeled.

The model filing should generally remain "closed" (i.e. changes should not be made to the internal logic and organization) when used in Run 1 and Run 2. Any exceptions will be noted in the model instructions.

If a distributor makes any changes to the standard model during Run 1 or Run 2 (for example, where the methodology adopted in this Report does not cover some unique circumstance), an explanation must be included in the distributor's Filing Summary.

A distributor will be allowed the flexibility to model certain further items in an optional Run 3 filing. The eight permitted options are listed in Chapter 3.

Where a Run 3 of the model is filed, the Filing Summary must identify any changes and adjustments included in the Run 3 version submitted and include additional supporting explanation and documentation.

In some cases, the model allows for use of an alternative where better data is available. It is intended that if an alternative is used, it should be used in all runs of the model and supporting explanation and documentation should be provided in the Filing Summary.

1.8 Confidentiality of Information

If the input information to be used would result in the disclosure of personal compensation details of an individual utility employee, or the load profile of an individual utility customer, then that input information must be hidden in the version of the model filed. However, the resulting model outputs must remain public.

The above concerns would arise if an account contains the salary information of only one or two employees and there are no other costs included in the account to mask this data, or if there are only one or two customers in a rate classification for which load data in required.

In the above circumstances, the distributor must specifically hide the relevant input data in the model filed (as it is too difficult to build this as an automatic feature in the filing model). The filing instructions will provide further guidance.

The Board has considered parties' comments on this issue and has clarified the confidentiality provisions. The Board is of the view that the above confidentiality provisions are now sufficient and reasonable.

1.9 Filing Process

Distributors will be required to submit their cost allocation filings to the Board in one of the four following tranches (for details, see Appendix 1.3):

1) November 30, 2006

2) January 15, 2007

3) February 28, 2007

4) March 31, 2007.

Distributors are expected to work closely with their load data service provider to ensure that the required load data is obtained on a timely basis. To meet the filing schedule, distributors should start background work upon issuance of this Report.

The filing requirements have been designed taking into account the need for reasonably reliable results, as well as the efficient preparation and review of the filings. Additional background work (such as a utility-specific minimum system or PLCC adjustment) is not encouraged for these filings.

The cost allocation review filings will be made public.

1.10 Review of Filings

Following a review of the cost allocation filings by Board Staff, stakeholders will be provided an opportunity to comment on the results.

1.11 Potential Future Implementation in Rates

In light of the extensive effort given to this process and the Board's deliberations with respect to the appropriate cost allocation methodology, parties should expect that the Board will give significant weight to the methodology adopted in this Report when deciding upon specific cost allocation matters in future rate hearings.

After reviewing the results from the cost allocation filings, and considering the overall regulatory context including results from the forthcoming distribution rate design consultations, the Board will decide upon the priorities for, and timing of, any adjustments to future cost allocations, rate classifications or rate design.

Certain distributors may be directed by the Board to address specified matters in future rate applications. The earliest potential implementation date for new rates following the review is most likely May 2008 when certain distributors will file full cost of service rate applications.

Chapter 2

2. Rate Classifications for the Filings

This Chapter provides Directions on the rate classifications to be modeled in Runs 1, 2 and 3 of the cost allocation filings.

2.1 Background

When establishing the scope of the cost allocation review, the Board decided to base the review primarily on the approved 2006 rate classifications. These are to be incorporated in Run 1 of the filing model.

The Board also decided to gather information on a limited number of rate classification changes. These will be incorporated in Run 2 of the filing model. The upcoming filings are of an informational nature and will not result in any changes to rate schedules at this time.

Distributors will be allowed the option of filing a Run 3 of the model to provide information on certain additional rate classification changes proposed by the distributor, providing suitable supporting data is provided.

For the cost allocation filings, the term “rate classification” will refer to any separate rate class or subclass. There will be two cases (Unmetered Scattered Load and Load Displacement Generation, for most distributors in Run 1) in which separate load data will not be required as the customers will remain part of another main rate classification, but a special cost methodology will be modeled to develop an appropriate credit or charge.

If, in the future, a distributor receives approval to create a new rate classification, stakeholders have suggested that changes in the treatment of Retail Transmission Service Rates should also be discussed. The Board notes this helpful suggestion and will consider the matter further following the review.

2.1.1 Modeling

The OEB cost allocation model includes the rate classifications common to the bulk of distributors. The model to be issued will include space for several additional utility-specific rate classifications.

2.1.2 Merging Distributors

Separate rules (see Chapter 3 for details) will apply to distributors that have merged and there is a significant prospect that separate rate classifications will not be maintained. Where applicable, separate zonal rates (defined below) will not need to be included in Run 1 or Run 2 of the filing. All distributors who have undertaken mergers are requested to review these rules.

2.2 Run 1 of the Filings

Run 1 of the filings should generally reflect the distributor's approved rate classifications, including any rate classifications approved on an interim basis. Distributors should consider the items listed below when completing Run 1 of the model.

2.2.1 Embedded Distributors

For Run 1, the distributor should model its currently-approved rate structure. If the approved charge to an embedded distributor is represented as a separate rate classification in the 2006 rate order for the host distributor and the approved rate is different than the approved rates of any other rate classification, then it can be generally assumed that the embedded distributor has a separate rate classification and this should be modeled in Run 1.

A distributor could be providing service to an embedded distributor but be charging standard rates for this service. In this case, these customers will be considered to be in the standard rate classification for Run 1. For Run 2, these customers will be grouped in the separate embedded distributor rate classification.

2.2.2 Unmetered Scattered Loads ("USL") in Run 1 and USL Metering Credit

Certain customer loads have traditionally not been metered by most distributors. Specific examples include such loads as: bus shelters, phone booths, CATV amplifiers, pipeline and telecommunication cathodic protection devices, sewage flow monitors, heaters for sewage flow monitors, traffic lighting and traffic control equipment on the street, billboard lighting, sign lights, highway cameras, city traffic cameras, general city monitoring cameras, railway crossing signals, and decorative seasonal lighting. The 2003 consultations suggested that a few distributors differed on the scope of uses included in USL versus other rate classifications.

For the purpose of the cost allocation filings, the definition of USL underlying the distributor's 2006 approved rates will be applied.

Prior to unbundling and developing the service charge and volumetric rate structure, USL paid for energy on a usage basis consistent with those customers classified as General Service. With unbundling, in most cases each USL connection was charged a service charge. During the process of developing the 2006 EDR Handbook, certain parties suggested that charging the same service charge as a General Service <50 kW customer for each connection was unfair.

During the 2006 EDR stakeholder consultations, a solution was developed that, pending detailed cost allocation studies, distributors that bill USL customers the GS < 50 kW monthly service charge on a per connection basis would be required to reduce the monthly service charge by 50%. Many distributors received 2006 rate orders based on this special methodology.

It appears certain aspects of the costs of serving these customers are reasonably distinct, and two approaches will be adopted in the filings towards allocating costs to Unmetered Scattered Load customers:

i) treatment as part of the GS<50 kW rate classification, with directions to gather information to model USL Metering credit unit costs; or
ii) treatment as a stand-alone USL rate classification, with separate load data requirements and separate allocation of demand and customer-related costs.

While USL charges are generally shown on the approved 2006 EDR rate orders as a separate item, there was often no full underlying cost data supporting the rates. Therefore, for the purpose of Run 1 of the cost allocation filing, distributors should carefully consider the underlying substance of their current USL rates. If the rate was set based on the special 2006 EDR methodology, approach i) should be followed. This approach is expected to apply to most distributors in Run 1.

The Filing Summary should include an explanation if the distributor wishes to use approach ii) for Run 1 (for example, where a distributor did detailed cost analysis prior to 2006 rates to support a separate USL rate classification).

2.2.3 Load Displacement Generation ("LDG") Rate Classification for Run 1

Distributors with currently-approved "standby" rates, including interim standby rates, will be required to address load displacement generation in Run 1 of the filing.[2] The intent of the filings is to develop a common methodology to accurately allocate costs to this group of customers; how to fairly recover the allocated costs (e.g. standby rates or other options) will be discussed in separate future rate design consultations.

In general, two approaches will be adopted in the filings towards allocating costs to load displacement generation customers:

i) treatment as part of a main rate classification, with directions to gather information to determine a LDG charge or credit unit costs; or

ii) treatment as a stand-alone LDG rate classification, with separate load data requirements and separate allocation of demand and customer-related costs.

For Run 1, the distributor should follow the LDG cost allocation approach that is more consistent with the original basis for setting its current standby rates. Distributors must consider the underlying substance of the matter. For greater guidance, if the rates for standby service in the 2006 rate order are equivalent to, or derived from, one of the standard rate classifications, then approach i) should be followed. Otherwise, approach ii) will likely be more appropriate. The Filing Summary should include an explanation if the distributor wishes to use approach ii) for Run 1.

For purposes of approach i), distributors should use the same customer definition that underlies their currently-approved standby rates. For approach ii), a new common definition of the separate LDG classification will be set out, including a threshold (see below).

2.3 Run 2 of the Filings

In Run 2 of the filing model, select rate classification changes must be incorporated. Specifics are listed below.

The Board will consider implementation following the cost allocation review. The results of the Electricity Distribution Rate Design Review will be taken into account.

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[2] This will not apply to any distributor providing standby service but charging standard rates for this service. For Run 2, however, a separate LDG rate must be modeled.

2.3.1 Test Year and Rate Classifications

For 2006 EDR historic test year filers, the applicability of the classification changes will be assessed using 2004 data. For example, if a historic test year filer became a host distributor for an embedded distributor in 2005, it should not add an embedded distributor rate classification in Run 2 of its filing.

2.3.2 Elimination of Legacy Time of Use ("TOU") Rates

The legacy distribution rates known as "Time of Use" must be eliminated in Run 2 of the filing.

This will apply to any legacy TOU rates for GS>50 kW customers. These customers should be placed within one of the following rate classification alternatives for Run 2.[3]

> Alternative 1) If the customers fit within an existing discrete demand range (for example 1000 kW to 5,000 kW), then the classification should be renamed as a GS rate classification referencing the given demand range and remain as a separate rate classification in Run 2. All other GS>50 kW customers that fall within the identified demand range should also be included. Some distributors may have multiple GS discrete demand range classifications. In such cases, the Filing Summary should explain their treatment.
>
> Alternative 2) If alternative 1 does not apply, the distributor should roll these customers into the existing GS>50 kW rate classification for Run 2.

Once the distributor chooses the appropriate alternative, the same cost allocation methodology approved for use with other rate classifications should be applied to the replacement GS rate classification.

The merits of new distribution TOU rates are outside the scope of this project. However, where a distributor currently has such a rate, even on an interim basis, it should be included in its filing. The distributor must explain in its Filing Summary how it has modeled this situation.

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[3] The Technical Advisory Team had also discussed adding a third alternative, namely allowing use of the former Ontario Hydro definition for creating a separate GS "Intermediate" rate classification. But as it has been ascertained that there were varying definitions, and in consideration of the importance of maintaining overall rate structure simplicity, the Board considers the above two alternatives to be satisfactory.

2.3.3 New Large User Rate Classification

In some cases, a distributor may have a customer in a General Service classification that on a 12 month average has demand of 5,000 kWs or more. If this occurred in the test year underlying 2006 rates, then a new Large User rate classification must be modeled in Run 2 of the filing.

The same cost allocation methodology approved for use with other rate classifications should be applied to a new (or current) Large User rate classification.

2.3.4 Common Separate Rate Classification for Embedded Distributors

There are a number of host distributors that are providing a distribution service to embedded distributors. In some cases, host distributors have created a separate rate classification.[4]

In other cases, host distributors that provide service to embedded distributors treat them as General Service customers. However, there are some cost causality factors that suggest the option of establishing a separate embedded distributor rate classification should be explored. These factors include a lower credit risk and an expectation that the direct allocation process will be more applicable to embedded distributors.

The Board wishes to explore a common embedded distributor classification for all host distributors. Therefore a separate embedded distributor rate classification must be modeled in Run 2 of the cost allocation filings by all distributors who served as host distributors in their test year.[5]

Some stakeholders in the present consultations questioned the strength of the cost rationale for creating (or maintaining) a separate embedded distributor rate classification. If a host distributor believes that the resulting unit costs are not sufficiently distinctive, then the merits of creating a new rate classification or including embedded distributor(s) in another suitable classification should be discussed in its Filing Summary.

Some host distributors plan to use the optional Run 3 to model alternative arrangements where the embedded distributor is included in a broader new rate

[4] One host distributor has created a Low Voltage Facilities Charge classification that combines some of the embedded distributors it serves along with select larger customers.
[5] No other customers aside from embedded distributor(s) are to be included in this rate classification for purpose of the Run 2 filing.

classification. This is acceptable provided suitable load data is provided and the costs are allocated using the methodology approved in this Report.

2.3.5 Common Separate Rate Classification for Unmetered Scattered Loads

It is understood that it is more common in other jurisdictions to treat USL as a separate rate classification.

To provide further relevant information to the Board, Run 2 will require all distributors (including those whose 2006 EDR orders expressly identify USL customers as part of the GS<50 kW classification) to model USL as a fully separate rate classification. The separate USL rate classification in Run 2 will include both photo-sensitive and non-photo sensitive loads to promote simplicity in rate classification. Supporting load data is required and the details are set out in Chapter 3.

2.3.6 Rate Classification for Customers with Substantial Load Displacement Generation

In Run 2 of the filings, all distributors serving customers with significant load displacement generation will be required to model LDG rates as a fully separate rate classification. This requirement will apply both to distributors with currently-approved "standby" distribution rates, and to distributors with known load displacement customers (as of 2004, for historic test year filers) but without a separate standby rate classification at the present.

Stakeholders have raised questions about the appropriate materiality considerations for modeling this new rate classification. A threshold will be adopted for the purpose of Run 2 as follows: customers with a standby distribution service requirement of 500 kW or greater requiring standby distribution service must be included in the new Load Displacement Generation rate classification to be modeled in Run 2. The definition of load for such standby distribution service is provided in Chapter 11.

Run 2 will incorporate a single separate rate classification for customers with load displacement generation above the threshold. This is intended to strengthen the reliability of the load data underlying the separate rate classification.

If a distributor has concerns about the reliability of the load data gathered for modeling the separate LDG rate classification, then these concerns should be identified in its Filing Summary. If no reasonable load data is available, the distributor must explain why, and should then use the Run 1 approach (which does not require separate load data for these customers) again for Run 2.

2.4 Optional Rate Classification Changes in Run 3

A distributor will only be permitted to model the following items in an optional Run 3 filing:[6]

- the deletion of a rate classification with supporting rationale
- the addition of a new rate classification beyond those modeled in Run 2, with supporting rationale and cost and load data
- adjustments to reflect the loss of a significant customer/customers, with supporting rationale and cost and load data
- use of the demand allocator 12 NCP, where supporting justification is provided based on the cost characteristics of the distributor's system
- use of default minimum system results from another density stratum, where the distributor can provide strong reasons to justify classification into another density stratum
- use of a distributor-specific minimum system study and PLCC calculation, with supporting explanation of details
- use of the alternative load data option when modeling a separate load displacement generation rate classification
- inclusion of additional costs and benefits relating to the LDG rate classification that were not included in the 2006 EDR filings.

Where a Run 3 of the model is filed, the Filing Summary must include additional supporting explanation and documentation.

A distributor who does not currently have a density and/or a seasonal based rate classification will not be allowed to add such rate classifications in Run 3, as the merits of such additions are not within scope of the present consultations**.**
The project's scope also excludes consideration of polyphase rates. These are not common but may have underlying cost causality support, and any distributor(s) with such an established rate will not be allowed to drop it in Run 3 of the model.

Run 3 must be used where a distributor has been directed to model a specific item (e.g. Merchant Generation rates) by the Board.

If a distributor is interested in incorporating "zonal" rates (i.e. rates based on geographical location) in its optional Run 3, separate load and cost data must be produced.

[6] The items and terms listed below are further discussed in the remaining chapters of the Report.

Chapter 3

3. Load Data Requirements

The Chapter sets out the Directions on load data requirements for the cost allocation filings.

3.1 Load Data - General Requirements

All distributors are generally expected to provide reasonable supporting load data for each separate rate classification to be modeled in Run 1, 2 or 3 of the cost allocation filing.

Distributors considering the addition of a new rate classification(s) in the optional Run 3 of the model should consider and confirm beforehand that suitable load data will be available.

The attached Appendix 3.1 summarizes the specific load data required for each rate classification to be modeled. When reviewing the summary, it should be noted that:

- Appropriate load data will be required in Run 1 and Run 2 even where a distributor drops the rate classification in Run 3.
- Pursuant to the Board's 2003 Load Data Collection Directions, separate load data is not required to be collected for the GS<50 kW classification. For the cost allocation filings, the residual load shape arising from the total distributor load, after the loads of the other rate classifications have been removed, will be used for the GS<50 kW rate classification.
- For classifications where interval meter data is available, for example Large User, Intermediate Use, and Embedded Distributors, such interval meter data should be used.
- For Street Lighting and Sentinel Lighting, the distributor's Board-approved load profile must be used, along with the distributor's data as to installed load.
- Separate load data will not be required in Run 1 for those distributors whose Unmetered Scattered Load or Load Displacement Generation rates will be modeled as part of a main rate classification (in such cases, the load profile of the main rate classification should be used when allocating demand-related charges). The load data requirements for when these customers are modeled as separate rate classifications are set out below.

- The Filing Summary should specifically identify and discuss if the distributor has any customers, aside from Run 1 Unmetered Scattered Load and Load Displacement Customers, for whom separate load data will not be provided.

- The Board has not prescribed load data requirements for Merchant Generation (or Hybrid Facilities). Any distributor who opts to model this as a fully separate rate classification (as opposed to part of a main rate classification) must consider suitable load data and provide an explanation in its Filing Summary. Additional explanation will be required if a load data methodology is used that differs from that used for the separate load displacement generation rate classification in Run 2 or Run 3.

3.1.1 Filing Question

If there is a significant change in the relative load profiles for a historic test year filer (e.g. introduction of battery mats for USL loads, addition or loss of a major large user), a distributor should identify this in its Filing Summary.

3.2 Load Data Requirements for Merging Distributors

For Run 1, distributors will generally be required to model all their currently-approved rate classifications and provide supporting load data.

Separate rules will apply to distributors that have merged and there is a significant prospect that separate rate classifications will not be maintained. If applicable, the effect can be to reduce the number of rate classifications that must be modeled and correspondingly reduce the required load data.

The rules are as follows: If a distributor has Board approval for harmonizing rates prior to, or as part of its 2006 EDR application, or if it has a specific commitment for harmonization in its 2006 EDR application or as part of its MAADs approval by the time of its cost allocation filing, then separate load profiles are not required for each of the merging distributors.

In the above cases, separate zonal rates will not need to be included in Run 1 or Run 2 of the filing.

3.3 Information Required for Completion of Utility-specific Load Profiles

A large group of distributors earlier gathered province-wide load data for the residential and GS>50 kW rate classifications. This load data has been analysed by the Hydro One Load Data Team to develop generic load shapes for these rate classifications.

For the Residential rate classification, utility-specific load profiles will generally be constructed using the above generic load shapes, along with updated local appliance saturation information, distributor consumption data and other distributor information. A distributor must state in its Filing Summary whether:

- It undertook an updated residential appliance saturation survey, either on its own or jointly (in the latter case, list the other utilities).
- It borrowed residential appliance saturation survey results from a neighbouring distributor; and, if so, identify the other distributor and confirm that a test was undertaken to prove that the distributors were a good match for sharing such results.
- It estimated residential appliance saturation; and, if so, the basis of such an estimation (e.g. provision of local kWh data to its service provider).

For the GS>50kW rate classification, load profiles will be constructed using the above generic load shapes, along with industrial grouping data supplied by the distributor, distributor consumption data and other distributor information.

Almost all distributors have advised that they will be using the Hydro One Load Data Team to prepare their utility-specific load profiles. Distributors are requested to contact LoadResearch@HydroOne.com to obtain the most current version of the additional utility-specific information the Hydro One Load Data Team requires.

3.3.1 Filing Questions

Any distributor who is not using the Hydro One Load Data Team to prepare its utility-specific load profile must provide the following in its Filing Summary:

1) The name of its service provider and its relevant qualifications.
2) The source of the load data used.
3) If such a distributor made use of the generic Residential and GS>50 kW load data information, then a summary must be provided of the methodology used to reliably create the utility-specific load profile.

3.4 Weather Normalization

3.4.1 Background – Weather Normalization of Load Data

In order to make the important load data input more reliable for cost allocation purposes, the Board instructed in its letter of March 7, 2006 that distributors must weather normalize their utility-specific load profiles. The Board adopted as the common methodology the established Hydro One weather normalization methodology.

3.4.2 Directions – Weather Normalization of Load Data

The Board directs that the Hydro One methodology be used for weather normalizing the load data used in the cost allocation filings.

A summary of the load data weather normalization methodology that must be followed by all filers was provided at the June 15th Phase Three Technical Workshop.[7]

3.4.3 Filing Question

Any distributor who is not using the Hydro One Load Data Team must confirm that the Hydro One methodology was used to weather normalize its load profile.

3.5 Weather Normalization and Revenue Requirement

3.5.1 Background

As indicated, the Board has directed that the load profiles to be employed for the cost allocation demand allocators must be weather normalized using the established Hydro One methodology. That methodology uses average weather experienced over the past thirty-one years.

For historic test year filers in the 2006 EDR process, the kWhs and kWs used to determine the rate class revenue requirement were based on a three year average usage per customer applied to the 2004 year end customer numbers. This data was thus normalized on a three-year basis. When this three year period was discussed during the 2006 EDR consultations, parties generally believed that 2002 weather tended to be warmer than a typical year, 2003 weather tended to be the same as a typical year, and 2004 weather was colder than a typical year. This may not be accurate for all distributors (whether the distributor is summer or winter peaking may make a difference).

It is not possible to conclude at this time whether a material difference will arise between use of a three year or thirty one year weather normalization methodology. Some parties suspected that any difference would likely not prove material and noted that other estimates were used in the filings.

Another stakeholder did have concern over the potential materiality of the issue. The Board agrees with the suggestion that an output should be added to the filing model to gather further information.

[7] The document is posted on the project Phase 3 web page. See http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_costallocation_phase3.htm

3.5.2 Directions – Additional Model Output

For purpose of sensitivity analysis, the filing model should include an output to show the difference in revenue based on using the approved kWhs from the 2006 EDR model and the normalized kWhs provided by the filer's load data service provider.

If a material difference in revenue emerges between the two methodologies, the matter will be considered as part of the overall interpretation of the results.

The kWh provided by the load data service provider is at the wholesale power level and includes an estimate of losses. It should however be reduced to billing data by removing these losses in order to be consistent with the 2006 EDR model kWh.

Distributors that were future test year filers for 2006 rates should explain in their cost allocation filings how the methodology used to create their respective revenue requirement compares to the methodology used to weather normalize their respective load data for use in the cost allocation studies.

3.6 Load Profile for Separate Load Displacement Generation Rate Classification

Two different load data approaches may be modeled for these customers in Run 2 and Run 3, as the Board considers it useful to obtain a broad range of information on this issue in the filings. All interested stakeholders will be given a future opportunity to comment to the Board on the relative merits of the Run 1, Run 2 and Run 3 approaches towards allocating costs to load displacement generation customers.

3.6.1 Load Profile for Run 2

When a separate LDG rate classification is modeled in Run 2 for customers with standby service requirements greater than 500 kW, the required load data for the classification must be based on the actual metered usage of such load displacement customer(s).[8]

Only one separate LDG rate classification will be modeled in Run 2. This must be undertaken by distributors with currently-approved standby rates, and by all distributors with load displacement customers (with standby service requirements above 500 kW) but no current standby rates.

[8] If a separate LDG rate classification will be modeled in Run 1, then the same approach for load data as for Run 2 should be followed. In this case all customers to whom standby distribution rates were charged should be included.

Distributors are expected to apply a reasonable effort to identify their load displacement customers with standby service requirements above 500 kW. The distributor’s Filing Summary must identify any concerns or qualifications about the reliability of the load data collected. If the distributor believes it has not gathered minimally-acceptable load data, then it must explain in its Filing Summary what efforts were made and propose another treatment for its load displacement customers in Run 2 of its filing (for example, treating such customers as part of the appropriate main rate classification(s) and applying the Run 1 cost allocation methodology again).

3.6.2 Load Profile for Run 3

Distributors may file a Run 3 of the filing in which the load data for the separate LDG rate classification is modeled by an alternative method of adding the actual, or estimated if actual not available, metered generator load displacement to the metered usage. An equivalent additional amount must also be added to the total load of the distributor.

The basis and calculation of the above estimation must be explained in the distributor’s Filing Summary. If applying this load data approach, it must be consistently applied to all LDG customers in the classification and not just those for whom actual data is available. Therefore substantiated estimates will be required for the remainder.

Some stakeholders have commented that it is unlikely that all load displacement customers within a distributor will be requiring LDG power at the same time and that there will be diversity on the requirement for LDG load within the separate load displacement generation rate classification.

As part of the consultation process, in August 2006 stakeholders were asked to comment on a filing question that would require distributors to explicitly address the generation diversity where a distributor models a separate Load Displacement Generation rate classification in Run 3. Some stakeholders indicated the question was reasonable. One suggested it should go further to mandate that a distributor must take into account diversity among the load displacement facilities. However, another stakeholder stated that the data to determine diversity among the load displacement generators may not be available to distributors.

The Board intends through the filing questions below to require all affected distributors to address the generation diversity issue, and to provide an explanation if they believe diversity does not exist or if suitable data cannot be obtained to assess the issue.

3.6.3 Filing Questions

1) Indicate the number of customers in the distributor's service territory that have load displacement generation equipment above 500 kW.

2) To the extent the distributor has the information available, categorize the above load displacement facilities by size and type of generation (wind, gas-fired, cogeneration, etc.) and the associated LDG requirement.

3) As the load data is based on only one year's experience, indicate whether the load data developed for the load displacement generator customers is considered to be representative of the ongoing performance of the associated generation facilities.

4) In Run 3, if a separate load displacement generation rate classification has been modeled using actual or estimated metered generator load displacement, the distributor should explain in its Filing Summary a) what steps were taken to gather relevant data to assess the existence of diversity, and b) what steps were taken to reflect any diversity of generation in its filing. The Filing Summary must provide an explanation if the distributor believes diversity does not exist or if suitable data cannot reasonably be obtained to assess the question.

3.7 Load Profile for Separate Unmetered Scattered Load Class

Where USL[9] is to be treated as a separate rate classification in the model (e.g. Run 2), the combined load profile must be calculated as follows:

Step 1) Non-Photo-sensitive Loads

Non-photo-sensitive loads must use a deemed load profile, constructed from the combined load shapes of the various types of non-photo-sensitive loads that make up the classification.

The total kWh consumption of each type of unmetered scattered load for purpose of development of the utility-specific load shape and demand allocators will be the kWh consumption estimate used by the distributor for billing purposes in the test year (and weather-normalized where applicable). For most types of non-photo-sensitive unmetered loads, a flat load profile will be used.

[9] Photo-sensitive and non-photo-sensitive users are to be treated as part of the same single USL rate classification.

Step 2) CATV Battery Mats

For CATV power supplies (excluding any battery mat component), a flat load shape must be used for the present filings.

A separate load shape must be applied to the weather-normalized consumption of CATV power supply battery mats where they are in service in the distributor's test year.

Distributors that filed their 2006 rate applications on a forward test year basis and whose test year load includes CATV power supply battery mats, must obtain information on the number and installed capacity of battery mats (e.g. from the local cable company). If there is a concern about the information available, this should be noted in the Filing Summary.

If CATV power supply battery mats were not taken into account in a future test year filer's 2006 EDR application, then the approved revenue requirement figures may need to be corrected for present filing purposes. Stakeholder written comments provided differing views on the matter. A flexible approach will be adopted in the filings as follows: the Filing Summary of each of the affected distributors should discuss the issue and explain why or why not an adjustment is reasonable in its specific circumstances. If an adjustment is implemented, a justification of the amount should be provided.

As no battery mats were in place in Ontario prior to 2005, the bulk of the distributors that based their 2006 rate applications on historic year data (2004) will not need to make an adjustment for battery mats.

Step 3) Photo-sensitive Loads

The total kWh consumption of each type of unmetered scattered load for purpose of development of the utility-specific load shape and demand allocators will be the kWh consumption estimate used by the distributor for billing purposes in the test year (and weather-normalized where applicable). For most types of non-photo-sensitive unmetered loads, a flat load profile will be used.

For photo-sensitive loads, the distributor's Board-approved load profile for street lighting must be used.

Step 4) Combining Results

The resulting load shapes under steps 1), 2) and 3) will be combined to create a single separate USL load profile.

Chapter 4

4. Test Year and Revenue

Directions on the test year and revenue to be used in the cost allocation filings are presented in this Chapter.

4.1 Test Year

4.1.1 Background

Cost allocation studies are generally performed using data for a one year reference period or “test year”.

For the purpose of the upcoming filings, the revenue requirement (as defined below) and the data underlying the approved 2006 distribution rates will be the basis of the cost allocation studies. Therefore, any adjustment that was approved to a distributor’s 2006 EDR revenue requirement by the Board must also be appropriately reflected in the cost allocation filing.

4.1.1.1 Filing Question

For future reference, a distributor is asked to identify in its Filing Summary any major changes to its distribution system that may have occurred since its 2006 EDR test year and which could materially impact its cost allocation results (for example, addition of a new customer with a demand greater than 5,000 kW where the distributor does not currently have a Large User classification).

4.1.2 Direction – Distributors that used a historical test year in the EDR 2006 application

For distributors that used a historical test year in their 2006 EDR applications, the underlying 2004 trial balances will be the basis of the cost data to be filed for the cost allocation review, subject to the following adjustments:

i) the Board-approved tier 1 and tier 2 adjustments;
ii) cost of capital and PILS as included in approved 2006 EDR rates; and
iii) any additional adjustments ordered by the Board in its final 2006 rate decisions.

The adjustment to distribution rates for smart meters ordered in the Board’s Decision RP-2005-0020/EB-2005-0529 should be excluded, as the cost of smart meters has not been included in the revenue requirement. No other adjustments will be allowed.

The account data underlying the trial balances for the 2006 rates should not include costs and revenues related to non-utility operations and to non-recurring regulatory accounts tracking deferrals and variances.

In some cases, a distributor will need to move dollars within the approved revenue requirement envelope from one account to another to reflect a better cost allocation methodology. The filing model is designed to handle these accounting adjustments. By way of illustration, if meter reading costs were included in Account 5630 - Outside Services Employed, then these costs should be removed from this account and added to Account 5310 - Meter Reading Expense to ensure meter reading costs are allocated using the proper allocator (note Account 5630 will be allocated using the O&M allocator, while meter reading expenses will be allocated based on a weighted meter reading cost allocator).

4.1.3 Direction - Distributors that used a forward test year in the 2006 EDR applications

For distributors that had earlier filed using a forward test year (i.e. Hydro One Networks Inc., Hydro Ottawa Limited, and Toronto Hydro-Electric System Limited), the trial balance underlying the Board-approved 2006 rates should be used for the cost allocation filings. No additional adjustments should be made.

It is understood that the trial balance for some of these 2006 EDR applications did not include details of all the accounts included in the trial balance, but that the application was based on a grouping of accounts. For the purpose of the cost allocation filings, a distributor that used a forward test year in its approved 2006 rate order and did not provide a detailed trial balance in its 2006 rate application, will need to regroup the trial balance in accordance with the grouping process described in this Report.

Similar to the historic test year filers, the costs and revenues associated with non-utility operations and with non-recurring regulatory accounts that track deferrals and variances should be excluded. In addition, the adjustment to distribution rates for smart meters ordered in the Board's Decision RP-2005-0020/EB-2005-0529 will be excluded, as the cost of smart meters has not been included in the revenue requirement. Similar to historic test year filers, a distributor may be required to move dollars between accounts to reflect a better cost allocation. No other adjustments will be allowed.

4.1.3.1 Filing Question

Any distributor that was a future test year filer for 2006 rates must indicate in its Filing Summary whether the trial balance being used for its cost allocation filing was submitted previously as part of its EDR 2006 filings or was developed afterwards.

4.1.4 Direction – Distributor(s) that will not have approved 2006 rates at the time of its cost allocation filing

In the case of any distributor that does not have approved 2006 rates at the time of its cost allocation filing, the distributor will still have filed a 2004 trial balance as part of its regulatory reporting requirements. The filed 2004 trial balance must be used by such a distributor as the main source of financial information for the cost allocation filing. This will be consistent with the data underlying the cost allocation filings of most other distributors.

Consistent with the approach used in the 2006 EDR process, the net fixed asset components in the 2004 trial balance that support the calculation of the rate base will be adjusted to reflect the average of the 2003 and 2004 values. If further direction is required on the averaging of net fixed assets, a distributor should refer to the 2006 Electricity Distribution Rate Handbook.

The 2004 trial balances will also be adjusted for the third tranche of Market Based Rate of Return (“MBRR”) and estimated Payments in Lieu of taxes (“PILs”) assumed in the 2005 rates. The costs and revenues associated with non-utility operations and non-recurring regulatory accounts should be removed.

Revenue will be determined by applying the distributor’s current approved rates, excluding regulatory assets, to the billing determinants consistent with those used by a distributor that filed for 2006 rates. The billing determinant for the number of customers by rate classification will be the 2004 year end number of customers. The volumetric billing determinant will be the three-year average (2002-2004) of rate classification usage per customer (i.e. kWh per customer or kW per customer as applicable) applied to the number of customers by rate classification at year end 2004.

4.1.5 Note on calculation of Rate Base and Accumulated Depreciation

The EDR 2006 filings rate base was defined as the average net book value for the test year. For the purpose of the cost allocation filings, rate base and accumulated depreciation will be established in similar fashion as the average net book value for the test year. These numbers should be available from the EDR 2006 model.

4.1.6 Direction - Adjustments to the Trial Balance

Except where may be specifically required in this Report, pro forma adjustments to the revenue requirement and cost structure supporting the approved 2006 rates are not to be made in the cost allocation filings.

If a distributor feels there has been a change in the operation of its utility that would significantly impact the approved revenue requirement and rates (for example, a new large use customer connects to the distribution system), then the distributor should disclose and discuss this information in its Filing Summary.

4.1.7 Filing Questions

It may be of future assistance to the Board to better understand how a distributor attributes various costs to certain key accounts. The following questions must be answered in the filings:

1. As a distributor, summarize your capitalization policies (such as treatment of overhead allocation and types of expenses capitalized instead of being charged to O&M). The distributor may wish to refer to its 2006 EDR application.

2. Outside Services Employed (Account 5630) may have costs relating to multiple functions. Disclose the functions that are charged to this account (e.g. meter reading, call centre, etc.).

3. Disclose in which account(s) Customer Information System Expenses are currently recorded and the activities it includes.

4.2 Revenues

4.2.1 Background

A key output of the cost allocation filing will be a comparison of revenues and costs by rate classification. To the extent possible, revenues and costs should be determined on the same basis. It is therefore important that the meaning of “revenue” be accurately defined.

4.2.2 Direction - Definition of Revenue for Cost Allocation Filings

The service revenue requirement on sheet 5-1 of the distributor’s approved 2006 EDR model will be the basis of ensuring all the proper costs have been included in the cost allocation filing. It is important that all distributors obtain their approved 2006 EDR model (available upon request from Board Staff).

The revenue per rate classification inherent in a distributor's approved 2006 revenue requirement must be used in the revenue to cost ratio calculation. This means that the revenue per rate classification for cost allocation purposes will be defined as the sum of:

i) The base revenue requirement allocated by rate classification shown in sheet 7-1 of the approved 2006 EDR.
ii) The revenue off-sets allocated to the rate classification as defined in Appendix 4.1.
iii) The allocation by rate classification of CDM from sheet 7-3.

The regulatory asset adders and the adjustment for smart meters will not be included as revenue in the cost allocation filings.

Appendix 4.1 outlines each account included in the revenue off-sets and the allocation method to be used to allocate these accounts to each rate classification. In general, Accounts 4082, 4084, 4090, 4225 and 4235 form a large proportion of the total revenue off-sets.

Chapter 5

5. Direct Allocation

Directions on the direct allocation method to be used in the cost allocation filings are presented in this Chapter.

5.1 Background

As an initial step in a cost allocation study, a distributor should identify any significant distribution facilities that are dedicated exclusively to only one customer rate classification. The costs of such a facility, and the associated O&M expenses, should then be directly allocated to the customer classification that it is exclusively dedicated to. To prepare and review proposed direct allocations will take time and effort and therefore it is not encouraged for items that a distributor considers insignificant.

Direct allocations may not prove that common in practice, as more than one customer classification may make use of the facilities in question.

A stakeholder has asked for clarification of how to apply direct allocation where the customer in question has access to other parts of the system for additional reliability. For instance, there may be a situation where a facility (most likely a conductor) is directly assignable to a large customer as the feeder provides service to only the large customer under normal circumstances; however, under emergency circumstances there is access to back-up service provided through other facilities on the distributor's integrated system. Under this situation, it is appropriate to charge this large customer for a share of the facilities providing this redundancy or back-up, along with the full cost of the directly assignable facilities. If this situation arises, the distributor should provide a full explanation and documentation of how the directly assignable facilities, as well as the appropriate assignment of back-up facilities, are allocated to the large customer. The large customer's NCP should be used as the default allocator in these situations, but an alternative allocator may be used if supported by an adequate justification and supporting documentation (including a summary of the difference arising from use of the alternative allocator).

The consultations for this project indicated direct allocation should be explored in the following circumstances:

- A Transformer Station owned by a distributor that is 100% dedicated to customer(s) in the same rate classification.
- A feeder that is 100% dedicated to customer(s) in the same classification.
- Costs directly associated with load displacement generation assets.

Some stakeholders suggested that direct allocation be permitted in circumstances where less than exclusive (i.e. "predominant") use of certain facilities or services are made by a single rate classification. This argument has been rejected because using more than one facility to serve a customer's distribution requirements necessarily means other distribution facilities are used to provide a portion of the service to the customer. The vagaries associated with equitably quantifying the cost causality responsibility of these other non-directly assignable facilities leads the Board to favour the more well-established 100% (i.e. exclusive use) test for direct allocation. The 100% use test can also be applied more clearly and consistently.

It was suggested that where there are any assets that are "predominantly", i.e. at least 90%, but not exclusively dedicated to one customer classification, distributors should disclose this in their filings so ratepayers can further question their allocation in future rate cases. However, as the Board believes that the 100% use test better reflects cost causality and standard cost allocation practice, the additional information sought will not ultimately prove helpful and therefore this item will not be included in the filing questions.

Where the prescribed test for direct allocation cannot be met, a distributor will still be required to consider whether distribution assets should be broken out into bulk, primary and secondary (discussed below) to more accurately allocate costs of facilities to rate classifications based on how they use various parts of the distribution system.

5.2 Direction – Direct Allocation Methodology

Direct allocation must be applied if, and only if, 100% of the use of a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification.

If a distributor proposes to use direct allocation, it must support its filing with the following:

i) A summary of supporting accounting records for the specific facility in question.

ii) A single line diagram/schematic indicating the facility concerned, the customers served, and any other facilities serving the same customers.

iii) If direct assignment is applied to a customer that also receives back-up service, the filing must include an explanation and supporting documentation on how an appropriate share of back-up serve was determined and allocated. Additional justification and supporting analysis is also required if an allocator other than the customer's NCP is used.

If costs or assets are directly allocated, the direct allocation should capture all the associated accounts; for example, in the case of assets, the gross value, accumulated depreciation and depreciation expense, and any contributed capital.

Direct allocation must also be used where identifiable O&M activities can be directly allocated to one customer classification, and where supporting documentation in terms of sub-account records and explanations as to the related activities can be provided.

When direct allocation is used, the distributor should consider whether it needs to adjust the appropriate allocation factors so that the rate classification to which costs for a specific function are directly allocated is not allocated further costs related to that function, except where there are joint costs that apply to the customer classification. For example, if a customer classification has all its assets and O&M costs directly allocated to the classification, then the load data used to allocate "common" assets and O&M costs should exclude the load data associated with this customer classification. There may be other instances in which no adjustment is needed. The Filing Summary should address whether or not an adjustment was considered appropriate by the distributor and confirm it was undertaken where warranted.

The filing model will allow a distributor to define which costs in the trial balance that supports the 2006 approved rates should be directly allocated to a specific rate classification.

Chapter 6

6. Functionalization

Directions on the process to functionalize costs in the cost allocation filings are presented in this Chapter.

6.1 Grouping

6.1.1 Background

The process of functionalization of costs is an important step in the cost allocation process, as it sets up the framework for the categorization and allocation steps. The functionalization step is the process that groups relatively homogeneous costs together into functions.

In some cases, further breakdown of the major accounts is required to properly reflect specific functions. Each function, therefore, will have corresponding accounts or sub-accounts. The Uniform System of Accounts ("USoA" or "accounts") for Ontario distributors will facilitate a common approach towards functionalization in the cost allocation filings.

For cost allocation purposes, the ultimate grouping of accounts will be done at the level of refinement necessary to implement the various proposed allocators. A greater level of disaggregation is not considered reasonable to achieve the goals of the filings.

Once functionalized, the costs will be categorized as demand-related and/or customer-related using the specific categorization factors discussed in Chapter 7.

6.1.2 Direction - Grouping of Accounts and Sub-accounts in Cost Allocation Filings

In the cost allocation filings, each adjusted 2004 account shown in column P of Sheet 2-4 of the approved 2006 EDR application will be placed into a group that shares a common allocation process. In addition, for those accounts that will be further broken down into sub-accounts in the cost allocation model, the sub-accounts will also be grouped.

The final grouping in the cost allocation filings are based on the approved common cost allocation methodology. The comprehensive mapping of each account or sub-account to a group is shown in Appendix 6.1.

6.2 Breakout of Accounts into Sub-accounts: Definitional Issues

6.2.1 Introduction

The objective of breaking out accounts into sub-accounts is to better reflect the costs ultimately associated with specific assets according to the role of these assets in the distribution system, i.e., their function. This in turn will affect the share of costs allocated to the various rate classifications.

For example, Account 1835 - Overhead Conductors and Devices contains the assets associated with providing the overhead conductor function. To more accurately undertake cost allocation, this account could be further divided into sub-accounts. Once each applicable account has been subdivided into sub-accounts that reflect specific functions, the costs can more readily be allocated to rate classifications based on whether the given customer classification does or does not use the particular function.

For the purposes of the cost allocation filings, certain major accounts will be broken down into sub-accounts (see Chapter 7 for a list of the major accounts and sub-accounts) to reflect the following functions:

- Bulk (if any)
- Primary
- Secondary
- >50kV assets deemed to be distribution.

Every distributor will have primary and secondary sub-accounts. But not all distributors will have bulk asset sub-accounts. A distributor should carefully exercise its judgement when applying the bulk asset test set out below to its system. Further comments are provided on the intent of the bulk asset test to assist distributors when they apply it.

An input sheet has been provided in the model to accept the sub-account information by function.

6.2.2 Bulk, Primary and Secondary Functions

6.2.2.1 Background

Functional Approach

The bulk, primary and secondary sub-accounts relate to assets associated with performing bulk, primary and/or secondary functions within a distribution system.

The key objective of the cost allocation is to allocate costs among classifications appropriately reflecting cost causality. This objective is furthered by separating distribution assets into bulk, primary and secondary functions. At the same time the approach should be relatively simple and straightforward, so that the exercise of breaking down the accounts and the interpretation of the results can be consistent and reliable.

Discussions with stakeholders revealed that a simple voltage-based test would not be workable for all distributors. Various other approaches to defining bulk were discussed over the length of the consultations. In the end, the Board believes that a "functional" approach is most appropriate to the issue of identifying bulk assets.

A distributor should consider its individual circumstances and the tests below to determine and explain in its filing whether each of the following individual assets includes costs on a combined basis associated with the bulk, primary, and secondary functions.

1830	Poles, Towers and Fixtures
1835	Overhead Conductors and Devices
1840	Underground Conduit
1845	Underground Conductors and Devices

If there are amounts included in these accounts that perform bulk, primary, and/or secondary functions, then they need to be split into sub-accounts to reflect those different functions. Directions on how to implement this are provided below.

Stakeholder Discussions on Bulk Asset Test

The Board believes the most appropriate manner to implement a functional approach towards identifying bulk assets involves a separation of the distribution assets to identify any assets that were built with consideration of the distributor's system peak. This approach is also consistent with the intended allocation of bulk costs using Coincident Peak as the demand allocator (see Chapter 8).

The Board acknowledges the extended stakeholder debate on this issue during which various other options were carefully reviewed. The Board believes a careful approach towards a common definition of bulk is prudent at this stage to gather reliable information in the cost allocation filings. While there was some stakeholder discussion on the size of load served by the facilities, this will not be part of the bulk test since it could lead to allocation based on the type of customer (rather than the function served by the assets). Some stakeholders also suggested that all facilities are used to deliver load which contributes to the system peak. This view is not accepted by the Board because it fails to take into account the fact that while these facilities may contribute to serving the system peak they were designed and built to meet the non-coincident peak of a specific part of the distributor's service area.

During the consultations, an approach of allowing distributor's to make and defend their own judgement as to whether bulk assets existed was discussed. However, some stakeholders were concerned that this might lead to inconsistent application of the bulk asset test. Given the risk that significant costs could be shifted between rate classifications if differing, or an overly broad, definition(s) were implemented, the Board prefers a more prescriptive approach in its general directions.

Given the varying stakeholder views on this much discussed issue, the Board considers the most useful steps are i) to provide a clear and workable definition of "bulk" assets for the cost allocation filings, and ii) to provide some guidance on what may be useful to keep in mind when distributors apply the definition. These are set out below.

Various stakeholders wondered if there may be a need to revisit the definition of bulk assets following the filings. The Board would point out, however, that it has deliberately adopted a focused definition of bulk to promote reliable and consistent application. Moreover, considerable time has been devoted to reviewing alternative proposed definitions of bulk during the present year-long consultations. The importance of allowing adequate time in 2007 to prepare and start reviewing the 2008 rate applications is also an important practical consideration.

6.2.2.2 Direction – Definition of Bulk

A functional approach must be adopted towards identifying the assets that may serve a bulk delivery function in some distribution systems.

The test to determine if any bulk assets exist in a given distributor's system is to identify all facilities that were built to support the system peak of its distribution system. Note the test is to be applied in light of the function when the asset was built, not its present function, because use of the former will reflect the reason for the facility's initial sizing and provide a more stable cost allocation methodology.

When applying the test, distributors should distinguish between assets that were built to support the distribution system's peak or the customer's peak. Only assets built to support the distribution system's peak will be treated as bulk assets for the cost allocation filings.[10]

If and only if a distributor determines that it has bulk assets, then the assets used to deliver power to a distribution station are also part of the bulk assets.

[10] Assets built to support the customer's peak are primary or secondary assets; and the voltage-based test provided should be applied to identify secondary assets.

6.2.2.3 Implementation Guidance on Application of Bulk Definition

For cost allocation purposes, as indicated the test to be applied by distributors in defining bulk assets is to identify those assets that were built to support the distribution system's peak. When working with the bulk test, it would be helpful to recall the overall steps in the cost allocation: bulk assets will be allocated using Coincident Peak, while primary and secondary assets will be allocated using Non-Coincident Peak (see Chapter 8).

Note the above definition of bulk assets is not intended to capture all facilities that end up supplying any loads that contribute to the current system peak, as this approach would miss the reason for the initial sizing of the facility and would also lead to an overly broad application of bulk. Instead, the bulk definition should only include assets which were specifically designed and built with the intent to serve the system peak.

By way of further general guidance, if a distributor has assets that are directly involved in the delivery of power to larger users (e.g. Large Users, GS Intermediate, or Embedded Distributors), then the distributor should carefully consider whether such assets were built to serve the distribution system peak and therefore perform a bulk function. Each distributor must exercise its own judgement as there are known exceptions to any generalizations. Distributors are reminded the test to be applied is the function the asset serves, and not the nature of the user *per se*.

Factors that suggest bulk assets do not exist include:

- the assets have a delivery voltage of <13kV
- circuits that are below three phase.

Distributors should consider their specific system when applying the bulk asset definition to distribution stations. For instance, if there is only one distribution station serving a distributor's system, then chances are it was sized around the distributor's Co-incident Peak ("CP") as all of the distributor's power at the time of the con-incident peak must go through this one station. As a result, such a distribution station assets would likely be treated as a bulk asset to be allocated using CP.

In contrast, if there are multiple distribution stations serving a distributor's system, then Non-Coincident Peak is typically the driving force for the size of distribution station as it is sized around meeting a geographic area's peak within the distributor's service territory and not the distributor's total system peak.
In such cases, which stakeholders believed would be more common across the Province, such distribution stations would not be serving a bulk function and should be allocated using Non-Coincident Peak ("NCP)". In effect, the sizing of a distribution station for NCP means that CP is not significant in the sizing of the distribution station and therefore the latter is not an appropriate allocator.

It is possible that within a distribution system, a portion of assets that operate at the same voltage level (normally over 13 kV) could be serving a bulk function and the remainder a primary function. In such cases, the assets should be subdivided depending on the function for which the assets are actually used. This would be a matter for a distributor to decide and justify based on detailed knowledge of its system characteristics.

Some utilities commented that their distribution system is designed and operated in a “fully-integrated” manner and therefore they believe they may not be able to isolate any bulk assets as defined above. Even where a distributor suspects this may be the case, the distributor must first apply the bulk test provided and then carefully consider how it may or may not apply to its distribution system.

Where there is geographical separation of a distributor’s overall system with no interconnection between the separate parts, for cost allocation purposes the distributor will not have bulk assets as defined above.

6.2.2.4 Direction – Definition of Secondary

For this function, a voltage-based definition will be adopted: the secondary sub-accounts will cover all assets owned by the distributor operating at <750V, whether financed through contributed capital or rates.

6.2.2.5 Direction – Definition of Primary

The primary sub-accounts will cover all assets that are not identified as bulk assets (if applicable) or as secondary assets.

6.2.2.6 Filing Questions – Supporting Distribution System Information

1. The Filing Summary should explain how the distributor applied the Board’s bulk asset test to its system, and why it concluded it did or did not have bulk assets.

2. All distributors will be required to include in their filings a single line diagram or schematic of their distribution system.

3. Where a distributor believes it has assets that serve a bulk function under the Board’s test, an explanation must also be added to the diagram or schematic filed indicating which specific assets have been identified as bulk and the customers by rate classification that are served from such bulk assets.

6.2.2.7 Specialized Circumstance

When the Technical Advisory Team commenced its discussions of functionalization, participants noted that subtransmission costs had been segregated in a previous application submitted to the Board by Hydro One Networks Inc. in support of its approved Low Voltage Facilities Charges. Some stakeholders suggested that it would be undesirable if the present filing provided for a less refined pooling of costs. Mindful of the prior decision on Hydro One's Low Voltage Facilities Charges, the Board believes it helpful in this specific circumstance to permit flexibility in the functionalization methodology to be used by the distributor

Therefore Hydro One will be allowed to include a subtransmission cost pool for the purpose of its upcoming cost allocation filing, provided its Filing Summary also provides an explanation (including supporting schematic diagram or equivalent) and justification of this alternative sub-functionalization methodology. In addition, its Filing Summary must discuss the impact(s) on its filing from using a "subtransmission" cost pool compared to the standard "bulk" asset cost pool, as defined above.

The Board expects Hydro One will provide further justification if it wishes to use CP to allocate this subtransmission cost pool. The rationale provided should explicitly take into account the discussion in Chapter 8 as to the circumstances under which the use of CP or NCP is most appropriate.

6.3 Breakout of Accounts into Sub-accounts: Implementation Issues

6.3.1 Direction – Identifying Bulk, Primary and Secondary Costs

Once the bulk, primary and secondary assets have been identified based on the above tests and guidance, it is necessary to break out the associated costs. As the accounting granularity is presently not available to do such a breakout, the distributor must provide an estimate of the percentage of costs of the assets in each of the bulk, primary and secondary buckets. This percentage will be applied to the total cost in the asset account. For contributed capital see below.

The Filing Summary must explain how the distributor broke out its costs between bulk, primary and secondary assets. The following approach is to be used:

> The distributor should determine the unit cost of installing bulk, primary and secondary assets and then apply the kilometres of line for the bulk, primary and secondary assets to these unit costs. The result from each type of asset should be divided by the total for all assets and this percentage should be used to determine costs by asset type.

6.3.2 Direction - Breakout of Bulk, Primary and Secondary Sub-accounts

The bulk, primary and secondary sub-accounts should be broken out to the corresponding rate classifications that use those assets. In particular:

- Secondary costs will only be allocated to those rate classifications that use secondary assets.
- Primary costs will only be allocated to those rate classifications that use primary assets.
- Bulk costs will be allocated to those rate classifications that use bulk assets. For many distributors, bulk costs will be allocated to all classifications since the bulk assets deliver power to the primary and secondary assets.

If only a proportion of a rate classification uses a group of assets, then the dollars will be allocated based on the percentage of customers for customer-related costs and by the percentage of load for demand-related costs.

6.3.3 Direction - Customer Data for Bulk, Primary and Secondary

For each rate classification, a distributor will need to provide the number of customers that use the bulk (if any), primary and secondary assets. The customer numbers are <u>not</u> the number of customers that take power from the assets but the number of customers that are supplied through the assets directly and indirectly connected. This would include customers who are connected to a distribution system station that is connected to what is identified by the distributor as a bulk system. The examples in Appendix 6.2 have been developed to assist with the understanding of how the customer number is entered into the filing model to implement the separation of bulk, primary and secondary assets. Some distributors may have to submit estimates of customer numbers if they do not have data on the exact numbers of customers per feeder.

6.3.4 Adjusting Load Data re Bulk, Primary and Secondary

6.3.4.1 Background

The load data supplied by the distributor's load data service provider will have to be adjusted by the distributor to reflect its split into bulk (if any), primary and secondary. The break out will not be undertaken by the load data service provider. The break out must be undertaken by the distributor and entered into the model. A methodology is set out below. Further guidance may be provided in the filing instructions.

6.3.4.2 Direction – Adjusting Load Data re Bulk, Primary and Secondary

The load data supplied by the distributor's load data service provider will have to be adjusted by the distributor to reflect its split into bulk (if any), primary and secondary.

The coincident peak for bulk ("BCP") is the coincident peak for those customers for whom power is delivered through any bulk assets (includes customers fed from primary and secondary assets through the bulk assets).

The distribution system coincident peak ("DCP") supplied by the distributor's load data service provider must be multiplied by the percentage of load that uses any bulk assets identified to obtain the BCP. This percentage will be based on an engineering estimate of the load fed through the bulk system. Since the bulk system is defined to be assets which were built to support the distributor's system peak, it is highly unlikely that the BCP will not be 100% of the DCP.
In the case where a distributor does not have an integrated distribution system, then the distributor will not have bulk assets.

The distributor's load data service provider will provide the system NCP for each classification ("DNCP").The primary NCP ("PNCP") for each classification (if applicable) will be calculated by multiplying the DNCP by the percentage of load in the rate classification that uses the primary assets.

In the same manner, the DNCP must be adjusted for those customer classifications that use the secondary assets.

6.4 >50kV Assets Deemed to be Distribution

6.4.1 Background

This sub-account relates to >50 kV assets deemed by the Board to be distribution. Typically, >50 kV asset is a Transformer Station (TS) that a distributor owns and operates. The costs of these >50kV assets that transform power from transmission voltage to the distributor supply voltage are included in the distributor's distribution rates. If Hydro One has required a distributor to make a capital contribution towards the construction of a Hydro One-owned TS, then this capital contribution is also a >50 kV asset included in the distributor's distribution rate base.

6.4.2 Direction – Treatment of >50kV Assets Deemed to be Distribution

In order to establish a consistent approach in understanding the pure distribution costs associated with each rate classification within a distributor, costs associated with the >50 kV assets will be identified and shown separately within the filings.

Generally, a distributor with >50kV assets would include these assets under Account 1815 Transformer Station Equipment. There is no need to split this account between >50kV assets and <50 kV assets as it is all >50kV assets. When a distributor does have >50kV assets, it must consider if the accounts shown below include costs that are associated with these assets as well as assets that are <50kV assets. If this is the case, these accounts will need to be split into sub-accounts to reflect >50kV assets and the <50kV assets.

1805	Land
1806	Land Rights
1808	Buildings and Fixtures
1810	Leasehold Improvements
1825	Storage Battery Equipment

6.5 Line Transformers

6.5.1 Background

A customer that is connected to a distributor's secondary assets will use the distributor's line transformer assets to step-down the voltage to the supply voltage of the secondary assets. Assuming all customers connected to the secondary assets use the distributor's secondary assets, then line transformer assets should be allocated in a method consistent with secondary assets. However, this is not always the case. A distributor may have customers that own their own secondary lines and poles but take service from the distributor's line transformers. In this case, customer-related line transformer assets need to be allocated based on the number of customers using the line transformers and demand-related line transformer assets need to be allocated based on the NCP load that is stepped-down by the line transformers. In this circumstance, the number of customers and the NCP load used to allocate the distributor's line transformer assets is different than the number of customers and NCP load used to allocate the distributor's secondary assets.

6.5.2 Direction – Treatment of Line Transformers

To properly allocate line transformers assets (Account #1850) and the associated maintenance costs (Accounts #5035, #5055, #5160), the cost allocation model will require customer numbers and NCP loads by rate classification that reflect the distinct usage of the line transformer assets which may be different than the secondary assets.

6.6 Capital Contributions

6.6.1 Introduction

Contributed capital is a third-party contribution made towards the cost of constructing the distributor's distribution assets. Formerly, these contributions were included in rate base and were rolled into equity when distributors were required to transfer their assets to corporations.

Currently, capital contributions are accounted for as reductions to the cost of related capital assets and are amortized at rates corresponding to the useful lives of those related capital assets.

Contributed capital is determined by the distributor's Conditions of Service which outlines demarcation points, basic service, and the economic valuation model. The amount of contributed capital can vary greatly between distributors due to differences in load growth and contributed capital policies.

Distributors' accounting records may not support the level of detail required for the cost allocation filings. Furthermore, the treatment of contributed capital may vary between distributors. The objective below is to ensure the proper allocation of contributed capital between the asset classes and, eventually, customer classifications.

6.6.2 Background - Determination of Contributions

The level of contributions are determined by the net present value of the total costs of a project, offset by the revenue stream generated by the project's new customers.

In addition to extensions, upstream costs may have been included as costs of the project. These are growth-related capital costs that the distributor was required to expend in order to provide distribution services, but are not specifically attributable to the project. Examples of such growth related costs are distribution stations, feeders, etc.

6.6.3 Background - Source of Capital Contributions

Residential

These contributions are generally for subdivisions and are determined by the outputs of the economic valuation model.

General Service and Large Uses

These installations are varied and can include transformation and other distribution plant.

Road Widenings/Relocations

Road widenings and improvements, related to capital programs, are undertaken by municipalities and regional authorities and can involve removal and relocation of distribution assets. Transformation costs would not typically be involved. Cost sharing is generally determined by a standard formula according to applicable legislation.

6.6.4 Direction - Breaking out of Contributed Capital in Filings

The following outlines two approaches to assign capital contribution to the various assets. The Filing Summary must identify which approach was used.

Recommended Approach

If the distributor can conduct a detailed analysis of contributed capital by either asset type or rate classification, then it must do so and provide its methodology and supporting information in its Filing Summary. When the capital contribution is assigned to asset type, the supporting analysis must explicitly identify capital contributions associated with bulk (if any), primary and secondary assets.

The filing model will have the capacity to allocate capital contributions to rate classifications using the direct allocation feature, and filing instructions to permit this will be provided.

Alternative Approach

If the distributor is not able to use the preferred approach, then the percentage of the gross capital dollars of the assets on which contributed capital was collected must be used to allocate capital contribution to the assets.

A distributor will assign capital contributions to the various assets outside the filing model and enter the results of the assignment in the appropriate input sheet of the model.

6.6.5 Filing Question

If a distributor uses the alternative approach, it must indicate the proportion of its total assets that contributed capital represents.

6.7 Depreciation and Accumulated Depreciation

6.7.1 Background

For rate setting purposes in the 2006 EDR process, the net fixed assets in the rate base were determined as the average of the opening and closing balances. For cost allocation purposes, the average net fixed assets is broken down by USoA account and cost allocation sub-account. This is determined by subtracting the average accumulated depreciation from the average gross fixed asset by USoA account and cost allocation sub-account.

Note that the average gross fixed assets for various asset types is recorded in the USoA on a separate basis but the average accumulated depreciation may not be. In addition, the annual depreciation associated with the assets is most likely not recorded on a separate basis.

6.7.2 Direction– Break Down of Depreciation and Accumulated Deprecation

A distributor must break down the average test year values for accumulated depreciation as well as the test year depreciation values, by USoA account and cost allocation sub-account.

In most cases, a distributor has recorded accumulated depreciation and depreciation expenses by the various assets and this information will be used to determine the net fixed assets and depreciation assigned to the USoA account and cost allocation sub-account.

If a distributor has better information available in regard to the break out of accumulated depreciation and depreciation expenses, then this information must be used. If a distributor does not have this information available, then accumulated depreciation and depreciation can be assigned to the accounts and sub-accounts based on the break down of the assets. Further guidance may be provided in the Board-issued filing instructions.

The generic minimum system approach discussed in Chapter 7 for application to the identified joint-cost accounts will also apply to the depreciation expenses associated with such accounts.

Chapter 7

7. Categorization

Directions on the process to categorize costs in the cost allocation filings are presented in this Chapter.

7.1 Introduction

The categorization step, also referred to as “classification”, consists of subdividing distribution assets and O& M expenses into the following cost-based groupings:

- demand-related, and/or
- customer-related.

Distribution assets and distribution operating and maintenance expenses are classified into demand and customer-related components based on their cost causality characteristics. Generic minimum system results (stratified by density) will be incorporated into the filing model to divide joint costs into their customer and demand-related proportions.

Once categorized, the costs will be allocated to various rate classifications using the specific allocators discussed in Chapters 8 to 10.

7.2 Direction – Identification of Accounts

For the cost allocation filings, functionalized grouped costs will be ultimately classified into one of the four components:

- 100% demand-related
- 100% customer-related
- joint related (both customer and demand-related)
- pro-rata related to other costs.

Certain functionalized costs are classified entirely as being demand or customer-related (see Appendices 7.1 and 7.2 respectively for complete listings). For instance, metering, billing and collection are entirely categorized as customer-related, while distribution stations are entirely categorized as demand-related costs.

Certain distribution assets and related O&M expenses (see Appendix 7.3 for a complete list) are categorized as jointly demand and customer-related.

These are expenses that are incurred to provide service to a customer and are also required to meet customer demand. The customer component of such accounts is that portion of the expenses or the assets that vary with the number of customers. As an example, the number of poles and transformers on a distribution system varies, in part, with the number of customers served by the distributor. But these items also provide capacity on the distributor's system to meet demand.

With regard to pro-rata related accounts (see Appendix 7.4 for a complete listing of accounts and allocators), in most cases operation and maintenance (O&M) accounts support a specific type of asset class. n such circumstances, the O&M accounts are generally categorized to demand and customer components consistent with the method used to categorize the assets that are supported by the O&M account. However, there are a few other cases where the O&M accounts support a large number of assets and these accounts (e.g. Account 5005 - Operation Supervision and Engineering) are categorized on a pro-rata basis consistent with the method used to categorize these assets.

Items such as General Plant, Administration and General Expenses, Miscellaneous Revenue, Payment in Lieu of taxes ("PILs"), Return on Debt, and Return on Equity are generally not categorized but are allocated to each rate classification using the allocation methods (for example pro rata to net fixed assets or O&M) outlined in Chapter 10 – Allocation of Other Costs.

7.3 Categorization of Joint Related Assets and Expenses into Demand and Customer Portions

7.3.1 Background

Three principal options for categorizing joint distribution assets and operating expenses were initially identified. Each approach has been approved by various regulators across North America. The minimum system approach is ultimately favoured for use in the filings as the common categorization method. This will be the sole categorization method used in the model for classifying joint costs. The basic customer method will also be used in the model but for the separate purpose of calculating lower end customer unit costs to assist with future rate design.

Option 1: Zero Intercept Method

The zero intercept method uses a statistical calculation to determine the amount of distribution costs that should be categorized as customer-related versus demand related. The zero intercept method seeks to identify that portion of plant related to a hypothetical no load or zero intercept situation. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero intercept is the customer component. Due to the difficulties in using and interpreting this statistically-based method, it will not be adopted as the filing methodology for distributors.

Option 2: Minimum System Method

The minimum system method assumes that a minimum-size distribution system can be built to serve the minimum load requirements of the customer. The minimum system method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the distributor. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and the customer-related costs.

There are various approaches to define the minimum system. Moreover, judgment is required to address various implementation details with this methodology. The present Report did not seek to develop a common minimum system methodology for use by the Ontario electricity distribution sector. Instead, as explained below, the results of numerous past Ontario minimum system studies were examined and stratified generic results approved for incorporation into the filing model.

The minimum system is capable of carrying a small amount of demand, and, if unaddressed, this can contribute to the minimum system approach tending to generate a higher customer-related component than the zero-intercept approach.

To address this concern, and thus promote overall cost causality, a Peak Load Carrying Capability ("PLCC") adjustment will be made to the generic minimum system results. A further discussion on the PLCC adjustment, which has been implemented in various past Ontario cost allocation studies, is provided below.

Past empirical work in Ontario led to the development of a "modified" minimum system approach in which the traditional demand component was further split into demand and energy. For simplicity, the current cost allocation process will assume that distribution assets and expenses are classified as either demand or customer-related. This is also consistent with common North American practice.

Option 3: Basic Customer Method

This approach categorizes as customer-related costs only those capital and operating expenses that are directly associated with adding another customer. Examples of such costs are the capital and operating costs associated with meters and service drops.

There is a key difference between this method and the two discussed above. The zero intercept and minimum system methods both take into account some portion of the capital costs of the upstream distribution infrastructure, such as transformers and primary conductors. The basic customer method effectively adopts a short-term view of cost causality and does not take into account the expenses incurred to build the upstream distribution system over time.
This approach will not be approved as the categorization method for cost allocation purposes.

One of the additional goals of the filings, however, is to produce unit cost information which will be helpful as a factor to consider in the future review of fixed monthly customer charges. The basic customer method, which is used in various U.S. jurisdictions, is considered useful to build into the filing model to create a lower end customer unit cost per month for each rate classification. There are alterative methods to implement a basic customer calculation (these are reviewed in Chapter 12) and two will be chosen for modeling purposes to provide the Board with a broad range of information.

7.3.2 Direction – Use of Minimum System Method and Basic Customer Method in Filings

For cost allocation purposes, the minimum system approach will be used as the common categorization method. Generic minimum system results will be set out below for use in splitting joint costs into their respective customer and demand-related components. A standard PLCC adjustment, as described below, will also be made. The model will incorporate all of these elements.

The minimum system results will be used when the model calculates revenue to cost ratios for each rate classification. This will be the only categorization method employed for such purposes.

To assist with a future review of fixed monthly customer service charges, the model will also produce unit costs per customer per month for each rate classification (see Chapter 12 for details). The basic customer method will be used to establish the lower range of such unit costs. Two versions of that calculation will be included in the model. The customer costs resulting from the minimum system approach, as adjusted for PLCC, will be used to establish the upper range of the customer unit costs.

7.4 Generic Minimum System Approach

7.4.1 Introduction

The cost and time to undertake individual minimum system studies is significant. In addition, practitioners have varying judgements on key implementation details.

Therefore, on the grounds of both practicality and consistency, generic minimum system results will be incorporated into the cost allocation filings.

All distributors will be grouped into high, medium or low density groupings, and separate generic minimum system results provided for each grouping.

The generic minimum system results will be applied to the following joint-cost accounts:

- Line Transformers (Account 1850)
- “Distribution” which includes poles and conductors, and is defined as Accounts 1830 -1845
- Related O&M accounts.

The generic minimum system results will also be applied to depreciation accounts associated with the various asset accounts identified above.

The generic minimum system results are applied to the primary and secondary sub-accounts of the asset accounts and not to the bulk sub-account associated with the identified accounts.

7.4.2 Common Categorization Factors

7.4.2.1 Background – Past Ontario Studies

Past Ontario minimum system results were reviewed in detail. Some of the individual studies examined were undertaken as far back as the mid-1980’s. Consultations indicated that the cost causality features of distribution system design have not varied dramatically over that period, so that the past Ontario minimum system results are considered to remain useful guides. They are summarized in Appendix 7.5.

The medium and high density results reflect several minimum system studies. The rural density results are based on a single, older Ontario Hydro study.

7.4.2.2 Direction – Generic Minimum System Results in Filings

The following generic categorization percentages will be built into the filing model:

Low-density distributor:

line transformers	60% customers/40% demand
distribution	60% customers/40% demand

Medium-density distributor:

line transformers	40% customers/60% demand
distribution	40% customers/60% demand

High-density distributor:

line transformers	30% customers/70% demand
distribution	35% customers/65% demand.

7.4.2.3 Background - Stratification of Generic Minimum System Results

Technical Advisory Team discussions took place on how to fairly and consistently define density for purposes of the cost allocation filings. The question is of practical importance as the density stratum a distributor is assigned to will affect the calculation of both the revenue to cost ratios and the customer unit cost upper range.

It was noted apparent inconsistencies are evident in how density is calculated by various distributors in their RRR filings. The new common definition of density adopted below is intended to promote greater consistency for cost allocation purposes.

It cannot be confirmed beforehand that the methodology set out below will address all potential concerns about the appropriateness of the density measurement employed, and this caution should be added to the other modeling qualifications when interpreting the cost allocation filing results.

A stakeholder suggested using circuit km rather that road km as the basis for determining customer density. This suggestion was rejected because it was thought that dealing with the additional complexities of measuring circuits as opposed to roadways would not provide a worthwhile benefit. Using road km in this application provides a much easier and consistent means of measuring the relative density across distributors.

The Board may be asked to consider refinements to the minimum system density definitions or stratum boundaries in the future. One stakeholder has suggested that a mechanism to smooth the transition between density stratum boundaries be considered.

7.4.2.4 Direction – Density Thresholds and Measurements for Cost Allocation Filings

For purposes of stratifying the generic minimum system results used in the cost allocation filings, 30 customers per kilometre will be the dividing line between a low and a medium density distributor, and 60 customers per kilometre will be the dividing line between a medium and a high density distributor.

For a distributor that used a historic test year in the 2006 EDR process, the above should be calculated using 2004 data. A distributor that based its 2006 rate filing on a forward test year should use the most up-to-date actual data available.

To promote greater consistency in the determination of the appropriate minimum system density stratum employed for a distributor's cost allocation filing, the following common density measurement methodology must be employed:

- To determine line length (i.e. not per circuit length since there can be multiple circuits per line), the distributor should consider the distance along the road the lines travel. As only road distance will be considered for line length, a double pole line going down both sides of the road for 2 kilometres should be considered as 2 kilometres and not 4.

- The number of customers will not include any customers or connections that are unmetered (i.e. streetlights, sentinel lights and unmetered scattered loads). This is considered a helpful approach for the present test only, and a different definition of "customer" will be used elsewhere in the filings.

If a distributor can document reasons to justify classification into another density stratum*,* an explanation along with supporting documentation should be provided in the Filing Summary and the distributor should file a Run 3 of the model using the generic minimum system results for the alternative density stratum proposed.

Regardless of whether a distributor has one or more density-based rate classifications, a single minimum system result will apply to the whole distributor. The allocation process to deal with the different density rate classifications is set out in Chapter 11.

7.4.3 Filing Questions

The Board is interested in understanding certain factors that could impact interpretation of the minimum system results. The following filing questions must be answered:

- If the distributor is an urban utility, does the distribution system have a large downtown secondary network system? If yes, provide a brief description.

- Does the distributor have a significant underground distribution system? If yes, provide a brief description.

- If the distributor is a low density distributor for filing purposes, consider and advise if there is any factor(s) which may lead to the low density generic minimum system result not being reasonably reflective of the specific system's characteristics.

7.5 Peak Load Carrying Capability ("PLCC") Adjustment

7.5.1 Background – PLCC Adjustment

The minimum distribution system will carry a small amount of demand. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations.

Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each classification is allocated demand costs based on the total classification's non-coincident peaks. As such, it has been argued that a classification's non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating or double-counting demand can be achieved by the application of a PLCC adjustment. This adjustment will determine how much demand for a rate classification can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the classification's non-coincident peak demands used for determining demand allocators. The adjusted classification's non-coincident peaks can then be used to allocate the distributor's demand-related costs, eliminating the double-counting. The number of customers/connections used for the PLCC should match the number of customers/connections used to allocate the customer component of the distributor's capital and O&M costs associated with poles, conductors and transformers.

Implementing a PLCC adjustment will be consistent with past Ontario cost allocation studies. The Technical Advisory Team reviewed past Canadian studies and found the results of the peak load carrying capability adjustments undertaken ranged from 0.2 kW to 1.0 kW per customer/connection. The suggested PLCC adjustment of 0.4 kW per customer or per connection is approved by the Board as a reasonable figure for a generic adjustment. Furthermore no adjusted demand should be below zero.

One stakeholder questioned why a zero threshold was included for adjusted demand. Another stakeholder proposed that a larger PLCC adjustment be made for larger users. The theoretical underpinnings of the minimum system analysis turn on all customers paying equally (on a per customer basis) for the minimum distribution system-related costs. Giving one class a bigger PLCC credit or reducing distribution cost allocations via a negative non-coincident demand allocator would violate this higher principle embodied in the minimum system concept. Therefore the Board will not follow these stakeholder comments.

As no single definition of an approved minimum system methodology has been adopted, no distributor-specific PLCC adjustment will be allowed unless a distributor first conducts it own minimum system study.

7.5.2 Direction – PLCC Adjustment

The cost allocation filings must incorporate a common PLCC adjustment of 0.4 kW per customer or 0.4 kW per connection. The details will be built into the filing model.[11]

Cost Allocation Adjustment

The PLCC in kW per customer or per connection should be multiplied by each rate classification's number of customers or connections. For the purposes of the PLCC adjustment, the model will first consider if there are connections assigned to the rate classification. If this is not the case, the number of customers for the rate classification will be used. The product of 0.4 kW per customer/connection and the number of customers/connections will determine how much of the classification's demand is met by the minimum system. This demand capacity is then subtracted from each classification's non-coincident peak at primary and secondary assets. The adjusted non-coincident peaks at primary and secondary are then used to allocate a distributor's capital and O&M costs for poles, conductors and transformers. This adjusted demand cannot be lower than zero. No PLCC adjustment is appropriate for bulk delivery facilities, including a distribution station that has been classified as bulk ,as there are no customer-related costs associated with such facilities.

The number of "customers" associated with street lighting and unmetered scattered loads typically are based on the number of connections each group has on the distribution system. For street lighting and unmetered scattered loads, the number of connections for these customers will be used to determine the PLCC adjustment for these customers. It is expected that when these customers are in a separate rate classification, in some cases the PLCC adjustment will reduce the demand allocator to zero and thus no demand-related costs associated with the minimum system will be allocated to the rate classification. This is considered a reasonable outcome, as there are a number of cases where the connection will use less than 0.4 kW of load.

[11] The adjustment will be made to the minimum system results.

Customer Unit Cost Adjustment

Another output of the filing model is customer and demand unit costs by rate classification. These unit costs can be used to help set future distribution rates; however, to reflect the results of the PLCC adjustment, an appropriate amount of customer-related costs should be moved into the demand-related costs before rates are determined. This unit cost adjustment will be incorporated into the cost allocation model. Note the adjustment will not change the total cost allocated to the rate classification.

Distributor-specific PLCC Adjustment

If, and only if, a distributor files its own minimum system study, it must also file and explain its own PLCC adjustment.

7.5.3 Filing Question

If any distributor suspects its generic minimum system result and/or the generic PLCC adjustment has contributed to an anomalous filing result for a rate classification, an explanation should be included in the Filing Summary.

7.6 Distributor-Specific Minimum System Study

7.6.1 Background

One distributor undertook a new minimum system study at the time of unbundling and has asked whether these results may be used in the present filings. A similar issue would arise if a distributor completed a new minimum system study before its scheduled filing date. The Board cautions, however, that the use of the approved generic minimum system results is encouraged to make the overall filing and review process more efficient. As the generic results are considered reasonably reliable, delays in filing based on non-mandatory further minimum system analyses are undesirable.

7.6.2 Direction – Use of Distributor-Specific Minimum System Study

While use of the generic minimum system results is encouraged for these filings, if a distributor does undertake a new minimum system study before its filing date, then the distributor may use such minimum system results in Run 3 of the cost allocation model to be filed.

If a distributor has an existing minimum system study that was completed during or after its distribution rates were unbundled, then it may use these results in Run 3 of the cost allocation model to be filed.

Any distributor that uses its own minimum system study must also provide the following in its Filing Summary:

- the date of its minimum system study
- a general description of the methodology used
- the definition and size of the “minimum” system assumed in the study
- the treatment of overhead and underground assets
- the treatment of any large urban network systems
- where the distributor amalgamated with another distribution company since the original minimum system study was completed, has the study been updated to reflect the amalgamation?
- the PLCC methodology followed and size of adjustment proposed.

The Filing Summary should include discussion of the materiality of the difference in filing results from use of the generic minimum system figures versus the utility-specific study.

7.7 Multi-unit Dwelling Adjustment(s)

7.7.1 Background

The minimum system methodology to be adopted will allocate certain customer-related costs to individually metered customers in multi-unit complexes. But the multi-unit complexes have sometimes been considered, in past studies, as single customers for minimum system cost allocation. A stakeholder suggested that a multi-unit adjustment is justified on cost causality grounds for other items in the studies as well. It was also suggested that such an adjustment could be implemented in future cost allocation studies without the need to create further rate classifications.

No adjustments for multi-unit dwellings will be included in the present cost allocation filings since it is understood it can be difficult for distributors to ensure that their load data and the customer/connection information properly reflects multi-unit complexes. The Board considers it important that the filings gather further information about this issue to facilitate future improvements to the cost allocation methodology. Distributors are expected to undertake reasonable efforts to gather the estimates requested below.

7.7.2 Filing Questions

The following questions must be answered in the filings.

1. Estimate the number of individually metered Residential customers who reside in multi-unit dwellings and the number of distributor connection points which supply the multi-unit complexes.
2. Estimate the number of individually metered General Service customers that are located in multi-unit complexes and the number of distributor connection points which supply the multi-unit complexes.
3. Estimate the number of individually metered mixed use customers (i.e. Residential and General Service).
4. Some multi-unit connection points are served at primary voltage. This will impact the allocation of transformer costs and credits and the allocation of Services costs. In order to determine the extent of this issue, the distributor should estimate how many of the multi-unit connection points are at primary voltages and how many at secondary voltages for both residential and general service complexes.

Chapter 8

8. Allocation of Demand-Related Costs

Directions on how to allocate demand-related costs in the cost allocation filings are presented in this Chapter.

8.1 Introduction

The accounts/sub-accounts that, following the categorization step, are allocated on demand in total or in part were listed in Appendices 7.1 and 7.3.

There are several technical factors to consider when properly allocating the demand-related component of distributor costs. Some distributor assets are designed to meet the individual customer's maximum demand, while other assets are built to meet the aggregate or diversified maximum demands of many customers.

Two approaches will be used when allocating demand-related costs:

- Coincident Peak ("CP") is the demand of any customer classification at the time of the distributor system peak.
- Non-Coincident Peak ("NCP") is the peak demand for a customer classification regardless of the time of occurrence.

Specific directions are set out below as to the appropriate use of CP and NCP.

In past cost allocation studies, use was also made of Individual Class Non-Coincident Peak ("NCPI"), which is the sum of the peak demands of individual customers within a classification regardless of the time of occurrence.
In order to maintain ease of preparation and review, and as other methods are used to allocate some of the underlying costs, NCPI will not be used in the filing methodology.

8.2 Non-Coincident Peak ("NCP") Method

8.2.1 Introduction

Some version of NCP is generally used in Canada to allocate most demand-related distribution costs. The reasons include:

- In most cases, distribution assets are sized to meet the maximum demand for a group of customers and not the system coincident peak of the distributor.
- NCP allocates a fairer share of demand-related costs to rate classifications that use the assets but which may not be consuming much electricity at the time of the system coincident peak.
- Customers have better control over their NCP than over their CP.

8.2.2 NCP Options

8.2.2.1 Background

There are various specific forms of a NCP allocator and stakeholder discussions focused on the merits of the following:

- 1 NCP - This option involves the use of highest monthly non-coincident demand peak.
- 4 NCP - This option involves the use of the average of the four highest monthly non-coincident demand peaks.
- 12 NCP - This option involves the use of the average of the 12 monthly non-coincident demand peaks.

1 NCP

1 NCP is the most common version of NCP used in other jurisdictions. It is a widely-held view amongst stakeholders that the demand capacity of a distribution system is generally designed to handle the greatest single peak whenever that may occur.

Local load data experts have cautioned in both the 2003 and 2006 consultations about the reliability of using 1 NCP as the main demand allocator for cost allocation, given the limited length of time for which updated load data was collected. Therefore, as a practical matter, the Board concludes 1 NCP should be used only where a pronounced peak can be confirmed through the available load data. It is considered reasonable to believe that this pronounced peak requirement will address concerns about the reliability of the load data collected. An appropriate test set is set out below.

A stakeholder comment raised the question as to whether the Board should mandate collection of multiple years of load data if and when cost allocation is undertaken again. The Board notes the helpful suggestion and will consider the merits sometime in the future.

4 NCP

A criterion accepted in prior Ontario cost allocation analyses is the importance of choosing a stable cost allocation methodology. 4 NCP will function as a more stable methodology than 1 NCP and so has an important practical advantage in this regard. In addition, 4 NCP will not blunt cost causality to the same degree as 12 NCP. As such, it will be the starting point of the common demand allocator adopted.

The intended policy objective here is not to promote rate stability *per se* for any given rate classification, but rather to adopt a method for general use that will not lead to widely differing results if a single data point is used and proves not reliable. The issue is particularly important in Ontario as detailed load data research has recommenced after a number of years in abeyance. Also, the common filing requirements must take into account the wide variety of circumstances amongst distributors across the Province (for example, where distributors are summer and winter peaking, use of 1 NCP may lead to unstable results over time under some circumstances).

More detailed analysis also suggests accurately tracking cost causality may be complex in some distribution systems and therefore 1 NCP should not be assumed to best reflect cost causality in all circumstances.

12 NCP

It is understood that 12 NCP was the demand allocator used when historic bundled rates were set under the former regulator. The technical case for use of 12 NCP was clearer in the past when generation costs were part of the bundled costs to be allocated. In an unbundled environment, use of 12 NCP in other jurisdictions is uncommon. Thus use of 12 NCP in either Run 1 or Run 2 of the filings is not permitted.

Stakeholders cautioned that customers that are more weather sensitive (residential, seasonal, and farm classification customers in particular) could be adversely impacted if 1 NCP were preferred over 12 NCP. The Board believes that the present filings should be based on a sound cost allocation methodology, and that adverse impacts on particular customers would be better raised later when new rates are considered for implementation.

For the purpose of determining the rate classification to which a customer is assigned, the Board has adopted the use of a customer's average 12 month NCPI. In this context, the merit of using 12 NCPI is to protect the customer from frequent rate reclassification. However, the main objective of the cost allocation studies is to reliably reflect cost causality in the costs allocated to the various rate classifications, and the Board believes this will best be achieved by using a combination of 1 NCP and 4 NCP. Use of 12 NCPI (or 12 NCP) may unduly mute cost causality for cost allocation purposes.

Use of 12 NCP in the Run 3 will not be allowed unless the distributor also provides supporting justification in the filing based on the cost characteristics of its distribution system. The use of 12 NCP is not expected to be common.

8.2.2.2 Direction - Tests for Use of NCP in Filings

NCP will be the demand allocator used when allocating assets identified by a distributor as primary or secondary assets.

4 NCP will be the starting point for the common demand allocator to be used in the cost allocation filings. But 1 NCP will be used where the NCP test, outlined below, confirms the existence of a stable, "pronounced" peak. The test has been designed so that a peak in the highest month that is greater than 20 percent of the average of the highest four months will lead to use of 1 NCP rather than 4 NCP.

The following test, which will be incorporated in the cost allocation model, will be used to determine which version of NCP to use when allocating primary and secondary assets:

$$\text{NCP Test} = \frac{(A + B + C + D) / 4}{A}$$

A = sum of the highest monthly NCPs for all rate classifications
B = sum of the second highest monthly NCPs for all rate classifications
C = sum of the third highest monthly NCPs for all rate classifications
D = sum of the fourth highest monthly NCPs for all rate classifications.

A, B, C and D will be provided by the distributor's load data service provider.

An NCP test result of 83 percent or greater indicates that the distributor must use a 4 NCP method for allocating demand costs. In the event of a test result lower than 83 percent, the 1 NCP method must be used. For example, if A = 100 and B, C, and D are 78, then 4 NCP would be chosen as the average of the four amounts is 83.5 and test result would be 83.5 percent. In this case A, the peak month, is not greater than 20 percent of the average of the four months (i.e. (100/83.5 - 1) = 19.7 percent). However if B, C, and D are 77 and A remains at 100, then 1 NCP would be chosen, as the average of the four amounts is 82.8 and the test result would be 82.8 percent. In this case, the peak month is greater than 20 percent of the average of the four months (i.e. (100/82.8 - 1) = 20.8 percent).

The above methodology must be followed by all distributors in Run 1 and Run 2 of the filing.

A distributor may use 12 NCP in its optional Run 3, provided that the distributor also provides supporting justification in its Filing Summary based on the cost characteristics of its distribution system. In such cases, the Filing Summary should highlight the impacts of the different NCP allocator used in Runs 1 and 2, versus Run 3.

8.3 Coincident Peak ("CP") Method

8.3.1 Background

CP is the generally preferred demand allocator for distribution assets designed to serve a distributor's system peak. In the cost allocation filings, assets identified as >50 kV and bulk (if any)[12] by a distributor must be allocated based on CP.

The Federal Energy Regulatory Commission has developed various tests to determine the appropriate CP to be used when allocating transmission costs. This approach has been adapted for use in the current cost allocation filings. The test below has been designed so that a 20% peak will warrant use of 1 CP rather than 4 CP. The type of CP allocator used can impact the cost allocated to a rate classification. For example, street lights may benefit from 12 CP as opposed to 1 CP under certain circumstances.

8.3.2 Direction - Tests for Use of CP in Filings

For distribution assets and related O&M accounts that are solely designed to meet the distributor's system demand, CP will be used as the demand allocator. For the filings, this will consist of all costs related to >50 kV and bulk assets (if any).

CP for each rate classification will be further subdivided into transmission transformation CP ("TCP") and distribution CP ("DCP"). Transmission transformation CP represents the coincident peak of all customers that use the >50kV assets deemed to be distribution assets.

The choice of 1 CP, 4 CP or 12 CP will be determined by the application of the test described below. As with the NCP test, the CP test will be incorporated into the filing model.

[12] See Chapter 6 (for example, guidance is provided there as to when a distribution station serves a bulk function and therefore its costs should be allocated using CP).

CP Test #1

This test calculates the average of the twelve monthly system peaks as a percentage of the highest monthly system peak as follows:

> CP Test #1 = Average of 12 Monthly System Peaks ÷ Annual System Peak.

A CP Test #1 result of 83 percent or greater indicates that the distributor must use the 12 CP method for allocating demand costs that are to be allocated on a CP basis. If the test result is less than 83 percent, CP Test #2 must be conducted.

CP Test #2

This test calculates the average of the four highest monthly peaks as a percentage of the greatest monthly peak as follows:

> CP Test #2 = Average of the 4 highest Monthly System Peaks ÷ Annual System Peak.

A CP Test #2 result of 83 percent or greater indicates that the distributor must use the 4 CP method for allocating demand costs.

A CP Test #2 result of less than 83 percent indicates that the distributor must use the 1 CP method for allocating demand costs.

8.4 Measurement of Peak for Demand Allocation

8.4.1 Background

Using a one hour (i.e. clock hour) measurement of peak is the most common approach when determining the demand allocator for electricity sector cost allocation studies. A few jurisdictions (for example, Manitoba) use a longer period. It is considered that use of a one hour measurement period of peak, along with the use of the above-mentioned 4 NCP/1 NCP test, will provide an appropriate balance of policy objectives.

8.4.2 Direction – Measurement of Hourly Peak for NCP and CP

For cost allocation purposes, the definition of peak for NCP or CP will be the standard one hour (clock hour) measurement of the peak hour. The use of a rolling 15 minute window for measuring peak will not be permitted.

8.5 Allocation of Benefits of Diversity

8.5.1 Background

When customers with differing consumption patterns are pooled into a customer classification, this results in the sharing of the benefits of the diversity of their consumption patterns. These benefits arise because the classification's peak will be lower than the sum of the individual customer peaks. This means that the demand allocation of costs to that classification will be lower than if the allocator were based on the sum of the individual customer peaks.

There are two possible approaches to sharing the benefits of diversity:

i) where diversity is shared within each separate rate classification (i.e. "class" or "subclass"); or

ii) where the diversity is shared within a given class, and the sub-classes that collectively form the main class share the benefits of that class diversity on a pro-rata basis.

It is understood that approach i) is more generally used for cost allocation purposes by electricity utilities in other jurisdictions. Furthermore, consultations indicated it was challenging to agree where to place each rate classification under approach ii). On the other hand, some stakeholders suggested that approach ii) is more consistent with certain aspects of past Ontario rate design practice. Reference was also made to the distinction between class and subclass raised during the 2006 EDR process. A stakeholder also suggested that approach ii) is particularly suitable for density-related subclasses.

On balance, the Board considers the use of approach i) preferable for the cost allocation filings because of greater simplicity and consistency with general North American cost allocation practices.

Whether Unmetered Scattered Loads and Load Displacement Generation are to be treated as fully separate rate classifications with their own load data profiles, or as adjustments to the charges of an existing rate classification, will have implications for the overall sharing of the benefits of diversity. The proper treatment of diversity amongst load displacement generation customers attracted further stakeholder comments and is addressed in Chapter 11.

8.5.2 Direction – Separate Treatment of Each Rate Class and Subclass For Cost Allocation Purposes

Each "rate classification" (i.e. class or subclass) will be treated as independent and separate for cost allocation modeling and load data requirement purposes.

Diversity will be shared within each separate rate classification (e.g. GS<50 kW and GS>50 kW) and not between any rate classifications.

For charges that are based on adjustments to the rates of a main classification (such as most Run 1 USL and LDG rates), diversity will be shared between those customers and the main classification with which they share demand costs.

The above Directions are for cost allocation purposes only, and are not intended to prejudice any future policy discussions on rate design issues that may be impacted by a full resolution of the class versus subclass distinction. Some stakeholders have argued, for instance, that boundary smoothing mechanisms are especially appropriate when a customer shifts from GS<50 kW to GS>50 kW if it is considered they represent subclasses.

8.6 Line Losses

8.6.1 Background

There is presently an approved methodology for treating line losses, which makes some distinctions regarding the line losses to be assumed by each rate classification.

The rate order for a distributor generally has two Total Loss Factors (TLF), one for customers whose meter is on the secondary side of the line transformer, and one for customers metered on the primary side. Nearly all customers are “secondary metered”. The TLF for secondary metered customers is 1% higher, reflecting the losses that are assumed to have occurred in the transformer. Distributors with Large Use customers have an additional pair of TLFs, imputing only the losses in the transformer station and the next step-down transformer. The terms “primary” and “secondary” are also used for the Large Use TLFs, again to recognize whether the customer is metered on the high side or low side of the local transformer.

A few distributors have additional TLFs in the approved rate order***.*** The main example would be a host distributor with a TLF for the embedded distributor, where this is distinguished from the TLF for its Large Use customers. There may be other examples as well, arising from the particulars of the distributor’s 2006 EDR application.

At present, the lower TLF applicable to Large Use customers provides some recognition of the fact that they do not use the lower voltage system, and that they do not pay for the losses which occur in that part of the system.

Note the words “primary” and “secondary” are used in the rate order in a different way than they will be used in the cost allocation filings. While not specifically designed for cost allocation purposes, the approved TLF for secondary, primary and large use does provide some level of segregating line losses among differing uses.

Stakeholders discussed if further segregating line losses into bulk, primary, and secondary functions might allow line losses to be allocated in a more refined manner, and the costs and benefits of doing so. The view was that the net benefits would be modest and a full analysis of the topic complex. The Board prefers that the status quo treatment of line losses be used for the present filings.

Filing questions will be asked below to gather further relevant information to assist with any future refinements considered in allocation of line losses between rate classifications.

8.6.2 Direction – Treatment of Line Losses in Filings

In the cost allocation filings, distributors will use the same loss factors as approved in their 2006 EDR applications when adjusting their metered load data to arrive at the demand allocators.

8.6.3 Filing Questions

A distributor must provide the following information for future reference as part of its Filing Summary:

1. Provide an estimation of "non-technical" energy losses (e.g. theft of power, billing accruals, metering problems) as a percentage of energy purchased

2. Provide an estimation of technical distribution system energy losses as a percentage of energy purchased. The sum of technical and non-technical losses is the total measure of distribution losses.

3. Provide an estimation of the technical line losses broken out according to the following major system components: > 50 kV, bulk, primary and secondary assets. Please use the same definitions as in the cost allocations filings.

Chapter 9

9. Allocation of Customer-Related Costs

Directions on how to allocate customer-related costs in the cost allocation filings are presented in this Chapter.

9.1 Introduction

Customer-related costs are commonly allocated by using the number of customers by rate classification, or by using weighted customer allocation factors. The weightings of customer allocation factors are typically developed by taking into consideration, in addition to the number of customers, factors such as investment costs (for example, for metering and service drops), and the level of effort and complexity involved in providing service to the various customer groups.

The weightings of allocation factors generally vary by asset and type of O&M expense to better reflect their specific cost characteristics. For instance, the relative proportion of the cost allocated to a particular rate classification may vary depending on the type of asset or service (for example, metering equipment compared to service drops). In the case of meter reading, the weighted allocation factors would typically take into consideration the meter reading frequency per rate classification, as well as customer density.

9.2 Definition of Customer and Connection for Filings

The accounts/sub-accounts that are allocated based on the number of customers or connections in total or in part were listed in Appendices 7.2 and 7.3.

For the purpose of the cost allocation filings, a "customer" is generally defined[13] by a meter point that measures energy consumed over a period of time.

For unmetered loads, the number of connections will be used to allocate some customer-related costs. For street lights, sentinel lights and unmetered scattered loads, the number of connections will be the actual number of devices.

In the case of street lights, one "connection" frequently links a number of fixtures to the distribution system and simply using the number of devices may overstate the number of physical connections to the distributor's system. Therefore, where

13 A specialized definition of "customers" will be used when determining the number of customers that use bulk, primary and secondary assets (see Appendix 6.2: Identification of Customers Served at Bulk, Primary and Secondary).

better information is available, distributors must apply a connection factor to the number of streetlight fixtures for the purpose of determining the customer allocation factor.

9.3 Allocation of Customer-Related Costs

9.3.1 Billing Activities

9.3.1.1 Background

A common allocator used to allocate customer-related costs that are related to billing activities is the number of bills issued. The major accounts allocated on this basis are billing, collecting and associated supervision, and customer care costs. Within billing, this includes postage, stationary and handling expenses. Within collections, this includes payment processing expenses per bill payment remitted.

Some parties proposed that weighting factors be applied to the number of bills to reflect the differences in the costs for preparing and validating the bills for different customer classifications. The Board agrees.

Default weighting factors were developed for the major rate classifications based on a survey of the factors used in other jurisdictions and the comments received from stakeholders. Stakeholders raised questions about how to treat rate classifications not addressed in the survey, and use of utility-specific weighting factors. As a result of these concerns, flexibility has been provided in the directions below.

Since billing costs are not recorded in separate accounts, they may be difficult to isolate. These costs may also be recorded differently across distributors. Creation of separate accounts which are recorded consistently could be considered for recording these costs. In the future, as a more detailed understanding of these costs is obtained, this could lead to more refined cost allocation for costs such as CIS, call centre and key account expenses (for example, an activity-based approach could be discussed).

9.3.1.2 Direction – Allocation of Billing Activities

The number of bills adjusted by a weighting factor must be used to allocate costs associated with billing activities which include billing, collecting, and associated supervision and customer care costs. For the purposes of the cost allocation filings, billing activities will also include CIS, call centre and key account expenses.

A "bill" is defined as an invoice sent to a customer that includes the charges for distribution services. One way of calculating this number is by applying the billing frequency for one year by the test year customer numbers used in the 2006 EDR model. For rate classifications that are billed on a consolidated basis, the basis for the allocation is the number of bills. For further discussion, see Chapter 11.

The weighting factors shown in Appendix 9.1 should be used as the default factors for billing costs for the rate classifications indicated. To provide flexibility in the application of weighting factors:[14]

i) A distributor should enter distributor-specific weighting factors into the cost allocation model, if its actual billing cost factors per rate classification are materially different (i.e. differ by 10% or more compared to the defaults) and supporting information is available (a summary must be filed).

ii) If a weighting factor is not provided for a particular rate classification, it should be assumed the factor will be 1.0, unless a distributor develops and documents another weighting factor. Such an alternative weighting factor should be undertaken if the data is available and the difference in weighting factors to be used is significant.

iii) A distributor can further refine its weighting factors to include the proportion of the rate classification which is interval metered and/or subject to metering multipliers. In such a case, the distributor should determine the composite weighting factor for the rate classification and enter the factor in its cost allocation model.

In most cases, the charges for sentinel lights appear as one line on the standard bill of a Residential or General Service customer (which is typically a bill with 10 lines). As a result, for cost allocation purposes each sentinel light should represent 10% of a standard Residential or General Service bill, which means the weighting factor for sentinel lights will be 0.10. This adjustment will need to be made by the distributor to the "number of bills" for sentinel lights to be entered in the cost allocation filing model.

Some distributors may have better information to allocate costs associated with billing activities to each rate classification. In such cases, these distributors must use this better information in all runs of the cost allocation filing and provide an explanation and support of the alternative allocation methodology in the Filing Summary.

[14] The distributor's Filing Summary should discus if the adjustments described below are followed.

9.3.1.3 Filing Questions

The following questions must be answered:

1) Identify under what accounts expenses associated with the following activities are included: Call Centre, Customer Information System, Key Accounts and Payment Processing.

2) Indicate the percentage of each cost in the account in which it is embedded.

9.3.2 Meter Capital Costs

9.3.2.1 Background

The capital costs associated with metering vary according to the type of metering device installed. For the Residential and General Service rate classifications, the most common type of metering device is the electromechanical induction meter. In contrast, larger use consumers generally have interval meters. For cost allocation purposes, metering capital costs will include capital costs and depreciation. Related operating and maintenance expense will be allocated on the same basis.

It is appropriate to use a weighted number of meters to allocate the costs associated with meter capital between rate classifications. A weighted number of meters takes into account both the number of metering points and the capital costs of the applicable metering devices for each customer rate classification.

The Technical Advisory Team developed standard installed costs per meter. Information on installed costs per meter for common meter types was provided by some distributor members. Current costs were used and considered acceptable because only the relative ratios are being used. It is believed that the resultant relative costs of installed meters between rate classifications based on these standard meter costs is reasonably applicable to a wide range of distributors, even if the absolute dollar value of the cost of meters differs.

9.3.2.2 Direction – Allocation of Meter Capital Costs

Default installed meter capital costs will be provided for use when allocating meter capital costs. These are listed in Appendix 9.2.

A distributor will enter the estimated number of installed meters of each type within each rate classification. The total installed metering cost per rate classification is calculated within the model by multiplying the number of installed meters entered by the default cost per meter.

Note it is the number of utility-installed meters that form the basis for the allocation. Where customers have their own meters, these meters are not included in the calculation.

An allocation percentage for each rate classification is calculated by dividing the total installed metering cost per classification by the total installed metering cost for all classifications. This percentage is applied to the costs associated with meter capital to allocate these meter costs to each rate classification.

Average weighted meter costs per rate classification and weighted factors per rate classification are calculated within the model and are reported as a separate output to assist in understanding the percentage allocation calculations.

Flexibility has been built into the model to enter, for all model runs, three additional meter types and installation costs. These must be used where a meter type exists for a distributor that is materially different in cost, defined as 10% or more different from the cost of the standard meter types provided. The model defaults must be used if actual costs differ by less than 10%.

Small distributors have advised that their unit costs of acquiring certain meters may be higher than those distributors that purchase in large quantities. If the difference is material, the distributor should enter distributor-specific information into the model to better reflect its conditions.

When distributor-specific information is used in the model in lieu of the default weighting provided, an explanation and supporting detail must be included in the distributor's Filing Summary.

When counting the number of meters, for example in respect of Smart Meters, the distributor should base the count on the number of such meters installed in the test year used for 2006 EDR rates.[15]

9.3.3 Meter Reading Costs

9.3.3.1 Background

At present, the meters for most Residential and General Service < 50 kW customers are read manually. The frequency of meter readings may vary by rate classification and by distributor. It is therefore appropriate to use an allocator that reflects a weighted number of meter readings to allocate the cost of these reads. The weighted number should also take into consideration density and the meter reading frequency. For example, it is generally more expensive to read individual

[15] As a result, Smart Meters will likely be minimal for historic teat year EDR filers and more significant for future test year EDR filers. Note the latter would count as at mid-fiscal year 2006.

meters for customers that are farther apart than the meters for customers that are located in close proximity.

The majority of interval meters for the larger uses are read electronically and do not require physical meter reading.

From a cost allocation perspective, rate classifications, and customer groups within a classification, that have interval meters should not be attributed any physical meter reading costs. However, some expenses such as telephone lines and data validation may be incurred. If so, they should be allocated to these customer groups.

The Technical Advisory Team developed standard weighted factors for meter reading costs. The resulting relative costs of meter reading between rate classifications based on these standard weighted factors is considered reasonably applicable to a wide range of distributors, even if the absolute dollar amounts differ.

9.3.3.2 Direction – Allocation of Meter Reading Costs

Default "relationship factors" related to meter reading costs are provided for use when allocating meter reading costs. Details are set out in Appendix 9.3.

The cost to read a residential urban outside meter will be the base against which every other type of meter read will be compared. A relationship factor will be developed relative to that base for each type of meter read. A distributor will enter into the filing model the estimated number of installed meters of each type within each rate classification.

The relationship factors will be applied to the installed meters within a classification to determine a total "relative" cost of meter reading for the rate classification. An allocation percentage for each classification is calculated by dividing the total relative meter reading cost per classification by the total relative meter reading cost for all classifications. This percentage is applied to the costs associated with meter reading to allocate these costs to each rate classification.

Flexibility has been built into the model to allow entry of five additional meter types and meter reading cost factors. These must be used where a meter type exists for a distributor that is materially (defined as at least 10%) different in meter reading cost than the standard meter types incorporated in the model. Where a distributor does have materially better information on its meter reading costs, then this information must be included in the cost allocation model for all runs and supporting documentation must be provided as part of the distributor's Filing Summary. The defaults must be used if actual costs differ by less than 10% from the defaults provided**.**

9.3.4 Services

9.3.4.1 Background

The installed costs of overhead and underground service drops are included in Account 1855. These costs are customer related and it is appropriate to allocate the costs associated with these services (e.g. depreciation, O&M, etc.) on the basis of weighted number of customers or connections, where the weighting factors reflect the average cost of connection for each rate classification.

A survey of weighting factors that are commonly used in a number of jurisdictions was conducted during the consultations and the results circulated for comments.

Some stakeholders indicated that distributors may have different points of demarcation for the assignment of costs to the services account. It may be appropriate for the weighting factors for some rate classifications to be set at zero, since due to the distributor's demarcation policy, zero costs are incurred for services to these rate classifications. One distributor indicated that it recorded no costs in this account. In this regard, the allocation of the Services account can only be based on the weighted customer count for those customers whose services are actually reported in the account.

9.3.4.2 Direction - Allocation of Services Costs

The weighted number of customers or connections will be used to allocate costs related to Services (Account 1855). It is intended that the weightings reflect the differing average costs of connections for each rate classification. Default weighting factors are set out in Appendix 9.4.

A distributor should enter distributor specific weighting factors into the cost allocation model if their actual Services costs factors per rate classification are materially different (i.e. differ by 10% or more compared to the default values) and supporting information is available (such supporting information should be filed).

The Filing Summary should indicate if the distributor has no costs in Account 1855 and explain why.

9.3.4.3 Filing Questions

The following questions must be answered:

1) Services (Account 1855) is a significant account in the cost allocation study and it is important that the proper costs are recorded in this account. What facilities are included in this account and do these facilities match the definition in the USoA? Refer to the APH for the definition. As a distributor, if the accounting treatment is different, explain the accounting treatment of this account and estimate the impact on the account.

2) The Board is interested in understanding whether Account 1855 captures the service drops for all customer or just those service drops operated at the secondary voltages (i.e. <750 volts). In this regard, does Account 1855 capture the service drops for all customers or only the costs of service drops operated at secondary voltage (<750 volts)? Are there any distributor-owned service drops to customers served from primary or bulk facilities and, if so, where are the costs of these facilities reported?

Chapter 10

10. Allocation of Other Costs

Directions on how to allocate “other” costs in the cost allocation filings are presented in this Chapter. Generally these are costs that are neither customer nor demand-related.

10.1 Introduction

Some components of the revenue requirement cannot be directly allocated, or allocated to customer rate classifications by using the functionalization, categorization and allocation process described earlier.

Instead other methods are commonly used to allocate these costs. They include:

- an allocation pro rata to the allocated O&M
- an allocation pro rata to the allocated net fixed assets
- detailed analyses (e.g. based on rate classification historical experience).

Expenses and capital expenditures falling into this category include:

- general plant
- administrative and general expenses
- working capital allowance
- PILs, other taxes, cost of debt, and return on equity
- bad debt expense
- late payment charges and collection costs
- conservation and demand management costs.

10.2 General Plant

10.2.1 Background

General Plant includes the capital cost and depreciation (if applicable) associated with buildings, leasehold improvements, land, land rights, general computer equipment, office furniture and transportation equipment. These are not directly related to distribution but are essential to the operation of a distributor.

Costs that are classified as General Plant are commonly allocated to rate customer classifications based on a composite of the distribution net fixed assets, excluding General Plant assets, which are allocated to the customer classification. This approach is adopted in the directions below.

A stakeholder suggested that use of fixed assets, with no adjustment for contributed capital,[16] is a better measure of the scope of the assets that General Plant is supporting and therefore from a cost causality perspective should be the allocation factor used.

10.2.2 Direction – Allocation of General Plant

General Plant should be allocated on a pro rata basis using a composite of distribution net fixed assets (average of opening and closing balances for the test year), with no adjustment for contributed capital.

Distributors that have detailed analysis on the allocation of General Plant, however, must use this information in all runs of the cost allocation model filed and provide supporting explanation and documentation in the Filing Summary. For example, identifiable CIS assets could be segregated out and allocated to each rate classification in the same manner as billing and collecting costs.

10.3 Administrative and General Expenses (“A&G”)

10.3.1 Background

This category includes costs that support all aspects of the overall organization such as executive, management and general administration salaries and expenses, employee pensions and benefits, office supplies, franchise requirements and regulatory affairs.

10.3.2 Direction – Allocation of A & G

Except for property insurance and community safety program costs, a *pro rata* allocation of O&M with backing out of A&G will be the common methodology for allocating general expenses.

For property insurance and community safety programs that serve to safeguard the distributor’s assets, these costs should be allocated on a pro rata basis using a composite of distribution net fixed assets (average opening and closing balances for the test year), with no adjustment for contributed capital.

[16] Contributed capital is handled separately (see Chapter 6).

10.4 Working Capital Allowance (“WCA”)

10.4.1 Background

The working capital allowance forms part of rate base and is the working capital deemed to be required by a distributor to support its operations. For 2006 rates, in most cases the WCA for electricity distributors is 15% of the sum of the cost of power (COP) and certain distribution expenses excluding depreciation. There is one distributor that does not use 15%, but has another Board-approved percentage that is based on a specific lead-lag study.

10.4.2 Direction – Allocation of WCA

The COP component will be allocated based on energy. The COP component of working capital should be broken out into transmission-related and non-transmission–related components. The transmission-related component should be allocated to all customers. The non-transmission-related component should not be allocated to wholesale market participants.

The OM&A component included in the WCA calculation will be incorporated in the cost allocation process as 15% of the allocated OM&A. If a distributor has a Board-approved working capital allowance different than 15%, then this percentage must be used for the WCA calculations (and noted in the Filing Summary).

10.5 PILs, Other Taxes, Cost of Debt, and Return on Equity

10.5.1 Background

These items are directly related to the value of net fixed assets.

10.5.2 Direction – Allocation of PILs, Other Taxes, Cost of Debt, and Return on Equity

A *pro rata* allocation of next fixed assets will be used to allocate PILs, Other Taxes, Cost of Debt, and Return on Equity.

10.6 Bad Debt Expense

10.6.1 Background

Bad debt expense consists of the amounts of uncollectible revenues. Many distributors monitor their bad debt write-offs at the rate classification level. The Accounting Procedures Handbook (Article 220) requires distributors to maintain records demonstrating uncollectible amounts by category, customer class, etc.

It is understood that the most common approach in other jurisdictions is that bad debt costs are directly allocated to specific customer rate classifications based on their respective contribution to historical write-offs. Staff recommended adoption of this viewpoint. The underlying cost allocation principle is that the differing bad debt experience of each classification is the relevant cost consideration when allocating bad debt expenses. This general approach is consistent with other class-based measurements (i.e. interclass load factors and peaking factors) used within the cost allocation model.

There is no stakeholder consensus on the issue; for example, some stakeholders argued it is fairer if customers share the responsibility for bad debts in proportion to their revenues. The Board considers the Staff recommended position to be more firmly defensible in terms of underlying cost causality and therefore should be followed in the filings as the general approach.

The role of “normalization” for bad debts also attracted stakeholder comments. Various stakeholders questioned whether application of the recommended position could lead to unusual results in some circumstances (for example, where there were few customers in a rate classification and one went bankrupt). The fairness and stability of a three year normalization period was also questioned. It should be recalled that extraordinary bad debts were excluded from 2006 revenue requirement if they occurred within the last three years, which is the basis of the bad debt expense to be allocated in the cost allocation filings. This tends to “normalize” the level of bad debt included in the approved revenue requirement. For cost allocation filing purposes, such extraordinary bad debt will also be excluded from the approved revenue requirement data used in the cost allocation filing model, and therefore it is less likely that an extraordinary bad debt will impact the reliability of the cost allocation results. If a concern regarding a result still remains after such normalization, it should be identified in the Filing Summary.

10.6.2 Direction – Allocation of Bad Debt Expense

Bad debt expense must be directly allocated to specific customer rate classifications based on their respective contribution to historical write-offs.

For historical test year filers, an average of bad debt data by rate classification for 2002, 2003 and 2004 must be used to allocate bad debt. For the future test year filers, the three year average of bad debt will include 2003, 2004 and 2005. In both cases, extraordinary bad debt will be excluded from the historical data. Any results a distributor considers unusual should be highlighted and discussed in its Filing Summary.

If historical bad debt is not available for any rate classifications that are being considered as new rate classifications in the filings (e.g. USL and LDG in Run 2 for most distributors), the bad debt allocated to its previous host classification should be allocated on a pro rata basis based on the revenues of each classification (i.e. the new rate classification and the host rate classification excluding the new rate classification).

In addition, a separate embedded distributor rate classification should not attract bad debt expense as the risk of non-payment for this rate classification is minimal.[17]

10.7 Late Payment Charges and Collection Expenses

10.7.1 Background

Late payment charges (Account #4225) include the amounts of discounts forfeited or additional charges imposed because of the failure of customers to pay their electricity bills on or before a specified date.

Collection expenses (Accounts #5320, #5325 and #5330) include all costs and recoveries of any charges associated with the collection of customer accounts.

A stakeholder suggested a common approach would be ideal for both costs, based on analysis of revenues and costs by class. It is considered premature to examine the issue further, as the extent of data on a historical rate classification basis is not known (further information is requested in the filing question below).

Therefore on practical grounds the allocator for the collection expenses will be the weighted number of bills.

[17] This will not apply to any embedded distributors that are modeled as part of a main rate classification in Run 1.

Stakeholders also commented that the incidence of late payment charges between rate classifications relates to the payment performance of the customers within the classification. It was therefore recommended that, similar to bad debt expense, the allocation of late payment charges should be based on the three year average of the revenues generated by these charges by rate classification.

10.7.2 Direction – Allocation of Late Payment Charges and Collection Expenses

Collection expenses will be allocated on the same basis as billing costs, namely by using weighted number of bills as the allocator.

Revenue from late payment charges will be allocated to classifications based on their respective contributions to historical payments.

10.7.3 Filing Question

To determine whether a similar cost allocation treatment of collection expenses and late payment charge revenues is feasible in the future, distributors should indicate whether the records are available to break out collection costs (Accounts #5320, #5325 and #5330) by rate classification.

10.8 Conservation and Demand Management ("CDM") Costs

10.8.1 Background

General Approach

The Technical Advisory Team believed that the general purpose of Conservation and Demand Management ("CDM") is to reduce energy consumption and peak demand. Based on this viewpoint, the suggestion arose during the consultations to allocate these costs in the cost allocation filings based on a combination of energy consumed and demand used (50/50).

On August 21, 2006 Board Staff issued a letter to stakeholders requesting comment on an alternative proposal for the allocation of CDM costs.
This proposal would allocate costs on the same basis as budgeted spending. The effect of the August 21st proposal would be to align the treatment of CDM/DSM costs between the Ontario electricity and gas distribution sectors.[18]

[18] In a recent generic gas DSM hearing (EB-2006-0021), it was agreed by all participants that costs should be allocated on the same basis as budgeted spending. This allocation would apply to both direct and indirect costs.

Several stakeholders commented on the August proposal. One stakeholder submitted that since the benefits of CDM are in avoided generation, the costs should be allocated based on the energy use of the class. Another stakeholder submitted that CDM costs should be allocated consistent with the approach used by the OPA for the recovery of such costs through the Global Adjustment Mechanism. A stakeholder indicated that the alternative proposal for CDM costs allocation is different from how the revenue requirement was initially allocated and will result in a disconnect between costs and revenues. One other stakeholder indicated that the 2006 EDR model allocated costs of CDM on the basis of distribution revenue, and in fewer than half of the requests for incremental funding for CDM within the 2006 EDR were costs allocated to specific customer classes. The same stakeholder submitted that given that the intent of CDM is largely to avoid new generation, the costs should be allocated to customer classifications on a proportion of 80/20 to energy/demand.

On the other hand, two stakeholders indicated they supported the August 21st proposal.

Given that no stakeholder consensus exists on a new position, the increased role anticipated to be played by the OPA in any event, and the view that some technical differences may exist between the electricity and gas distribution sectors, as a practical matter the Board concludes that the electricity sector status quo should be maintained for cost allocation purposes.

In this regard, note that the 2006 Electricity Distribution Rate Board Report RP 2004-0188 (the “2006 EDR Report”) concluded (see page 72): “direct CDM operating expenses will be allocated to the rate classes, sub-classes or groups specifically benefiting from the activities. The capital and indirect or overhead components of the revenue requirement will be allocated across all rate classes, sub-classes or groups based on the respective share of distribution revenue.”

The 2006 EDR Handbook is based on the above conclusion (see page 77).[19] The 2006 EDR model allocated capital and indirect operating expenses among the rate classifications based on their respective share of distribution revenue, which is the same allocator as was used for the largest part of distribution and administrative and general costs. Direct expenses were to be allocated directly to the benefiting customer classification.

For present filing purposes, Chapter 5 of this Report states: “Direct allocation must also be used where identifiable O&M activities can be directly allocated to one customer classification, and where supporting documentation in terms of sub-account records and explanations as to the related activities can be provided.”

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[19] A different CDM allocation methodology was mentioned elsewhere in the 2006 EDR Report (see page 114), but it was not followed in the 2006 EDR Handbook or 2006 EDR model.

Consistent with the methodology adopted in the rest of this Report, the Board directs that the CDM allocation methodology adopted below is to be applied to each rate “classification” (defined in Chapter 1 above as “generally referring to any separate distribution rate class or subclass”).

10.8.2 Direction – Allocation of Conservation and Demand Management Costs

For cost allocation purposes, CDM costs must be allocated as follows:

1. Direct CDM program operating expenses must be allocated to the participant customer classification.

2. Indirect operating costs and capital expenditures must be allocated in proportion to a broad composite of other distribution costs. In specific, indirect and capital CDM costs will be allocated to rate classifications in proportion to composite operating and maintenance costs.[20]

[20] This is the same allocation as for Administrative and General Costs net of insurance and community safety programs (see above Chapter 10).

Chapter 11

11. Cost Allocation and Unit Cost Calculations for Specialized Rate Classifications

Directions on cost allocation and unit cost calculations for the following specialized rate classifications are presented in this Chapter.

- Embedded distributor
- Density
- Seasonal
- Unmetered scattered loads (USL)
- Load Displacement Generation (LDG).

11.1 Embedded Distributor Classification

11.1.1 Background

Various approaches were used in the past to allocate costs to this rate classification. It is also understood that the rate structure has varied.
The present filings will introduce a common cost allocation methodology and customer unit cost calculation.[21] If any special situation arises for a host distributor serving several embedded distributors, this should be addressed and explained in the Filing Summary.

The methodology described below will be applied in Run 1 by all distributors with a current separate rate for embedded distributors, provided these rates are different than the approved rates of any other rate classification. The methodology must be applied in Run 2 by all distributors serving embedded distributors (in their 2006 EDR test year).The Board will later decide upon the merits of implementing such a new common rate classification for embedded distributors.

11.1.2 Direction – Cost Allocation and Unit Cost Methodology for Embedded Distributor Classification

The cost allocation methodology approved elsewhere in this Report must be applied when allocating costs to this rate classification. The same two-part customer unit cost calculation must be applied by all host distributors when modeling this rate classification.

[21] The general comments are also applicable when allocating costs to larger GS customer classifications or Large Users. A two-part distribution rate will be modeled for all customers.

For instance, the host distributor should consider if any assets can be directly assigned under the 100% use test. Host distributors should pay special attention that accounts have been properly broken into sub-accounts to reflect the various functions (the existence of bulk assets should be carefully reviewed). Reference should be made to Chapter 6 for details on how to break out the accounts into sub-accounts (also note the comments in Chapter 6 regarding the sub-functionalization method to be followed by Hydro One).

If a host distributor believes the results of the cost allocation study do not warrant creating (or maintaining) a separate rate classification for embedded distributor(s), this should be discussed further in its Filing Summary.

If the approved charge to an embedded distributor is represented as a separate rate classification in the 2006 rate order for the host distributor but the approved rates are the same rates as a main rate classification, then for Run 1 it should be assumed that the embedded distributor is part of that main rate classification. In such a case, the host distributor shall ensure the customer and load data of the main rate classification includes the data of the embedded distributor.

If a host distributor wishes to model an alternative to an embedded distributor classification, it can do so in its optional Run 3. The same underlying cost allocation methodology should generally be applied. Any use of an alternative methodology must be consistent with sound cost allocation practice, and it should be specifically noted and justified in the Filing Summary.

11.2 Density-Based Classifications

11.2.1 Background

It should be recognized that the average density for some currently-approved rate classifications varies significantly. In some cases, “urban” customers have been defined based on an average customer density higher than 60 customers per km of line, while the “suburban” (i.e. rural) classification customers typically have an average density of 12 customers per km of line or lower and are generally located in more rural areas.[22]

The density of a rate classification is considered to be a direct cost driver. For example, it is expected to take more lines and poles to service customers with a density of 12 customers per km than it does to service customers with a density of 60 customers per km. However, it may not be reasonable to assume that the density relationship is linear. In other words, it may not take five times the lines and poles to service a group of customers with a density of 12 customers per km compared to a group of customers with a density of 60 customers per km.

[22] One distributor has three density-based residential rate classifications.

The directions below provide instructions on how those few distributors with approved density-based rate classifications should undertake cost allocation for those customers. Some stakeholders questioned the effort to be required to support current density rates. The Board considers the methodology set out below to be a reasonable balance of cost causality and filing practicality.

Density-based rate classifications may be dropped in Run 3, but may not be added. Reasonable cost data must be provided in Run 1 and Run 2 for all currently-approved density classifications. The load data requirements must also be met. If a distributor plans to maintain density rates in the future, then more detailed analysis to support the different allocation of costs to the various density classifications should be undertaken and included with its cost allocation filing.

11.2.2 Direction – Cost Allocation Methodology for Density- Based Classifications

A distributor with density-based rate classifications is expected to be able to use the standard model in Run 1 and Run 2, but work must be undertaken to address some additional density-related inputs required.

The following common cost allocation methodology must be applied by all distributors with a density classification in their approved 2006 rates:

a) One categorization factor (i.e. appropriate generic minimum system result) must be used for the whole distributor.
b) The distributor must identify those costs that are influenced by density such as lines, poles and possibly line transformers. An explanation must be provided in its Filing Summary.
c) For meter reading costs, the standard cost allocation model already allows the distributor to allocate these cost to a rate classification based on density.
d) For the costs that have been identified in b), the distributor should weight the allocation factors used to allocate the cost to the various rate classifications by a density factor. The Filing Summary must include an explanation. A linear density-to-cost assumption is not acceptable without a supporting justification. More detailed analysis is required for the density weighting factors if the classification is to be maintained.
e) Each distributor must use its own current density threshold(s).

11.2.3 Filing Question

If a distributor intends to maintain its density-based rates, it must provide a rationale for the density threshold used for that rate classification.

11.3 Seasonal Rate Classification

11.3.1 Background

The standard cost allocation methodology will apply to any seasonal rate classification as no unique cost allocation issues were identified. There are few distributors with such separate rates currently in place.

Adding a new seasonal rate is outside the scope of this project and will not be allowed in Run 3. Dropping a seasonal rate classification may be modeled in Run 3; however, full supporting data must still be provided in Run 1 and Run 2.

A separate load data profile requirement has been established in the load data instructions for the seasonal classification and such data must be included in the filing.

Where density was one of the primary considerations in establishing the seasonal rate classification, the above cost allocation methodology regarding density rates should also be considered.

The consultations identified the potential for significant rate impacts in respect of the seasonal classifications if a shift were made to the use of 1 NCP for allocating demand-related costs.

11.3.2 Direction – Cost Allocation Methodology for Seasonal Rate Classification[23]

Run 1 and Run 2 of the model must apply the cost allocation and customer unit cost methodology approved in this Report.

Distributors wishing to apply 12 NCP must file a Run 3 and provide a supporting justification of this methodology based on the cost characteristics of its distribution system.

11.4 Unmetered Scattered Loads (“USL”)

In the past, there had been variability in the treatment of unmetered scattered loads across the Province. The present filings are intended to lead to a common cost allocation approach for these customers.

[23] The same cost allocation methodology will apply to the Farm Rate classification.

11.4.1 Cost Allocation Where Separate USL Rate Classification

11.4.1.1 Background

The Technical Advisory Team examined this topic in detail. Set out below is the common methodology approved for use by all distributors when modeling USL as a fully separate rate classification (e.g. Run 2).

The same approach must be applied in Run 1 by those few distributors whose 2006 approved USL charges function as a fully separate rate classification. This approach is not intended to be used in Run 1 by distributors whose 2006 USL rate were set using the special methodology arrived at during the 2006 EDR consultations.

11.4.1.2 Direction – Cost Allocation Methodology where Separate USL Rate Classification

The cost allocation methodology approved in this Report for all rate classifications must also be applied to this rate classification, subject to any special rules specifically provided for below.

Customer-related Costs

Billing-related costs will be allocated based on the number of invoices sent to USL customers. However, distributors invoice USL customers differently. The different approaches include:

a) A separate account and invoice for each connection.
b) A separate account for each connection and a single summary bill produced by an off-line process.
c) A single bill, aggregated within the billing system.

The billing costs are to be allocated using the number of bills issued by a distributor for USL customers based on the invoicing approach used by the distributor. To the extent that some distributors may have incurred system costs to enable the consolidation of the bill for USL customers, such costs must be identified and allocated to this rate classification as it has benefited from the service.

USL customers must not be allocated costs related to meter reading expenses (Account 5310) since they are unmetered.

If known and identifiable, expenses such as tracking additions and deletions of connections or revising estimated consumption should be directly allocated.

Distribution and General Plant

Unmetered Scattered Load customers will bear the full allocated costs of distribution facilities (and associated depreciation), with the exclusion of Load Management Controls – Customer Premises (Account 1970) and Meters (Account 1860).

A distributor that installed test meters on USL in its test year as part of an ongoing verification program must allocate the corresponding meter costs to USL.

Operation and Maintenance Expenses

Operation and maintenance expenses allocated to the USL classification will exclude the following accounts: customer premises (Accounts 5070, 5075), maintenance of meters (Account 5175), and meter expenses (Account 5065). Distributors that have installed verification meters on USL must allocate the corresponding meter related costs to USL.

11.4.1.3 Filing Questions

The following information is to be provided.

1. As a distributor, is there summary billing for USL customers?

2. Does the distributor do summary billing for customer classifications other than USL? If yes, provide number of customers by classification and number of customer “sub-accounts” that the summary bills include.

3. Provide the estimated cost of making summary bills available and the overall savings (i.e. savings on extra costs) realized by the distributor.

11.4.2 Cost Allocation Where USL Part of GS<50 kW with Metering Credit

11.4.2.1 Background

The approach below is expected to apply to most distributors in Run 1, including all those whose 2006 USL charges were effectively based on the special rate calculation reached during the 2006 EDR process.[24]

For cost allocation purposes, it is considered more useful to model USL rates under these circumstances as follows: demand costs will be treated as related

[24] This approach will not apply to those few distributors whose current USL charges function as a fully separate rate classification (for example, where a separate USL rate classification is based on a prior cost allocation study).

to the GS<50 kW rate classification, while cost-justified adjustments will be made to reflect documented differing customer costs.

For purpose of the cost allocation filings, the process below will be used to determine an adjustment to standard rates reflecting the estimated reduction to rates that would occur when a customer is unmetered. The model will calculate a USL unit cost for a potential “metering credit”.

If a metering credit is to be implemented in the future for USL customers, then the amount of such a credit would need to be collected from other customers in order for the distributor to still collect its total revenue requirement. Details on how to co-ordinate the collection of the revenue requirement with the provision of an appropriate level of a new USL metering credit should be addressed if implementation of this approach proceeds.

11.4.2.2 Direction – Unit Cost for USL Metering Credit

The following methodology must be used to determine the metering credit for USL customers in Run 1. The first step is to identify the following items in the cost allocation model.

a) Depreciation on Account 1860 – Meter Assets
b) Meter expense – Account 5065
c) Customer Premises – Account 5070 and 5075
d) Meter Maintenance – Account 5175
e) Meter Reading – Account 5310
f) General plant allocated to meters
g) Administration and general expenses allocated to meters
h) PILs and return on equity and debt that would be allocated to the net fixed assets associated with the assets listed in a) and f).

In order to determine the unit cost to support the metering credit, the total costs associated with the above must be determined for the General Service < 50 kW classification and divided by the number of customers in the GS<50 kW rate classification that have a meter.

Some stakeholders suggested that an adjustment for billing costs should also be considered. However this step will not be included in the filing requirements as the billing costs allocated to the standard classification will reflect the billing characteristics of USL.

11.4.3 Unit Costs Where USL a Separate Classification and Future Rate Design Options

11.4.3.1 Background

Run 2 of the filings will provide the Board with information on costs for USL as a separate rate classification. Once costs have been allocated to this potential rate classification, the question remains whether it is preferable to determine the unit costs on a per customer or per connection basis. Some costs are likely driven on a per connection basis, while others on a per customer basis.

The present filings will produce standard customer unit cost outputs for the Run 2 separate USL rate classification.

11.4.3.2 Direction – Modeling Unit Costs Where USL a Separate Rate Classification

The cost allocation filing model will calculate a standard two-part unit cost output for USL.

1. Customer-Related Unit Cost – Number of Connections

   The customer-related costs allocated to the USL classification will be divided by the number of connections to determine the customer-related unit cost.

2. Demand-Related Unit Cost – kWh

   The demand-related cost allocated to the USL classification will be divided by the kWh associated with the USL classification to determine the demand-related unit cost.

   One stakeholder suggested that demand-related costs should be divided by the kW associated with the USL classification to determine the demand-related unit cost. It was commented this is not readily available for distributors, but others suggested that one could be constructed from the deemed load profile for the various USL applications. Since in Run 1 USL is part of the GS<50kW classification for which kWh is the basis of the unit cost, the same basis will be used in the demand-related unit cost for USL customers.

11.5 Load Displacement Generation (“LDG”) Rate Classification

11.5.1 Introduction

At present, a number of distributors have approved interim standby rates. In some cases, there is an additional approved administrative charge.

The Board reviewed standby charges in the generic decision RP-2005-0020/EB-2005-0529 (March 21st, 2006). The Board commented:

> “It is also evident that the new standby rates proposed in this proceeding by a number of distributors do not have a proper cost foundation due to lack of available data. The Board agrees that proper costs and benefits allocation should be employed in setting these rates. ….
>
> The Board also believes that a standard methodology across all utilities is preferable, but notes that a standard methodology does not necessarily mean identical rates.
>
> The starting point for the development of the standard methodology would be the proper allocation of costs to those that cause the cost, as well as quantification of the benefits.”

By way of illustration, a distributor may be asked to provide standby distribution service to customers who have their own load displacement generation. Typically, these load displacement generators produce most of their own electricity and use the distributor’s wires and obtain commodity supply to fill in the difference between their total electric demands and the energy produced with the load displacement generator. Standby distribution service is typically called upon during the load displacement generator’s routine maintenance of the turbine/generator and during force majeure situations.

The cost allocation filings will develop a common methodology to model the readily quantifiable distribution costs associated with providing distribution services to customers with load displacement generation facilities, both as part of a standard rate classification and as a separate rate classification. Final evaluation of the merits of these two approaches will occur later.

This section of the Report will set out a common cost allocation approach for distribution costs associated with the LDG rate classification and with the resulting unit costs. The intent is to accurately and reliably allocate costs to LDG customers; how the costs allocated to the LDG classification should best be recovered in future rate design (which could involve the use of charges for standby distribution service) will be addressed in separate consultations.

Identification and quantification of benefits and costs arising from load displacement facilities on the other parts of overall electricity sector, such as the transmission system, will not be addressed in these filings. Note that some benefits from load displacement facilities may not accrue to the distributor.

11.5.2 Total Load for Load Displacement Generation Classification

11.5.2.1 Background

The LDG rate classification to be modeled refers to charges imposed by a distributor for distribution services provided to a customer with load displacement generation behind the customer's meter. The load displacement generation provides generation for self-service with no significant generation above the customer's load.

The total costs to be allocated to the LDG classification will consist of costs associated with providing distribution service to the base load that is the same as a standard distribution customer, along with the distribution costs required to support the incremental load when the load displacement generator is not operating.

The costs associated with incremental load can be viewed as the cost of providing the standby distribution service. These costs can be determined from comparing the various runs of the model. These results can be considered later when discussing standby rates and other rate design options.

The load data requirements when modeling LDG customers as a separate rate classification are addressed in Chapter 3. Some concerns have been expressed about the availability and reliability of load data for these customers. This will be considered when evaluating the filing results.

11.5.2.2 Direction - Calculation of total load for LDG classification

In the cost allocation filings, the load associated with a LDG customer will be the full measured load of the customer, which includes the load when the load displacement generator is running and the incremental load with the generator not running (i.e. standby distribution service). This will apply to Runs 1 and 2.

The cost allocation methodology developed will be consistent with the above and thus determine the costs to be allocated to the full load of a LDG customer and not just the load displacement component.[25]

Some stakeholders considered that the measured load taken from the distribution system by the LDG customer did not appropriately capture the distribution requirements that the distributor must have available at all times to

[25] Therefore no run of the model will directly calculate a "standby" charge to compare to the current interim standby charges. It is anticipated that such charges could be calculated later based on the results of the cost allocation filings.

serve the LDG customer's potential total requirement. Therefore in an optional Run 3, the actual or measured load of the LDG customer taken from the distribution system should be increased to reflect the maximum potential requirement of the LDG customer; in other words, for each hour the actual, or an estimate of, the load supplied by the generator should be added to the measured load of the LDG customer supplied by the distributor. If the LDG customer has a contract with the distributor for firm back up service that specifies a maximum demand or contract demand for the back-up service, then the greater of the contract maximum demand or the adjusted load should be used.

11.5.3 Cost Allocation Methodology Where Existing Load Displacement Customers are part of a Main Rate Classification (Run 1)

11.5.3.1 Background

From a distribution system perspective, LDG service includes a commitment by the distributor to have sufficient conductor and transformation capacity available to meet the load displacement customer's total load requirements even when the load displacement generator is out of service.

Under this view, a useful initial step in determining distribution rates for LDG customers would be use of the new cost-based rate information of other full service customers of similar size. This information will be readily available from filing the model and will be used in Step 1 below.

LDG service could lead to other savings or costs that should be taken into account by way of a separate charge or credit before finalizing distribution rates for LDG customers. Some stakeholders cautioned that it would be difficult to quantify many of these items and that full quantification of all potential benefits requires specialized studies that are unlikely to take place through these filings. However, to make progress on the consideration of these issues, the Board expects distributors that have customers with load displacement generation will use their best efforts to respond to the questions below about these benefits and costs.

The methodology below should be followed in Run 1 for those distributors with current standby distribution rates, where the substance suggests a separate rate classification does not underlie the approved rate (see Chapter 2 for details). It should also be used in Run 2 by any distributors with known load displacement customers but lacking minimally acceptable load data to calculate demand costs for a separate LDG rate classification (an explanation should be provided in the filing in such a case).

Stakeholders have observed that the general objective of the filing is to allocate the approved 2006 revenue requirement. Therefore the distribution costs underlying approved 2006 rates should be the basis of the financial data used to model the LDG classification in Run 1 and Run 2. If distributors have other relevant information available on costs or benefits associated with LDG customers, that should be included in a Run 3.

It has been suggested by some stakeholders that Run 1, which assumes the customers with LDG are in a main rate classification, will provide more reliable results for future consideration by the Board. Some stakeholders are concerned that in Run 2, the number of customers with LDG assigned to the new rate classification could be small. Any irregularity with one or more of these customers usage in the test year could lead to results which are not stable and predictive. Any such concern by a distributor should be noted in its Filing Summary.

If a LDG charge or credit is to be adopted in the future for LDG customers, then the implementation of new rates should recognize that once a credit or charge is given it to one group of customers an offsetting amount needs to be collected from or credited to another group of customers in order to maintain the same total revenue requirement for the distributor. Details on how to co-ordinate the collection of the revenue requirement with the provision of an appropriate level of a new LDG credit or charge should be addressed if implementation of this approach proceeds.

11.5.3.2 Methodology for Calculating Unit Costs for LDG Service as Part of a Main Rate Classification

Filing Step 1) Initial Customer Unit Costs to be Calculated by Model

The cost allocation model will calculate a range of customer unit costs ($/customer/month) and a demand unit cost ($/kW/month) for all rate classifications. These same unit costs should be used as the first step in calculating new distribution rates for LDG customers when they are provided distribution service under the umbrella of a main rate classification.

For instance, assume that the lower and upper range of customer unit costs for a distributor’s General Service > 50 kW classification are $200/month and $250/month respectively and the demand unit cost is $5/kW/month. For a customer with a load displacement generator whose load requirements from the distribution system would place it on the General Service > 50 kW rate, the filing model will generate for such a LDG customer initial unit costs of $200/month to $250/month range for the customer component and $5/kW/month for the demand component.

Filing Step 2) Identify Items for Inclusion in Additional LDG Credit or Charge Unit Cost Calculation

Further adjustments to the above initial unit costs must be considered by a distributor. The intent is to capture any unique distribution system net costs (i.e. gross costs minus savings included in the 2006 EDR data) applicable to LDG customers beyond other customers grouped with them in the relevant Run 1 main rate classification.

Specifically, the following potential adjustments must be considered and identified as part of the filing.

i) Within the 2006 approved rates, some distributors already include a special administration charge for standby customers to cover off the extra ongoing costs. The costs associated with this administration charge should be directly allocated to the classification that has the LDG customers. Please refer to Chapter 5 for the direct allocation methodology. In addition, the revenue from any special administration charges will be recognized in the revenue for this rate classification.

ii) Adjustments may be necessary to the allocation factors where special metering capital costs are included. Please refer to Chapter 9 in regard to the treatment of metering costs.

iii) Capital contributions may have been collected from LDG customers and this should be reflected in the allocation of capital contribution.

iv) If a distributor can identify in its 2006 EDR data any other additional net costs for servicing LDG customers, these costs should be directly allocated to the classification that has LDG service customers. In this regard, a distributor must review the list provided in Appendix 11.1 of additional potential distribution system savings and costs arising from the installation of load displacement facilities and determine whether any such items have been recognized on a net cost basis (i.e. gross cost minus savings) in the trial balance that supports the 2006 approved rates.[26]

Filing Step 3 - Calculation of LDG-specific Unit Costs

The filing model cannot undertake the LDG credit or charge calculation itself. However, filing instructions on how to undertake the calculation will be

[26] If little additional data is provided under iv), then the amount of the resulting LDG charge or credit may not lead to a significant difference from the rate for the main rate classification applicable to the LDG customer.

provided.[27] This calculation of the underlying LDG-specific unit costs should be undertaken as part of the present filings.

The resulting unit costs could be used to help design a LDG credit or charge if LDG customers are to be treated as part of a main rate classification**.**

Future Rate Design Steps

The LDG-specific unit costs calculate above will be one of the items of information to be available and considered when designing and implementing new LDG rates.

The unit costs calculated here should not be interpreted as representing a proxy for new standby distribution rates, as the LDG unit cost represents the costs of providing the standard distribution service for the base load as well as the standby distribution service. It is planned that the merits of all the various options for designing rates for LDG customers will be examined in the forthcoming Distribution Rate Design Review (assisted by the information collected in the cost allocation filings).

11.5.4 Threshold for Customers in Separate Load Displacement Generation Rate Classification (Run 2)

11.5.4.1 Background

There have been discussions with stakeholders as to what might be the appropriate threshold at which a customer with load displacement facilities would be defined as a LDG customer for capturing in Run 2 of the cost allocation modeling.

As a practical matter, some stakeholders suggested that such a threshold should be consistent with the net-metering threshold of 500 kW.

11.5.4.2 Direction – LDG Rate Classification Threshold

For the purpose of modeling the costs to be allocated to the separate LDG rate classification in Run 2, a customer will not be considered to be part of that separate rate classification unless its standby distribution service requirements are greater than 500 kW. If the standby distribution service is lower than that

[27] These are the steps: The identified costs and revenues associated only with LDG customers should be separated into customer and demand related costs and revenues. The total customer related items should be divided by the number of LDG customers in Run 2. The total demand related items should be divided by the total kWs for LDG customers in Run 2.

threshold, the customer should be treated as a standard customer in the classification of service it receives.

For the purpose of applying the 500 kW standby threshold, the standby distribution requirement should be based on the rated capacity of the load displacement generator unless the distributor has a formal contract with the customer specifying an alternate value. If a distributor is aware of a load displacement customer and does not have information on the rated capacity of that load displacement generator, it should contact the customer to collect the necessary information for the distributor's cost allocation filing to the Board. If no detailed information is obtained, an explanation as to why should be provided in the distributor's Filing Summary, and the distributor should estimate the distribution standby requirement from the difference between the peak month when the load displacement generator is not running and the average 12 month load of the LDG customer. The Filing Summary should note any concerns about the reliability of such an estimate.

11.5.5 Cost Allocation Methodology Where LDG Rates are a Separate Rate Classification (Run 2 and Run 3)

11.5.5.1 Background

For Run 2 of the model, all distributors serving LDG customers with standby distribution service requirements above the 500 kW threshold should group these customers into a separate LDG rate classification and provide full supporting data.

Use of this methodology assumes that the distributor was able to gather some relevant load data for modeling the separate rate classification approach. The load data requirements for LDG customers as a separate rate classification are set out in Chapter 3. Some distributors have cautioned suitable load data may not be available. The first LDG cost allocation methodology should be used in both model runs in such cases, and a detailed explanation provided in the Filing Summary.

The methodology below will also be applied in Run 1 for those distributors where the underlying substance of their approved 2006 standby distribution rates suggests a separate LDG rate classification is appropriate for Run 1 cost allocation modeling purposes. An explanation should be provided in the Filing Summary in such a case.

11.5.5.2 Direction – Cost Allocation Methodology Where LDG Rates Modeled as Separate Rate Classification

The same cost allocation methodology approved for use with other rate classifications must be applied to this classification (for example, the distinction between bulk, primary and secondary distribution costs will likely be applicable to LDG customers).

As discussed in Chapter 3, the default load data method must be used when modeling a separate LDG rate classification in Run 2. Distributors will have the option to use the load data alternative discussed in Chapter 3 for Run 3, but must fully document any estimates used and address the diversity issue.

In Run 2, since the LDG customers form a separate classification, a separate calculation of a charge or credit is not necessary since the net costs are attributed to this classification. Nevertheless, the potential net costs described above in filing Step 2 should be reviewed as they may also apply to the separate LDG rate classification to be modeled and filed. As part of this, distributors must review the list of potential additional costs or savings set out in Appendix 11.1.

In Run 2 (and Run 3), the filing model will also generate a two part distribution charge for all rate classifications, including the separate LDG rate classification.

11.5.5.3 Direction – Number of New LDG Rate Classifications Run 2

To better reflect cost causality, it was originally suggested that separate LDG rate classifications will be required, where relevant, for GS>50 kW, Intermediate and Large User customers. Questions have been raised about the reliability of the underlying load data. From a load data reliability perspective, it would be better to have more customers in the new classification (i.e., have only one LDG classification). Therefore the filing model will have a single LDG classification in Run 2.

Distributors should indicate in their Filing Summary the number of customers in LDG rate classification by the rate classifications to which the customers were previously assigned before they were placed in a separate classification.

Some distributors have commented they may prefer to model multiple LDG rates in an optional Run 3. If each such rate is to be modeled as a fully separate rate classification with its own load data requirement, then the reliability of the load data used should be discussed in the distributor's Filing Summary.

11.5.5.4 Potential Further Adjustments in Run 3

If any other significant additional distribution system benefits or costs can be identified and quantified at this time by a distributor following its review of Appendix 11.1 (i.e. outside of those items included in the trial balance figures which supported approved 2006 EDR rates and which should be taken Into account in Run 1 and Run 2), then such information should be included in a Run 3 of the model to be submitted along with an explanation in the distributor's Filing Summary.

11.5.5.5 Filing Questions

i) If a distributor has an approved administrative charge in respect of standby rates, then it should explain the basis and components of this charge.

ii) If the distributor incurs other extraordinary costs to provide service to a load displacement generator, how will these extraordinary costs be recovered? (For example: by way of a capital contribution, by a rate rider for the specific customer, or rolled into rates for all customers in the classification.)

iii) Where a distributor with a currently approved standby rate (including interim standby rate) cannot presently quantify any additional benefits and/or costs after reviewing Appendix 11.1, then the distributor must outline the elements that could be included in any future study designed to document the distribution benefits and costs and benefits from load displacement facilities, or indicate any other means by which it could estimate such distribution benefits and costs.

11.5.6 Benefits of Diversity

11.5.6.1 Background

This issue has received considerable attention in other jurisdictions and therefore it is important to explicitly address it. For example, it is understood FERC rules provide standby service rates "shall not be based upon the assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both".

The Technical Advisory Team cautioned it should not be assumed that there will be diversity benefits in all circumstances. The benefits of diversity are expected to grow as the number of load displacement facilities increases. The sharing of the benefits of diversity will likely differ under each of the two cost allocation methods approved for LDG service customers.

11.5.6.2 Direction – Where LDG Customers Not Separate Classification

In most cases, Run 1 will have the customers with load displacement in a standard rate classification and the diversity of the total standard rate classification will be reflected in the unit costs. This means the combined diversity benefits associated with customers using LDG service as well as all other customers in the classification will be reflected in the LDG Run 1 initial unit costs. (As discussed above, customer costs unique to LDG customers should also be identified for calculating an additional LDG credit or charge.)

11.5.6.3 Direction – Where LDG Customers Separate Classification

In Run 2, the customers with load displacement will be assigned to a separate rate classification and only the diversity benefits associated with the customers using LDG service will be reflected in the classification's unit costs.

11.5.7 Future LDG Customer Rate Design

Issues surrounding the design and implementation of new rates for load displacement customers (including the merits and design of charges for standby distribution service) will be further addressed in the pending Distribution Rate Design Review. Interested stakeholders are invited to participate in those consultations. It is anticipated that future discussions will build upon the costs allocated to load displacement customers in the various runs of the cost allocation filing model.

The present process is intended to gather a broad range of potentially useful information. The appropriate weight to be given the LDG-related information directly generated under Runs 1, 2 and 3 of the filings, or available upon comparison and analysis of the filing runs, will be determined later. As part of that, the reliability of the separate LDG load data collected for Run 2 of the filing will likely need to be assessed (to allow a proper comparison to the reliability of the results under Run 1). In addition, the merits of the Run 2 versus Run 3 approach to load data determination was not finalized in these consultations and therefore will likely require further Board attention before rates are updated for LDG customers.

11.5.8 Merchant Generation

11.5.8.1 Background

A merchant generator is defined to be a generator that provides a significant amount of its generation into the distribution system and also provides the generation required to support its own electricity needs. When the merchant generator is shut down, the distribution system will most likely need to support the load requirement of the merchant generation station and to provide whatever power is required to start the merchant generator. This should be considered when allocating costs to this rate classification and discussed in the distributor's Filing Summary. This Report will not further address the issues surrounding distribution rates for merchant generation.

11.5.8.2 Direction - Optional Modeling

In Run 3, an interested distributor has the option of modeling appropriate unit costs for merchant generation in place in the 2006 EDR test year. This will be required for a specific distributor under a prior Board decision.

In such a case, the distributor's Filing Summary should discuss the general approach used (e.g. whether a fully separate rate classification was established), document supporting accounting and load data used, and explicitly identify and justify if any cost allocation method was utilized which differs from what is approved in the present Report.

11.5.9 Hybrid Facilities

There is also the situation where a generator is providing load displacement generation but also has significant generation above the customer's load.
In this case the generator is performing a "hybrid" role of load displacement and merchant generation. This Report will not further address the issues surrounding distribution rates for such hybrid facilities. However, appropriate unit costs for these facilities in place in the 2006 test year could be modeled by an interested distributor in the optional Run 3 of the model. In such cases, the distributor's Filing Summary should discuss the general approach used, document supporting accounting and load data used, and explicitly identify and justify if any cost allocation method was utilized which differs from what is approved in the present Report.

11.6 Other Specialized Rate Classifications

Various utility-specific rate classifications exist (such as a small commercial rate or a water sewage facility rate).The affected distributor should apply the approved cost allocation methodology to the extent possible, including load data requirements (see Appendix 3.1). If any changes or additions are made to the cost allocation methodology applied to these specialized rates by the distributor, the alternative method followed should be consistent with sound cost allocation and should be explained and justified in the distributor's Filing Summary (and supporting information provided in the filing).

If a distributor is considering eliminating a utility-specific rate classification in the future, an explanation should be included in its Filing Summary and the effect should be modeled in Run 3.

Chapter 12

12. Unit Cost Outputs

The cost allocation filings will gather customer unit cost information to assist with future discussions on the following rate design areas:

a) Review of the range of monthly customer service charges.
b) Review of alternatives to the current transformer ownership allowance.

Directions on how the filing model will provide unit cost information in regard to the above areas are presented in this Chapter. Filing questions regarding Wholesale Market Participants are also set out.

12.1 Monthly Service Charges

12.1.1 Introduction

The OEB's letter of June 24, 2005 advised that "the cost allocation filings will also contain updated information that is helpful to assess the cost basis of current monthly service charges". The filings will achieve this by calculating reasonable cost-based lower and upper end customer unit costs per month. The calculation will be applied to all currently approved rate classifications (Run 1), as well as the select new rate classifications to be modeled in Run 2 (or Run 3).

The present project focused on identifying distribution system cost drivers, but a variety of rate design factors, including non-cost considerations, are commonly taken into account when setting the actual rates. The cost allocation review will assume continuation of a two-part distribution rate structure, but the underlying data collected will be of relevance to stakeholders interested in a one-part distribution rate structure.

12.1.2 Lower End Customer Unit Cost Calculation

12.1.2.1 Background

Three versions of the Basic Customer Method were reviewed for use to calculate the lower end of the customer unit costs.

Option 1: Avoided Costs

With a strict “avoided cost” approach, only meter related costs, billing and collection costs would be included. This approach has the advantage of focusing on the immediate costs of an additional customer. But no administration and general overhead would be applied and this can be considered a shortcoming of the approach.

A stakeholder proposed that in the interests of creating stronger conservation price signals, the lower floor for monthly customer service charges should be set by the avoided cost approach. The Board wishes to reinforce that the purpose of the present filings is to produce a broad range of information for subsequent rate design decision-making. This option will therefore be modeled in the filings.

Option 2: Directly Related Customer Costs

In this approach, additional costs viewed as directly related to the customer would be included, namely operations performed at the customers’ premises. An example would be a disconnect and a reconnect for safety reasons. Revenue from related operations such as Service Transaction Request revenue and Late Payment charges would be credited back to the cost centres. The calculation also includes an allocation of administration and general overhead. It is understood this approach towards the basic customer cost calculation is the most commonly used elsewhere. This approach will also be incorporated in the filing model.

Option 3: Basic Connection

In this option, the basic customer cost would include the basic connection costs as defined in the Distribution System Code in addition to the customer related costs identified in Option 2. Setting the floor at the higher level that would result from Option 3 would establish a very narrow range of reasonableness for customer unit costs and so will not be modeled in the filings.

12.1.2.2 Direction – Calculation of Lower and Upper End Customer Unit Costs in Filings

Both Option 1 (avoided costs) and Option 2 (directly related customer costs) should be calculated in the filings to provide a broad range of information on a reasonable lower end unit cost per customer per month for each rate classification modeled in Runs 1, 2 and 3. Appendix 12.1 lists the specific costs to be included in each calculation. The filing model will incorporate the calculations.

The reasonable upper end unit cost per customer per month will be determined by the customer-related costs allocated using the generic stratified minimum system results and adjusted for PLCC as outlined in Chapter 7. The filing model will produce such outputs for each rate classification.

12.1.2.3 Smart Meter Adder

The above lower and upper end customer unit costs must both be adjusted to include the smart meter adder, to be consistent with the monthly fixed charges approved in the 2006 rate orders. A distributor will enter the smart meter adder into the cost allocation model by rate classification. In most cases, the distributor will find the adder in the formula bar of column T, Sheet 8-5, of the approved 2006 EDR model.

12.2 Substation and Secondary Transformation Ownership Unit Costs

12.2.1 Background

Currently, a distributor provides a transformer allowance to those customers that own their transformation facilities. With a few exceptions, the present level of transformer ownership allowance is $0.60 per kW. The amount of the allowance has not been reviewed on a generic basis in recent years. The filings will use a new common methodology, and distributors will enter their own local cost data. To refine the calculation, a two part transformer allowance will be modeled (substation and secondary transformation).

It is understood that the present allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since it is assumed that the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides the step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

As a result of separating the distribution system into bulk, primary and secondary functions, as outlined in Chapter 6, it has become apparent that a customer may own other primary and secondary assets and could be paying for these additional facilities in their standard rates. For example, a General Service > 50 kW customer who is taking power from the primary assets would be paying for distributor-owned secondary transformation, poles and conductors in its standard rates but would not be using these facilities. The same would be the case where a customer is taking power from the bulk assets and their standard rates include primary and secondary costs.

A stakeholder has suggested that an additional cost pool should be added to separately track bulk conductors/poles, which would be applicable in those circumstances where bulk facilities are not used to service all customers in the distributor's service area. Note a customer that owned its own bulk asset would not be connected to the distribution system. The present consultations have proceeded on the basis that the updated allowance to be modeled is intended to be an allowance for ownership (as is presently the case) and not for non-usage (as is effectively assumed in the cost causality rationale that would support the suggestion). Accordingly the Board believes there is not a sufficient case at this time for gathering the additional information requested.

It was suggested that customers who own their transformation facilities have historically received a credit for this ownership and this should continue. However, to provide an additional credit beyond transformation ownership allowance would not be consistent with being part of standard rate classification that shares the costs and benefits of being in the classification.

The present cost allocation process is intended to collect the information relevant to this issue. Data will be collected on four underlying cost pools. However, to maintain a more straight-forward filing, the filing model will calculate new unit costs for substation and secondary transformation only.

The information gathered on the two other cost pools (primary and secondary conductors and poles) will be available in case of any future discussions on the pros and cons of further refinements. It was suggested rate design philosophy would need to be further addressed before this extra information could be utilized.

During consultations, questions were asked by distributors about the likely amount of a new transformation allowance compared to the volumetric distribution charge. Concern was expressed about the potential for anomalous appearing results. Any specific concerns that do materialize can be highlighted as part of the Filing Summary filed by the distributor.

12.2.2 Direction – Updated Unit Cost and Cost Pools Information

For the purpose of determining updated unit costs, the starting point will be the standard unit costs that include all costs associated with transformation. The new transformation ownership allowance calculation will adjust, based on cost causality considerations, the standard unit costs for those customers that own their own assets.

The filing model will calculate new unit costs for both substation transformation and secondary transformation.

To provide full information, the filing model will collect data on the following four cost pools by rate classification.

a) Substation transformation
b) Secondary transformation
c) Primary conductors/poles
d) Secondary conductors/poles.

12.2.2.1 Direction – Substation Transformation Ownership Allowance Unit Cost Output

The following costs will be included in the new substation transformation ownership allowance unit cost calculation produced by the filing model.

a) Depreciation on sub-accounts 1820 -2 Distribution Station Equipment - Normally Primary below 50 kV; 1825 -2 Storage Battery Equipment; 1805 -2 Land Station<50 kV; 1806 -2 Land Rights Station < 50 kV; 1808-2 Building and Fixtures <50 kV; and 1810-2 Leasehold Improvement < 50 kV.
b) Stations Buildings and Fixtures Expense – Account 5012.
c) Operation expense on distribution stations – Accounts 5016 and 5017.
d) Maintenance expense on distribution stations – Accounts 5114.
e) A pro rata share of Accounts 5005, 5010, 5085 and 5105 based on the distribution assets identified in a).
f) General Plant allocated to distribution station assets.
g) Administration and General Expenses allocated to distribution station assets.
h) PILs and return on equity and debt that would be allocated to the net fixed assets associated with the assets listed in a) and f).

In order to determine the unit cost underlying the substation transformation ownership allowance to be modeled, the total costs associated with the above will be determined by rate classification and divided by the appropriate kWs, kVa and/or kWhs (if applicable) for those customers that use distributor-owned substation transformation assets. The unit cost underlying the substation transformation ownership allowance will be calculated for all rate classifications that have substation transformation costs allocated to the rate classification.

12.2.2.2 Direction – Secondary Transformation Ownership Allowance Unit Cost Output

The following costs will be included in the new secondary transformation ownership allowance unit cost calculation produced by the filing model.

a) Depreciation on account 1850 - Line Transformers.
b) Operation expense on overhead distribution transformers – Account 5035.
c) Operation expense on underground distribution transformers – Account 5055.
d) Maintenance expense on line transformers - Account 5160.
e) A pro rata share of Accounts 5005, 5010, 5085 and 5105 based on the distribution assets identified in a).
f) General plant allocated to distribution transformer assets.
g) Administration and general expenses allocated to distribution transformer assets.
h) PILs and return on equity and debt that would be allocated to the net fixed assets associated with the assets listed in a) and f).

In order to determine the unit cost underlying the secondary transformation ownership allowance to be modeled, the total costs associated with the above will be determined by rate classification and divided by the appropriate kWs, kVa and/or kWhs (if applicable) for those customers that use distributor-owned secondary transformation assets. The unit cost underlying the secondary transformation ownership allowance will be calculated for all rate classifications that have secondary transformation costs allocated to the rate classification including any classification(s) that bill volumetric distribution charges on a kWh basis such as the Residential classification.

12.2.2.3 Direction - Primary and Secondary Conductors and Poles Cost Pools Calculation

Appendix 12.2 sets out the additional information on primary and secondary conductors and poles cost pools to be gathered by the filing model for potential future reference. Further rate classification and rate design policy discussions would be required before it can be determined how the information could be appropriately used.

12.3 Filing Questions - Customers that are Wholesale Market Participants

These questions relate to customers who are connected to the distribution system but have chosen to be wholesale market participants (and who are not a generator).The information is expected to be of assistance if a credit for these customers is discussed anytime in the future**.**

a) Provide the number of customers and delivery points, annual kWhs, and kWs (if applicable) by rate classification for those customers that are wholesale market participants. If a) is applicable, please answer b) and c).

b) Are there any other additional costs of providing service to customers who are wholesale market participants, over and above the costs associated with a comparable customer who is not a wholesale market participant? If yes, identify the additional cost items and estimate the incremental cost amounts.

c) Are there any costs that are avoided in providing service to customers who are wholesale market participants? If yes, identify the avoided cost items and estimate their value.

Appendices

Appendix 1.1

Parties submitting comments on the Board Staff's June 28, 2006 Proposal

- Association of Major Power Consumers of Ontario
- Association of Power Producers of Ontario
- Canadian Cable Telecommunications Association
- ECMI Coalition
- Enersource Hydro Mississauga Inc.:
  (on behalf of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, Toronto Hydro-Electric System Limited and Veridian Connections Inc.)
- Enwin Powerlines
- Green Energy Coalition
- Hydro One Networks Inc. and Hydro One Remotes
- London Property Management Association
- Schools Energy Coalition
- Veridian Connections Inc.
- Vulnerable Energy Consumer's Coalition
- Waterloo North Hydro Inc.

Parties submitting comments on the Staff's August 21, 2006 Proposal letter

- Association of Power Producers of Ontario
- ECMI Coalition
- Federation of Ontario Cottagers Associations
- Green Energy Coalition
- Hydro One Networks Inc. and Hydro One Remotes
- Hydro Ottawa Limited:
  (on behalf of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.)
- Vulnerable Energy Consumer's Coalition

Appendix 1.2

Technical Advisory Team Members: Phases 1, 2 or 3	**Name**
Alliance of LDCs	Jim Richardson
Alliance of LDCs – Newmarket	Dave Weir
AMPCO	Ken Snelson
AMPCO	Wayne Clark
Bob Mason and Associates	Bob Mason
Canadian Cable Telecommunications Association	Paula Zarnett
Canadian Niagara Power Inc.	Douglas Bradbury
Chatham – Kent Hydro Inc.	Jim Hogan
ECMI Coalition	Roger White
Enersource Hydro Mississauga Inc.	Ralph Amar
Enersource Hydro Mississauga Inc.	Kathi Litt
Horizon Utilities Corporation	Dan Gapic
Hydro One Brampton Networks Inc.	Scott Miller
Hydro One Networks Inc.	Mike Roger
Hydro One Networks Inc. (load data issues)	Stanley But
Hydro One Networks Inc. (load data issues)	Clement Li
Hydro One Networks Inc. (modeling issues)	Steven Low
Innisfil Hydro Distribution Systems Limited	Laurie Ann Cooledge
Kitchener-Wilmot Hydro Inc	Margaret Nanninga
Lakeland Power Distribution Ltd.	Dave Proctor
London Hydro Inc.	Ian McKenzie
London Property Management Association & Energy Probe	Randy Aiken
Milton Hydro Distribution Inc.	Don Thorne
Hydro Ottawa Limited	Jane Scott
Power Workers' Union	Judy Kwik
PowerStream Inc	Bruce Bacon (Phases 1 & 2)
School Energy Coalition	Darryl Seal
Thunder Bay Hydro Electricity Distribution Inc.	Cynthia Domjancic
Toronto Hydro Electric System Limited	Tim Turner
Toronto Hydro Electric System Limited	Anthony Lam
Veridian Connections Inc.	Laurie Stickwood
Vulnerable Energy Consumers Coalition	Bill Harper
Waterloo North Hydro Inc.	Chris Amos
Whitby Hydro Electric Corporation	Ramona Abi-Rashed

OEB Cost Allocation Review Project Team

John Vrantsidis	OEB Staff
Pascale Duguay	OEB Staff (Phases 1 & 2)
Gary Saleba	OEB Consultant
Neil Yeung	OEB Consultant (Phases 1 & 2)
Bruce Bacon	OEB Consultant (Phase 3)
Dean Mountain	OEB Consultant
George Dominy	OEB Consultant
Rose Deng	OEB Contract Staff

Appendix 1.3

Cost Allocation Filing Sequence*

Cost Allocation Filing Tranche 1: November 30, 2006 (26 LDCs)

- Toronto Hydro-Electric System Limited
- Enersource Hydro Mississauga Inc.
- Hydro One Brampton Networks Inc.
- Oshawa PUC Networks Inc.
- Chatham Kent Hydro Inc.
- North Bay Hydro Distribution Ltd.
- Kingston Electricity Distribution Limited
- Newmarket Hydro Ltd.
- Milton Hydro Distribution Inc.
- Innisfil Hydro Distribution Systems Limited
- COLLUS Power Corp.
- Orillia Power Distribution Corporation
- E.L.K. Energy Inc.
- Wasaga Distribution Inc.
- Lakeland Power Distribution Ltd
- Orangeville Hydro Limited
- Lakefront Utilities Inc.
- Tillsonburg Hydro Inc.
- Niagara-On-The-Lake Hydro Inc.
- Tay Hydro Electric Distribution Company Inc.
- Middlesex Power Distribution Corporation
- Hearst Power Distribution Company Limited
- West Perth Power Inc.
- Atikokan Hydro Inc.
- Hydro 2000 Inc.
- Grand Valley Energy Inc.

* This list may not address all currently licensed distributors. If a distributor's status has recently changed as a result of a merger, acquisition or amalgamation, that distributor should review this Report and then contact Board Staff to discuss the number of separate cost allocation filings required.

Cost Allocation Filing Tranche 2: January 15, 2007 (21 LDCs)

- Hydro One Networks Inc.
- Hydro Ottawa Limited
- PowerStream Inc.
- Horizon Utilities Corporation
- ENWIN Powerlines Ltd.
- Barrie Hydro Distribution Inc.
- Burlington Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Greater Sudbury Hydro Inc.
- Brantford Power Inc.
- Bluewater Power Distribution Corporation
- PUC Distribution Inc.
- Whitby Hydro Electric Corporation
- Canadian Niagara Power Inc.
- Halton Hills Hydro Inc.
- St. Thomas Energy Inc.
- Woodstock Hydro Services Inc.
- Kenora Hydro Electricity Corporation Ltd.
- Northern Ontario Wires Inc.
- West Coast Huron Energy Inc.
- Chapleau Public Utilities Corporation

Cost Allocation Filing Tranche 3: February 28, 2007 (20 LDCs)

- London Hydro Inc.
- Veridian Connections Inc.
- Kitchener-Wilmot Hydro Inc.
- Oakville Hydro Electricity Distribution Inc.
- Waterloo North Hydro Inc.
- Cambridge and North Dumfries Hydro Inc.
- Guelph Hydro Electric Systems Inc.
- Niagara Falls Hydro Inc.
- Peterborough Distribution Incorporated
- Essex Powerlines Corporation
- Welland Hydro-Electric System Corp.
- Haldimand County Hydro Inc.
- Festival Hydro Inc.
- Norfolk Power Distribution Inc.
- Peninsula West Utilities Limited
- Erie Thames Powerlines Corporation
- Grimsby Power Incorporated
- Brant County Power Inc.
- Midland Power Utility Corporation
- Parry Sound Power Corporation

Cost Allocation Filing Tranche 4: March 31, 2007 (20 LDCs)

- Westario Power Inc.
- Ottawa River Power Corporation
- Great Lakes Power Limited
- Centre Wellington Hydro Ltd.
- Fort Frances Power Corporation
- Renfrew Hydro Inc.
- Hydro Hawkesbury Inc.
- Rideau St. Lawrence Distribution Inc.
- Clinton Power Corporation
- Wellington North Power Inc.
- Espanola Regional Hydro Distribution Corporation
- Sioux Lookout Hydro Inc.
- Cooperative Hydro Embrun Inc.
- Dutton Hydro Limited
- Terrace Bay Superior Wires Inc.
- Fort Albany Power Corporation
- Kashechewan Power Corporation
- Attawapiskat Power Corporation
- Hydro One Remotes Communities Inc.
- Newbury Power Inc.

Appendix 3.1

Run 1: Rate Classifications and Summary of Load Data Requirements

Rate Classification - Residential	Data Requirements
1. **Residential Class** – accounts for individually metered residential sites taking electricity at ≤ 750 volts (also includes HONI urban class).	Generic load data/(LDC appliance survey if available)/LDC consumption data.
1a. **Residential Urban** – Residential accounts for areas with 15 or more customers per km.	Generic load data/(LDC appliance survey if available)/LDC consumption data.
1b. **Residential Suburban** – Residential accounts for areas with less than 15 customers per km.	Generic load data/ LDC appliance survey/LDC consumption data.
1c. **Residential Suburban Seasonal** – Residential suburban accounts that do not occupy premises at least 8 months out of the year, etc.	Generic load data/LDC appliance survey/LDC consumption data.
1d. **HONI Residential High Density**	Generic load data/appliance survey/consumption data.
1e. **HONI Residential Normal Density**	Generic load data/appliance survey/consumption data.
1f. **HONI Residential Seasonal High Density**	Generic load data/appliance survey/consumption data.
1g. **HONI Residential Seasonal Normal Density**	Generic load data/appliance survey/consumption data.
1h. **HONI Farm Rate Single-Phase**	Generic load data/appliance survey/consumption data.
1i. **Residential Interval Meter**	Interval Meter

Run 1: Rate Classifications and Load Data Requirements

Rate Classification – General Service ≤ 50 kW	**Data Requirements**
2. **General Service less than 50 kW** – non-residential accounts taking service at 750 volts or less with monthly average peak demand ≤ 50 kW.	Residual load shape
2a. **Special Small Commercial User** – non-residential account with forecast peak ≤ 50 kW.	Use residual profile for GS ≤ 50 KW for metered customers and profile for USL for unmetered customers.

Rate Classification – General Service > 50 kW	**Data Requirements**
3. **General Service greater than 50 kW** - non-residential accounts with monthly average peak demand > 50 kW.	Generic load data/LDC industrial grouping data/LDC consumption data.
3a. **GS >50 kW – TOU** non-residential accounts with monthly average peak demand > 50 kW with a TOU meter.	Interval data or if no interval data available use generic load data /LDC industrial grouping data/ LDC consumption data.
3b. **GS >50 kW Interval Metered –** GS >50 with interval metering.	Interval meter data
3c. **Water Sewage Treatment Plant Rate**	If Interval Meter data not available use industry grouping data profile with some adjustments for specific load.
3d. **HONI Farm Rate Three-Phase**	Generic load data consumption data.

Run 1: Rate Classifications and Load Data Requirements

Rate Classification – GS Intermediate Use	**Data Requirements**
4. **General Service Intermediate User or Discrete Demand Range** - Customer load within discrete demand range (e.g. 3000 kW - 5000 kW).	Interval meter data Utility to provide industry grouping breakouts to create load profiles.
4a. **HONI Industrial Commercial General Service Urban Density** - Energy metered customers charged on kWh basis, demand metered customers charged on kW basis.	Use interval meter data if available, otherwise use industry grouping breakouts.
4b. **HONI Industrial Commercial General Service Single Phase G1** - not located in urban zone - Energy metered customers charged on kWh basis, demand metered customers charged on kW basis.	Use Interval meter data if available, otherwise use industry grouping breakouts.
4c **HONI Industrial Commercial General Service Three Phase G3** – not located in urban zone - Energy metered customers charged on kWh basis, demand metered customers charged on kW basis.	Use interval meter data if available, otherwise use industry grouping breakouts.
4d. **HONI Industrial Commercial Sub-Transmission T**- not located in urban zone - Energy metered customers charged on kWh basis, demand metered customers charged on kW basis.	Use interval meter data if available, otherwise use industry grouping breakouts.

Run 1: Rate Classifications and Load Data Requirements

Rate Classification – Large User	Data Requirements
5. **Large User** - accounts with monthly average peak demand greater than 5000 kW.	Interval Meter data
5a. **Special 3TS Rate** - served from a dedicated transformer station.	Interval Meter data
5b. **Special Ford Annex Rate** – served from a dedicated transformer station.	Interval Meter data
5c. **Special Large Customer Rate** – An LDC has a large use rate with one customer.	Interval Meter data
5d. **HONI acquired utilities' Large User Rates**	Interval Meter data
5e. **HONI LV Facilities** - i) Direct Customers (with monthly average peak demand greater than 5000 kW) and ii) Embedded Distributors, that are treated as HONI LV distribution customers	Interval Meter data

Run 1: Rate Classifications and Load Data Requirements

Rate Classification – Other	Data Requirements
6. **Street Lights**	Use distributor's OEB approved load profile.
6a. **Street Lights TOU**	It is assumed there is an approved load profile.
7. **Sentinel Lights**	Use distributor's OEB approved street light load profile.
8. **Unmetered Scattered Loads (to usually be treated part of GS<50 kW) –** A distributor whose 2006 USL rate was set using the special rate design method arrived at during the 2006 EDR consultations, must include USL in the General Service <50 kW classification. USL to include photosensitive and non-photosensitive USL loads.	Generally, use load profile of General Service < 50 kW classification NB: Other USL specific costs to be captured by Run 1 in USL metering credit.
9. **Load Displacement Generation** – Usually to be included in appropriate main rate classification in Run 1 (but if LDC considers it a fully separate rate class, must have own load data); customers to be defined using current definition for standby rates	For most distributors in Run 1, no separate load data required (i.e. use load data of main rate classification) NB: Other costs to be identified for LDG charge or credit.
10. **Embedded Distributor –** host distributor transfers power to an embedded distributor. To be modeled as separate rate classification in Run 1 only where there is a separate charge in current rates and it differs from other approved rates.	Interval Meter data

Run 2: Rate Classifications and Summary Load Data Requirements
Same as Run 1 with the following exceptions

NB: To use 2006 EDR data when assessing rate classification changes

Rate Classification	Data Requirements
3a. **GS >50 kW – TOU** Classification to be eliminated Rename as "Intermediate" if it meets legacy test for intermediate (customer load represents 10% or more of the utility's load); or rename classification as appropriate if it has a discrete demand range; otherwise, roll into GS > 50 kW classification. Elimination of legacy TOU customers will not apply to (HONI) interim TOU rate.	Interval data or if no interval data available use generic load data /LDC industrial grouping data/ LDC consumption data.
5a **New Large Use Class** – to address where LDC has GS customer above 5,000 kW.	If customer is part of GS>50kW or GS intermediate class etc., interval meter data should be available.
6a. **Street Lights TOU** Classification to be renamed "Street Lights" and rolled into Non TOU Street Light classification if applicable.	To be assumed there is an approved load profile.
8. **Unmetered Scattered Loads –** To be modeled as separate rate classification. Future test year filers must consider need for adjustment for treatment of heating mats.	Refer to Chapter 3 of Report for details.
9. **Load Displacement Generation** – Load displacement customers with standby service requirements of greater than 500 kWs of load. To be modeled as a (single) separate rate classification.	Actual metered usage for the customers with load displacement will be used to construct the load profiles.

Rate Classification	Data Requirements
10. **Embedded Distributor –** host distributor transfers power to an embedded distributor. To be modeled as separate classification by all LDC serving such customers.	Interval Meter data

Optional Run 3: Rate Classifications and Load Data Requirements
Same as Run 2 with the following exceptions:

Rate Classification	Data Requirements
9. **Load Displacement Generation** – Load displacement customers that displace greater than 500 kWs of load. If modeled as a fully separate rate classification, own load data required.	Alternative Method: Add actual or estimated metered generator load displacement to the metered usage. If an estimated amount has been added to the metered usage, explanation and calculation must be filed. Diversity must be addressed.
10. **Merchant Generation**	Distributor to consider and justify appropriate load shape if modeled as separate rate classification.
11. **Hybrid Load Displacement/ Merchant Generation**	Distributor to consider and justify appropriate load shape if modeled as separate rate classification.
12. Other If distributor adds new separate rate classification, must also provide supporting load data.	Current density and seasonal classifications can be eliminated but new density and seasonal classifications are not allowed. NB: Distributor not allowed to eliminate current polyphase classification.

Appendix 4.1

Allocation of Revenue Off-set Accounts

Acct.	Description	Allocation Method to Rate Classification
4082	Retail Services Revenues	Number of Weighted bills
4084	Service Transaction Requests (STR) Revenues	Number of Weighted bills
4090	Electric Services Incidental to Energy Sales	Number of Weighted bills
4205	Interdepartmental Rents	Net Fixed Assets
4210	Rent from Electric Property	Net Fixed Assets
4215	Other Utility Operating Income	Net Fixed Assets
4220	Other Electric Revenues	Net Fixed Assets
4225	Late Payment Charges	Historical class allocation – 3 year average
4235	Miscellaneous Service Revenues	Number of Weighted bills
4240	Provision for Rate Refunds	Net Fixed Assets
4245	Government Assistance Directly Credited to Income	Net Fixed Assets
4305	Regulatory Debits	Net Fixed Assets
4310	Regulatory Credits	Net Fixed Assets
4315	Revenues from Electric Plant Leased to Others	Net Fixed Assets
4320	Expenses of Electric Plant Leased to Others	Net Fixed Assets
4325	Revenues from Merchandise, Jobbing, Etc.	Net Fixed Assets
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Net Fixed Assets
4335	Profits and Losses from Financial Instrument Hedges	Net Fixed Assets
4340	Profits and Losses from Financial Instrument Investments	Net Fixed Assets
4345	Gains from Disposition of Future Use Utility Plant	Net Fixed Assets
4350	Losses from Disposition of Future Use Utility Plant	Net Fixed Assets
4355	Gain on Disposition of Utility and Other Property	Net Fixed Assets
4360	Loss on Disposition of Utility and Other Property	Net Fixed Assets
4365	Gains from Disposition of Allowances for Emission	Net Fixed Assets
4370	Losses from Disposition of Allowances for Emission	Net Fixed Assets
4390	Miscellaneous Non-Operating Income	Net Fixed Assets
4395	Rate-Payer Benefit Including Interest	Net Fixed Assets
4398	Foreign Exchange Gains and Losses, Including	Net Fixed Assets

	Amortization	
4405	Interest and Dividend Income	Net Fixed Assets
4415	Equity in Earnings of Subsidiary Companies	Net Fixed Assets

Appendix 6.1

Grouping of Accounts by Allocator

USoA Account #	Accounts	Classification Allocator	Group
1565	Conservation and Demand Management Expenditures and Recoveries	CDMPP	1
1805-1	Land Station >50 kV	TCP	2
1806-1	Land Rights Station >50 kV	TCP	2
1808-1	Buildings and Fixtures > 50 kV	TCP	2
1810-1	Leasehold Improvements >50 kV	TCP	2
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP	2
1825-1	Storage Battery Equipment > 50 kV	TCP	2
1805-2	Land Station <50 kV	DCP	3
1806-2	Land Rights Station <50 kV	DCP	3
1808-2	Buildings and Fixtures < 50 KV	DCP	3
1810-2	Leasehold Improvements <50 kV	DCP	3
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP	3
1825-2	Storage Battery Equipment <50 kV	DCP	3
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP	4
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP	4
1840-3	Underground Conduit - Bulk Delivery	BCP	4
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP	4
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP	5
1830-4	Poles, Towers and Fixtures - Primary	PNCP	5
1835-4	Overhead Conductors and Devices – Primary	PNCP	5
1840-4	Underground Conduit - Primary	PNCP	5
1845-4	Underground Conductors and Devices – Primary	PNCP	5
1830-5	Poles, Towers and Fixtures – Secondary	SNCP	6
1835-5	Overhead Conductors and Devices – Secondary	SNCP	6

1840-5	Underground Conduit - Secondary	SNCP	6
1845-5	Underground Conductors and Devices – Secondary	SNCP	6
1850	Line Transformers	LTNCP	7
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	CEN	8
1855	Services	CWCS	9
1860	Meters	CWMC	10
1608	Franchises and Consents	NFA ECC	11
1905	Land	NFA ECC	11
1906	Land Rights	NFA ECC	11
1908	Buildings and Fixtures	NFA ECC	11
1910	Leasehold Improvements	NFA ECC	11
1915	Office Furniture and Equipment	NFA ECC	11
1920	Computer Equipment - Hardware	NFA ECC	11
1925	Computer Software	NFA ECC	11
1930	Transportation Equipment	NFA ECC	11
1935	Stores Equipment	NFA ECC	11
1940	Tools, Shop and Garage Equipment	NFA ECC	11
1945	Measurement and Testing Equipment	NFA ECC	11
1950	Power Operated Equipment	NFA ECC	11
1955	Communication Equipment	NFA ECC	11
1960	Miscellaneous Equipment	NFA ECC	11
1970	Load Management Controls - Customer Premises	NFA ECC	11
1975	Load Management Controls - Utility Premises	NFA ECC	11
1980	System Supervisory Equipment	NFA ECC	11
1990	Other Tangible Property	NFA ECC	11
2005	Property Under Capital Leases	NFA ECC	11
2010	Electric Plant Purchased or Sold	NFA ECC	11
1995	Contributions and Grants - Credit	Break out	12
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Break out	12
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Break out	12
3046	Balance Transferred From Income	NFA	13
4080	Distribution Services Revenue	CREV	14
4082	Retail Services Revenues	CWNB	15
4084	Service Transaction Requests (STR) Revenues	CWNB	15
4090	Electric Services Incidental to Energy Sales	CWNB	15

4235	Miscellaneous Service Revenues	CWNB	15
4205	Interdepartmental Rents	NFA	16
4210	Rent from Electric Property	NFA	16
4215	Other Utility Operating Income	NFA	16
4220	Other Electric Revenues	NFA	16
4240	Provision for Rate Refunds	NFA	16
4245	Government Assistance Directly Credited to Income	NFA	16
4305	Regulatory Debits	NFA	16
4310	Regulatory Credits	NFA	16
4315	Revenues from Electric Plant Leased to Others	NFA	16
4320	Expenses of Electric Plant Leased to Others	NFA	16
4325	Revenues from Merchandise, Jobbing, Etc.	NFA	16
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	NFA	16
4335	Profits and Losses from Financial Instrument Hedges	NFA	16
4340	Profits and Losses from Financial Instrument Investments	NFA	16
4345	Gains from Disposition of Future Use Utility Plant	NFA	16
4350	Losses from Disposition of Future Use Utility Plant	NFA	16
4355	Gain on Disposition of Utility and Other Property	NFA	16
4360	Loss on Disposition of Utility and Other Property	NFA	16
4365	Gains from Disposition of Allowances for Emission	NFA	16
4370	Losses from Disposition of Allowances for Emission	NFA	16
4390	Miscellaneous Non-Operating Income	NFA	16
4395	Rate-Payer Benefit Including Interest	NFA	16
4398	Foreign Exchange Gains and Losses, Including Amortization	NFA	16
4405	Interest and Dividend Income	NFA	16
4415	Equity in Earnings of Subsidiary Companies	NFA	16
4225	Late Payment Charges	LPHA	17
4705	Power Purchased	CEN EWMP	18
4708	Charges-WMS	CEN EWMP	18
4710	Cost of Power Adjustments	CEN EWMP	18

4712	Charges-One-Time	CEN EWMP	18
4715	System Control and Load Dispatching	CEN EWMP	18
4720	Other Expenses	CEN EWMP	18
4725	Competition Transition Expense	CEN EWMP	18
4730	Rural Rate Assistance Expense	CEN EWMP	18
4714	Charges-NW	CEN	19
4716	Charges-CN	CEN	19
5005	Operation Supervision and Engineering	1815-1855	20
5010	Load Dispatching	1815-1855	20
5085	Miscellaneous Distribution Expense	1815-1855	20
5105	Maintenance Supervision and Engineering	1815-1855	20
5012	Station Buildings and Fixtures Expense	1808	21
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808	21
5014	Transformer Station Equipment - Operation Labour	1815	22
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815	22
5112	Maintenance of Transformer Station Equipment	1815	22
5016	Distribution Station Equipment - Operation Labour	1820	23
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820	23
5114	Maintenance of Distribution Station Equipment	1820	23
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835	24
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835	24
5030	Overhead Subtransmission Feeders – Operation	1830 & 1835	24
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835	24
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835	24
5035	Overhead Distribution Transformers-Operation	1850	25
5055	Underground Distribution Transformers - Operation	1850	25
5160	Maintenance of Line Transformers	1850	25
5040	Underground Distribution Lines and	1840 & 1845	26

	Feeders - Operation Labour		
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845	26
5050	Underground Subtransmission Feeders – Operation	1840 & 1845	26
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845	26
5065	Meter Expense	CWMC	27
5070	Customer Premises - Operation Labour	CCA	28
5075	Customer Premises - Materials and Expenses	CCA	28
5120	Maintenance of Poles, Towers and Fixtures	1830	29
5125	Maintenance of Overhead Conductors and Devices	1835	29
5130	Maintenance of Overhead Services	1855	30
5155	Maintenance of Underground Services	1855	30
5145	Maintenance of Underground Conduit	1840	31
5150	Maintenance of Underground Conductors and Devices	1845	32
5175	Maintenance of Meters	1860	33
5305	Supervision	CWNB	34
5315	Customer Billing	CWNB	34
5320	Collecting	CWNB	34
5325	Collecting- Cash Over and Short	CWNB	34
5330	Collection Charges	CWNB	34
5340	Miscellaneous Customer Accounts Expenses	CWNB	34
5310	Meter Reading Expense	CWMR	35
5335	Bad Debt Expense	BDHA	36
5405	Supervision	O&M	37
5410	Community Relations - Sundry	O&M	37
5425	Miscellaneous Customer Service and Informational Expenses	O&M	37
5505	Supervision	O&M	37
5510	Demonstrating and Selling Expense	O&M	37
5515	Advertising Expense	O&M	37
5520	Miscellaneous Sales Expense	O&M	37
5605	Executive Salaries and Expenses	O&M	37
5610	Management Salaries and Expenses	O&M	37
5615	General Administrative Salaries and Expenses	O&M	37

5620	Office Supplies and Expenses	O&M	37
5625	Administrative Expense Transferred Credit	O&M	37
5630	Outside Services Employed	O&M	37
5640	Injuries and Damages	O&M	37
5645	Employee Pensions and Benefits	O&M	37
5650	Franchise Requirements	O&M	37
5655	Regulatory Expenses	O&M	37
5660	General Advertising Expenses	O&M	37
5665	Miscellaneous General Expenses	O&M	37
5670	Rent	O&M	37
5675	Maintenance of General Plant	O&M	37
5680	Electrical Safety Authority Fees	O&M	37
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	O&M	37
5735	Amortization of Deferred Development Costs	O&M	37
5740	Amortization of Deferred Charges	O&M	37
6205	Donations	O&M	37
6210	Life Insurance	O&M	37
6215	Penalties	O&M	37
6225	Other Deductions	O&M	37
5096	Other Rent	O&M	37
5415	Energy Conservation	CDMPP	38
5420	Community Safety Program	NFA ECC	39
5635	Property Insurance	NFA ECC	39
5685	Independent Market Operator Fees and Penalties	NFA	40
5705	Amortization Expense - Property, Plant, and Equipment	Break out	41
5710	Amortization of Limited Term Electric Plant	Break out	41
5715	Amortization of Intangibles and Other Electric Plant	Break out	41
5720	Amortization of Electric Plant Acquisition Adjustments	Break out	41
6005	Interest on Long Term Debt	NFA	42
6105	Taxes Other Than Income Taxes	NFA	42
6110	Income Taxes	NFA	42

Glossary of Terms

Classification Allocator	Description
CDMPP	CDM Participation Percentage
TCP	Transformation Coincident Peak
DCP	Distribution Coincident Peak
BCP	Bulk Coincident Peak
PNCP	Primary Non Coincident Peak
SNCP	Secondary Non Coincident Peak
LTNCP	Line Transformer Non Coincident Peak
CEN	Customer Energy
CWCS	Customer Weighted Count on Secondary
CWMC	Customer Weighted Meter Capital
NFA ECC	Net Fixed Assets Excluding Contributed Capital
Break Out	The Account is broken out by User in the Model
CREV	Customer Distribution Revenue
CWNB	Customer Weighted Number of Bills
NFA	Net Fixed Assets
LPHA	Late Payment Historical Average
CEN EWMP	Customer Energy Excluding Wholesale Market Participants
1815-1855	Assets in Accounts 1815 to 1855
1808	Assets in Account 1808
1815	Assets in Account 1815
1820	Assets in Account 1820
1830 & 1835	Assets in Accounts 1830 & 1825
1850	Assets in Account 1850
1840 & 1845	Assets in Accounts 1840 & 1845
CCA	Customer Count All (i.e. Total System)
1830	Assets in Account 1830
1835	Assets in Account 1835
1855	Assets in Account 1855
1840	Assets in Account 1840
1845	Assets in Account 1845
1860	Assets in Account 1860
CWMR	Customer Weighted Meter Reads
BDHA	Bad Debt Historical Average
O&M	Operations and Maintenance – (i.e. Composite)

Appendix 6.2

Identification of Customers Served at Bulk, Primary and Secondary

The examples in this Appendix have been developed to assist with the understanding of how the customer number is entered into the filing model to implement the separation of bulk, primary and secondary assets.

Example 1

The following is an example that assumes the distributor has bulk assets shared by 100% of the customers and includes the following customer characteristics for Residential, General Service < 50 kW, General Service > 50 kW and Large Use classifications:

a) Number of Customers by Rate Classification

Rate Classification	Number of Customers
Residential	1,000
General Service < 50 kW	500
General Service > 50 kW	100
Large Use	7

b) Number of Residential customers taking power from the secondary assets through the primary and bulk assets is 1,000.
c) Number of General Service < 50 kW customers taking power from the secondary assets through the primary and bulk assets is 500.
d) Number of General Service > 50 kW customers taking power from the secondary assets through the primary and bulk assets is 50.
e) Number of General Service > 50 kW customers taking power from the primary assets through the bulk assets is 50.
f) Number of Large Use customers taking power from the primary assets through the bulk assets is 2.
g) Number of Large Use customer taking power form the bulk assets is 5.

The following outlines the resulting numbers of customers using the various asset groupings, for Example 1.

Class	Bulk	Primary	Secondary
Residential	1,000	1,000	1,000
General Service <50 kW	500	500	500
General Service >50 kW	100	100	50
Large Use	7	2	

Example 2

The following is an example that assumes the distributor does not have bulk assets and includes the following customer characteristics for Residential, General Service < 50 kW, General Service > 50 kW and Large Use classifications:

a) Number of Customers by Rate Classification

Rate Classification	Number of Customers
Residential	1,000
General Service < 50 kW	500
General Service > 50 kW	100
Large Use	7

b) Number of Residential customers taking power from the secondary assets through the primary assets is 1,000.
c) Number of General Service < 50 kW customers taking power from the secondary assets through the primary assets is 500.
d) Number of General Service > 50 kW customers taking power from the secondary assets through the primary assets is 50.
e) Number of General Service > 50 kW customers taking power from the primary assets is 50.
f) Number of Large Use customers taking power from the primary assets is 7.

The following outlines the resulting numbers of customers using the various asset groupings, for Example 2:

Class	Bulk	Primary	Secondary
Residential		1,000	1,000
General Service <50 kW		500	500
General Service >50 kW		100	50
Large Use		7	

Example 3

The following is an example that assumes the distributor has a bulk system that does not provide service equally to all customers and includes the following customer characteristics for Residential, General Service < 50 kW, General Service > 50 kW and Large Use classifications:

a) Number of Customers by Rate Classification

Rate Classification	Number of Customers
Residential	1,000
General Service < 50 kW	500
General Service > 50 kW	100
Large Use	7

b) Number of Residential customers taking power from the secondary assets through the primary and bulk assets is 500.
c) Number of Residential customers taking power from the secondary assets through the primary assets only is 500.
d) Number of General Service < 50 kW customers taking power from the secondary assets through the primary and bulk assets is 250.
e) Number of General Service < 50 kW customers taking power from the secondary assets through the primary assets only is 250.
f) Number of General Service > 50 kW customers taking power from the secondary assets through the primary and bulk assets is 50.
g) Number of General Service > 50 kW customers taking power directly from the primary assets is 50.
h) Number of Large Use customers taking power from the primary assets through the bulk assets is 2.
i) Number of Large Use customers taking power from the primary assets directly is 3.
j) Number of Large Use customers taking power from the bulk assets is 2.

The following outlines the resulting numbers of customers using the various asset groupings, for Example 3:

Class	Bulk	Primary	Secondary
Residential	500	1,000	1,000
General Service <50 kW	250	500	500
General Service >50 kW	50	100	50
Large Use	4	5	

Appendix 7.1

100% Demand Related Accounts/Sub-accounts

1805-1	Land Station >50 kV
1805-2	Land Station <50 kV
1806-1	Land Rights Station >50 kV
1806-2	Land Rights Station <50 kV
1808-1	Buildings and Fixtures > 50 kV
1808-2	Buildings and Fixtures < 50 KV
1810-1	Leasehold Improvements >50 kV
1810-2	Leasehold Improvements <50 kV
1815	Transformer Station Equipment - Normally Primary above 50 kV
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)
1825-1	Storage Battery Equipment > 50 kV
1825-2	Storage Battery Equipment <50 kV
1830-3	Poles, Towers and Fixtures – Subtransmission Bulk Delivery
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery
1840-3	Underground Conduit – Bulk Delivery
1845-3	Underground Conductors and Devices - Bulk Delivery
5012	Station Buildings and Fixtures Expense
5014	Transformer Station Equipment - Operation Labour
5015	Transformer Station Equipment - Operation Supplies and Expenses
5016	Distribution Station Equipment - Operation Labour
5017	Distribution Station Equipment - Operation Supplies and Expenses
5030	Overhead Subtransmission Feeders – Operation
5050	Underground Subtransmission Feeders – Operation
5110	Maintenance of Buildings and Fixtures - Distribution Stations
5112	Maintenance of Transformer Station Equipment
5114	Maintenance of Distribution Station Equipment

Appendix 7.2

100% Customer Related Accounts/Sub-accounts

1855	Services
1860	Meters
1565	Conservation and Demand Management Expenditures and Recoveries
5065	Meter Expense
5070	Customer Premises - Operation Labour
5075	Customer Premises - Materials and Expenses
5130	Maintenance of Overhead Services
5155	Maintenance of Underground Services
5175	Maintenance of Meters
5305	Supervision
5315	Customer Billing
5320	Collecting
5325	Collecting- Cash Over and Short
5330	Collection Charges
5340	Miscellaneous Customer Accounts Expenses
5310	Meter Reading Expense
5335	Bad Debt Expense
5415	Energy Conservation

Appendix 7.3

Joint Related Accounts/Sub-accounts

1830-4	Poles, Towers and Fixtures – Primary
1830-5	Poles, Towers and Fixtures – Secondary
1835-4	Overhead Conductors and Devices – Primary
1835-5	Overhead Conductors and Devices – Secondary
1840-4	Underground Conduit – Primary
1840-5	Underground Conduit – Secondary
1845-4	Underground Conductors and Devices – Primary
1845-5	Underground Conductors and Devices – Secondary
1850	Line Transformers
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders – Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
5055	Underground Distribution Transformers – Operation
5090	Underground Distribution Lines and Feeders - Rental Paid
5095	Overhead Distribution Lines and Feeders - Rental Paid
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5160	Maintenance of Line Transformers

Appendix 7.4

Pro-rata Related Accounts/Sub-accounts

5005	Operation Supervision and Engineering
5010	Load Dispatching
5085	Miscellaneous Distribution Expense
5105	Maintenance Supervision and Engineering

Appendix 7.5

Generic Minimum System Results – Ontario Studies					
				Customer Component	
By Density			Density (Cust/km)	Line Transformer	Distribution
			Low	60%	60%
			Medium	40%	40%
			High	30%	35%
Results of Ontario Studies					
Average by Density			Low	62%	61%
			Medium	43%	43%
			High	31%	36%
			Average all	40%	43%
		Customer Component			
Utility Name	Density (Cust/km)	Line Transformer	Overhead Feeders	Underground Feeders	Combined OH/UG
Guelph - Bare Bone	Medium	27%	48%	34%	41%
Guelph - Smallest Installed	Medium	54%	99%	67%	83%
Milton	Medium	64%	44%	32%	38%
MEA 1998 study	Medium	27%	36%	15%	26%
Strata 1 (note 1)	Medium	42%	52%	25%	39%
Strata 2 (note 1)	Medium	26%	51%	27%	39%
Strata 3 (note 1)	Medium	29%	50%	29%	40%
Wasaga Beach	Medium	71%	61%	13%	37%
Rural Study (Ont Hydro)	Low	62%	61%	61%	61%
Etobicoke (Tx weighted oh/ug)	High	38%	63%	66%	65%
North York Hydro (Tx Weighted)	High	16%	32%	11%	22%
Toronto Hydro	High	23%	23%	23%	23%
Note 1 :					
MEA February 1998					
Strata 3 - utilities with over 40% of distribution plant underground					
Strata 2 - utilities with less than 40% and over 1000 Residential customers					
Strata 1 - Utilities with less than 40% underground and less than 1000 residential customers					
The 10 largest utilities were excluded from these stratifications.					

Appendix 9.1

Weightings for Billing Activities (Select)

Rate Classification	Weighting for Billing Activities
Residential	1
General Service < 50 kW	2
General Service > 50 kW	7
Large User	15
Sentinel Lights	O.1

Appendix 9.2

Installed Meter Capital Costs (Select)

Meter Type	Installed Meter Capital Cost
Single Phase 200 Amp – Urban	50
Single Phase 200 Amp – Rural	150
Central Meter (Costs to be updated)	250
Network Meter (Costs to be updated)	225
Three-phase - No demand	210
Smart Meters (Costs to be updated)	300
Demand without IT (usually three-phase)	500
Demand with IT	2,100
Demand with IT and Interval Capability - Secondary	2,300
Demand with IT and Interval Capability - Primary	10,000
Demand with IT and Interval Capability -Special (WMP)	40,000

Appendix 9.3

Meter Reading Factors (Select)

Meter Type	Meter Reading Factors
Residential - Urban – Outside	1.00
Residential - Urban - Outside with other services	1.00
Residential - Urban – Inside	2.00
Residential - Urban – Inside - with other services	1.00
Residential - Rural - Outside with other services	2.00
GS – Walking	2.00
GS – Walking - with other services	3.00
GS – Vehicle with other services --- TOU Read	3.00
GS – Vehicle with other services	3.00
Interval	49.00

Appendix 9.4

Weightings for Services (Select)

Rate Classification	Weighting for Services
Residential	1
General Service < 50 kW	2
General Service > 50 kW	10
Large User	30

Appendix 11.1

Filing Question: Load Displacement Customers - Further Potential Distribution Cost Savings or Burdens

When completing Run 1 and Run 2 of the filing, all distributors with load displacement customers should review the below list to ascertain if any distribution system net costs (i.e. gross costs minus savings) included in the data supporting the approved 2006 EDR rates can be attributed to load displacement customers. If a distributor can also identify any further savings or costs associated with load displacement customers over and above items reflected in its 2006 rate application, then a LDG Run 3 should be filed including the same (and the Filing Summary should highlight this).

For Run 1, the definition of customer used for current standby rate service will apply. For Run 2 and Run 3, LDG customers are defined as those requiring greater than 500 kW of standby service.

The Technical Advisory Team identified the following as potential cost reductions on a distribution system:

- ability to defer or avoid commissioning of new delivery system assets and associated operating costs
- extending the service life of distribution assets and/or reducing the maintenance of these assets
- generally reduced distribution line losses (but not in all cases)
- potentially enhanced distribution system flexibility and reliability such as continued service during widespread outages.

Some of the potential cost burdens on various parts of the distribution system may include:

- incremental engineering, contracting, metering, and/or billing costs
- incremental capital and/or maintenance costs (e.g. associated with switching operations, communications and monitoring)
- need to invest in different system controls and protections (e.g. may need to purchase or upgrade SCADA) and need to change operating practice with regard to safety.

Some of the unknown impacts may include:

- impact on voltage stability.

Appendix 12.1

Accounts included in Calculation of Customer Unit Costs assuming Avoided Costs and Directly Related Customer Costs

Avoided Costs

Account #	Accounts
Distribution Plant	
1860	Meters
Accum. Amortization	
2105	Amortization of Electricity Utility Plant – Meters only
Misc. Revenues	
4082	Retail Services Revenues
4084	Service Transaction Requests (STR) Revenues
4090	Electric Services Incidental to Energy Sales
4220	Other Electric Revenues
4225	Late Payment Charges
Operation	
5065	Meter Expense
5070	Customer Premises – Operation Labour
5075	Customer Premises – Materials and Expenses
Maintenance	
5175	Maintenance of Meters
Billing & Collection	
5310	Meter Reading Expense
5315	Customer Billing
5320	Collecting
5325	Collecting – Cash Over and Short
5330	Collection Charges
Amortization of Assets	
5705	Amortization Expense – Only meters

Directly Related Customer Costs

Avoided costs plus administration and general expenses associated with the above direct operation, maintenance, billing and collection costs as well as a proportion of general plant assigned to meter assets.

Appendix 12.2

Primary and Secondary Conductors and Poles Cost Pools Calculation

The costs set out in Appendix 12.2 will list the primary and secondary conductors and poles cost pool to be generated by the filing model for potential future reference. Please note the sub-account references listed below are for modeling purposes only and do not relate to actual USoA references.

Proposal - Primary Conductors and Poles Cost Pools Calculation

a) Depreciation on sub-account 1830-4 - Poles, Towers and Fixtures – Primary
b) Depreciation on sub-account 1835-4 - Overhead Conductors and Devices – Primary
c) Depreciation on sub-account 1840-4 - Underground Conduit – Primary.
d) Depreciation on sub-account 1845-4 - Underground Conductors and Devices – Primary
e) Primary component of operation expense on overhead distribution lines and feeders – Accounts 5020 and 5025
f) Primary component of operation expense on underground distribution lines and feeders – Accounts 5040 and 5045
g) Primary component of underground distribution lines and feeders - rental paid – Account 5090
h) Primary component of overhead distribution lines and feeders - rental paid – Account 5095
i) Primary component of maintenance expense on poles, towers and fixtures - Account 5120
j) Primary component of maintenance expense on overhead conductors and devices – Account 5125
k) Primary component of maintenance expense on overhead distribution lines and feeders right of way – Account 5135
l) Primary component of maintenance expense on underground conduit – Account 5145
m) Primary component of maintenance expense on underground conductors and devices – Account 5150
n) A pro rata share of accounts 5005, 5010, 5085 and 5105 based on the distribution assets identified in a) to d).
o) General plant allocated to these primary assets.
p) Administration and general expenses allocated to these primary assets.
q) PILs and return on equity and debt that would be allocated to the net fixed assets associated with the assets listed in a) to d) and o) .

Proposal - Secondary Conductors and Poles Cost Pool Calculation

The following costs will be included in the secondary conductors and poles cost pool to be generated by the filing model for future reference.

a) Depreciation on sub-account 1830-5 - Poles, Towers and Fixtures – Secondary
b) Depreciation on sub-account 1835-5 - Overhead Conductors and Devices – Secondary
c) Depreciation on sub-account 1840-5 - Underground Conduit – Secondary
d) Depreciation on sub-account 1845-5 - Underground Conductors and Devices – Secondary
e) Secondary component of operation expense on overhead distribution lines and feeders – Accounts 5020 and 5025
f) Secondary component of operation expense on underground distribution lines and feeders – Accounts 5040 and 5045
g) Secondary component of underground distribution lines and feeders - rental paid – Account 5090
h) Secondary component of overhead distribution lines and feeders - rental paid – Account 5095
i) Secondary component of maintenance expense on poles, towers and fixtures - Account 5120
j) Secondary component of maintenance expense on overhead conductors and devices – Account 5125
k) Secondary component of maintenance expense on overhead distribution lines and feeders – Account 5135
l) Secondary component of maintenance expense on underground conduit – Account 5145
m) Secondary component of maintenance expense on underground conductors and devices – Account 5150
n) A pro rata share of accounts 5005, 5010, 5085 and 5105 based on the distribution assets identified in a) to d).
o) General plant allocated to these secondary assets
p) Administration and general expenses allocated to these secondary assets
q) PILs and return on equity and debt that would be allocated to the net fixed assets associated with the assets listed in a) to d) and o).