Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

Ontario Energy Board

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications

June 28, 2010

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Chapter 2 Filing requirements for electricity transmission and distribution companies' cost of service rate applications, based on a forward test year

2.0 Preamble

Framework

The Ontario Energy Board regulates electricity transmission and distribution companies using a combination of annual incentive rate mechanism adjustments and periodic cost of service reviews. For rates adjusted through a cost of service review, forecast test year data is normally used.

An application to the Board by a regulated company should provide sufficient detail to enable the Board to make a determination as to whether the proposed rates are just and reasonable. The material presented is the applicant's evidence and the onus is on the applicant to prove the need for, and the basis of, the proposed new rates. A clearly written application that advocates the need for the proposed rates, complete with sufficient evidence and justification for those rates, is essential to facilitate an efficient regulatory review and a timely decision.

Unless specifically identified, the use of the words "utility", "utilities", "applicant" or "applicants" in this document refers to both transmitters and distributors. The use of the phrase "Board-approved" in these filing requirements typically refers to the set of data used by the Board as the basis for approving the most recent cost based rates. It does not mean that the Board, in fact, "approved" any of the data, only that the final approved rates were based on that data.

The examination of and decision on an application is based on the evidence filed in that case. This ensures that all interested parties to the proceeding have an opportunity to see the evidence, participate meaningfully in the Board's process in any given case, and understand the reasons for a decision. Consequently, the applicant must at a minimum, meet all of the applicable Filing Requirements.

The Board will consider an application complete if it meets all of the applicable Filing Requirements. If an application does not meet all of these requirements, the applicant must provide an explanation as to why this is the case. Based on this explanation, the Board will assess whether or not the application can proceed.

The Filing Requirements contained in this chapter outline all of the relevant information necessary for a complete application. Section 2.1, Introduction, provides an overview of general requirements as well as information on key planning parameters. Sections 2.2 to 2.10 provide requirements for each of the major exhibits covered by the application (e.g. Section 2.4 addresses operating revenue, while Section 2.8 addresses cost allocation).

The various appendices at the end of the chapter are linked to each of these sections and provide schedules to be completed by the applicant to facilitate the filing of all required information. (e.g. Appendix 2-O Cost Allocation provides tables related to Revenue-to-Cost Ratios and Test Year Revenue Impacts).

Any application made pursuant to section 92 of the *Ontario Energy Board Act, 1998* (i.e. Leave to Construct) is subject to the requirements of chapters 4 and 5 of the Filing Requirements (see Section 2.3 dealing with capital budgets for projects with construction commencing in the Test Year).

When changes or updates to a filing are necessary, an overall explanation of the changes should be provided, along with revisions to the affected evidence and related schedules.

The Board remains cognizant of the large number of interrogatories that the existing process can generate. The frequent requirement for a large number of interrogatories suggests that applicants and interested parties do not have a common understanding of the information required to support a rate application. The Board advises applicants to strategically consider the clarity and materiality of the evidence, so that the evidence can be well understood by all parties thereby reducing the need for interrogatories.

2.1 Introduction

The basic format of any application by a distributor or transmitter for a forward test year cost of service filing should consist of the following nine Exhibits:

Exhibit 1	Administrative Documents
Exhibit 2	Rate Base
Exhibit 3	Operating Revenue
Exhibit 4	Operating Costs
Exhibit 5	Cost of Capital and Capital Structure
Exhibit 6	Calculation of Revenue Deficiency or Surplus
Exhibit 7	Cost Allocation
Exhibit 8	Rate Design
Exhibit 9	Deferral and Variance Accounts

If any significant element of these filing requirements is not included in the filing, the application may be deemed by the Board to be incomplete and may not be processed until the missing information is provided. If an applicant has provided all relevant exhibits, but has not met all of the informational requirements outlined in this chapter, the missing information will be requested through subsequent stages of discovery, such as interrogatories, and may lead to delays in processing the application.

Other exhibits may also be included in an application to document other proposals for which the applicant is seeking Board review and approval in the application. These could be related to, for example, Lost Revenue Adjustment Mechanism and Shared Savings Mechanism recoveries. Guidance on the material to be included in such exhibits is provided through applicable guidelines or other documentation that the Board or other agency, such as the Ontario Power Authority may provide, or that may be contained in applicable legislation or regulation.

The Filing Requirements incorporate a series of appendices which include tables required to be completed by the applicant. These tables are available on the Board's web site.

2.1.1 Key References

The references listed below are key to interpreting these Filing Requirements.

- Uniform System of Accounts (USoA);
- Generally Accepted Accounting Principles (GAAP);
- Generally Accepted Regulatory Principles (GARP);
- International Financial Reporting Standards (IFRS);
- Report of the Board on the Transition to International Financial Reporting Standards, July 28, 2009;
- Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006;
- Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008;
- Supplemental Report, and Addendum, of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008 and January 28, 2009;
- Cost Allocation Informational Filing Guidelines for Electricity Distributors, November 15, 2006;
- Application of Cost Allocation for Electricity Distributors, November 28, 2007;
- Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative, July 31, 2009;
- Guidelines for Electricity Distributor Conservation and Demand Management, March 28, 2008;
- Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009;
- Filing Requirements: Distribution System - Filing Under Deemed Conditions of Licence, March 25, 2010 and other Green Energy Act related documents discussed in section 2.1.4;
- G-2008-0001 Guideline Electricity Distribution Retail Transmission Service Rates, October 22, 2008 and any subsequent updates; and
- G-2008-0002 Guideline Smart Meter Funding and Cost Recovery, October 22, 2008 and any subsequent updates;
- G-2009-0300 Guidelines: Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities, September 15, 2009.

2.1.2 General Requirements

The requirements outlined below are general requirements that are applicable to each Exhibit in the application:

- Written direct evidence is to be included before data schedules;
- Average of the opening and closing fiscal year balances must be used for items in rate base;
- Total Capitalization (debt and equity) must equate to Total Rate Base;
- Data for the following years, at a minimum, must be provided:
    - Test Year = Prospective Rate Year;
    - Bridge Year = Current Year;
    - Three Most Recent Historical Years (or number of years necessary to provide actuals back to and including the most recent Board Approved Test Year, but not less than three years);
    - Most recent Board Approved Test Year.
- A statement is to be provided as to when the forecast was prepared and when it was approved by utility management and/or Board of Directors for use in the application;
- Multi-year data for each of the above-referenced years is to be presented on the same sheet for the summary/main schedules;
- A detailed year-over-year variance analysis is to be provided between the Test Year and Bridge Year, the Historical Year(s) and the last Board Approved Test Year, including reasons/drivers of variances and the contribution of each driver towards the total year-over-year variance;
- Calculations of revenue sufficiency/deficiency;
- For Board-prescribed values such as ROE and deemed debt rates, the most recent values available from the Board are to be used with an accompanying statement that they will be updated as required. If a distributor is proposing to use values and methodologies other than those prescribed by the Board, this proposal should be clearly stated and reasons/supporting evidence provided;
- The most recent Board-approved RPP and an estimate for non-RPP (at the time of filing) is to be used for the electricity commodity price;
- Changes to accounting policies made since the applicant's last cost of service filing are to be identified and a summary of the impacts of any such changes is to be provided (these include any changes on adoption of IFRS effective January 1, 2011);
- Changes in legal organization or control must be identified;
- Changes in tax status (for example, a change from a corporation to a limited partnership) must be disclosed;
- Any orders or directions outstanding from previous Board Decisions or Orders are to be identified and addressed.

2.1.3 Confidential Information

The Board relies on full and complete disclosure of all relevant information in order to ensure that its decisions are well-informed. The Board recognizes that applicants may consider some of that information to be confidential and may wish to request that it be protected. In such cases, the relevant rules in the Board's *Rules of Practice and Procedur*e and the procedures set out in the Board's *Practice Direction on Confidential Filings* are to be followed by all participants in a proceeding before the Board, unless otherwise directed by the Board.

The onus is on the applicant or entity requesting confidential treatment to demonstrate to the satisfaction of the Board that confidential treatment is warranted. It is the Board's expectation that parties will make every effort to limit the scope of their confidentiality requests to an extent commensurate with the commercial sensitivity of the information at issue or with any legislative obligations of confidentiality or non-disclosure. The applicant or entity making such a request must prepare meaningful redacted documents or summaries so as to maximize the information that is available on the public record. This will provide all interested parties with a fair opportunity to present their cases and will permit the Board to provide meaningful and well-documented reasons for its decisions.

2.1.4 Green Energy Act Requirements

Distributors should incorporate a separate section in their applications providing an overview of any proposals with respect to renewable generation connection plans, or smart grid plans that will have an impact on the application. This overview should summarize the key elements of any proposals made and their impacts on the application. These key impacts should also be broken out separately from the remaining costs in the relevant sections of the application (e.g. OM&A impacts arising from the green energy plans should be identified separately from the remaining OM&A costs, as discussed subsequently).

Distributors should consult the following documents with respect to requirements arising from amendments to the OEB Act made by the *Green Energy and Green Economy Act, 2009* and related Board initiatives that may affect their 2011 cost of service applications:

Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence (EB-2009-0397)

On March 25, 2010, the Board issued its "Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence" which are available on the Board's website. It is a deemed condition of licence of all distributors that they file, at the time and in the manner mandated by the Board, distribution system plans relating to the connection of renewable generation and the development of a smart grid. Distributors are not required to file such a plan with their 2011 applications, but will be required to do so in their cost of service rate applications for 2012 and subsequent rate years. If a distributor chooses to file such a plan in its cost of service application for 2011 rates, it will also need to follow the Filing Requirements.

Applicants that are filing "Green Energy Plans" to address renewable generation connection or smart grid development in accordance with the Filing Requirements should file specific Capital Expenditure and Operations & Maintenance cost details in sections 2.3.5 and 2.5 respectively.

Distribution System Code Amendments (EB-2009-0077)

On October 21, 2009, the Board issued amendments to the Distribution System Code which revised the Board's approach to assigning cost responsibility between distributors and generators in relation to the connection of renewable generation facilities.

Report of the Board Re: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario (EB-2009-0152)

The regulatory framework set out in this Report builds on the Board's rate-making framework by augmenting "conventional" cost recovery mechanisms with a range of "alternative" cost recovery mechanisms designed to facilitate appropriate infrastructure investment by distributors and transmitters.

Board Report: Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09 (EB-2009-0349)

Section 79.1 of the OEB Act provides for rate protection for customers of a distributor that incurs costs to make an eligible investment for the connection of qualifying generation facilities. The Board issued a Report that sets out a framework for the Board's approach to the determination of the "direct benefits" that accrue to those customers as a result of all or part of the eligible investment made or planned to be made by the distributor. This will represent the allocation of eligible investment costs to the distributor's ratepayers, with the remaining costs allocated to provincial ratepayers.

If the applicant is proposing that the cost of a renewable generation connection investment be recovered from all Ontario ratepayers, as per section 79.1 of the OEB Act, the applicant should provide a calculation of the direct benefits accruing to the distributor's customers for the test year, consistent with the Board 's Report, as well as the remaining allocation pertaining to these eligible investment costs to be recovered from provincial ratepayers.

Decision and Order with Respect to a MicroFIT Generator Rate (EB-2009-0326)

Ontario's Feed-In Tariff ("FIT") program is expressly contemplated in the *Electricity Act, 1998* and administered by the Ontario Power Authority. The program includes a stream called "microFIT", which is designed to encourage homeowners, businesses and others to generate renewable energy with projects of 10 kilowatts ("kW") or less. In its Decision and Order issued February 23, 2010, the Board established a service classification for microFit Generation accounts, which is to be used by all licensed distributors.

In addition, the Board approved a single province-wide rate to be applied by all distributors. Specifically, on March 17, 2010, the Board issued its Rate Order which stated that the province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator rate class was approved at $5.25 per month, effective September 21, 2009. Distributors should include revenue arising from this charge as "Other Revenue" in their applications.

Guidelines: Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities (G-2009-0300)

These Guidelines describe the ownership scenarios available in relation to the ownership of generation and energy storage facilities described in section 71(3) of the OEB Act ("qualifying facilities") and set out the regulatory and accounting requirements applicable to each scenario.

Qualifying facilities may be owned directly by a distributor, or may be owned by an affiliate of the distributor. Under the affiliate ownership scenario, a distributor would need only to review its policies, procedures and processes to ensure compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters.

The ownership and operation of qualifying facilities is not a rate-regulated activity. Accordingly, if a distributor chooses to own and operate a qualifying facility directly as part of its business, costs would not be recovered through rates and a regulatory return would not be earned on the investment. For rate setting purposes, the distributor would need to file financial information in rate applications that clearly delineates the distributor's regulated activities from its non-rate related activities, as outlined in the Guidelines. For greater clarity, the distributor would need to file financial information for the consolidated utility, and individual statements for rate regulated activities and non-rate regulated activities on a pro-forma basis for the test period.

2.1.5 Transition to IFRS

IFRS reporting standards become effective on January 1, 2011. Distributors should apply the guidance provided in Chapters 7-9 of the *Report of the Board, Transition to International Financial Reporting Standards*, (EB-2008-0408) regarding the choice of basis for accounting upon which to present their application (Canadian Generally Accepted Accounting Principles versus IFRS). Transmitters may also choose to apply the guidance provided in the Report.

2.2 Exhibit 1. Administrative Documents

The administrative documents identified in this section provide the background and summary to the case as filed. Administrative documents consist of four sections: 1) Administration; 2) an overview of the filing; 3) the background financial information of the applicant; and 4) materiality thresholds. The requirements for each are provided below.

2.2.1 Administration

- Table of Contents;
- Application;
- Contact information;
- List of specific approvals requested;
- Proposed Issues List;
- Accounting Orders and List of non-compliant items with the Uniform System of Accounts including references to Accounting Orders;
- Description of applicant's operating environment:
  - General description and map showing where the utility operates within the province, and the communities serviced by the utility. A utility may provide more detailed geographic and/or engineering maps where these may be useful to understand parts of the application, such as a capital expansion or replacement program;
  - A list of any neighbouring utilities;
  - A description of whether the utility is a host utility (i.e. transmitting electricity to another distributor's network at distribution-level voltages) and/or an embedded distributor (i.e. receiving electricity at distribution-level voltages from any host distributor). The utility should identify the host or embedded distributor(s). Partially embedded status should also be clearly identified.
- Corporate and Utility Organizational Structure:
  - High-level utility organization chart, showing the main units and executive and senior management positions within the utility;
  - Corporate Entities Relationship Chart, showing:
    - the organization of any associated or affiliated entities with respect to each other;
    - the extent to which the parent company is represented on the utility company board;
    - the reporting relationships between utility management and parent company officials;
    - the services and the nature of the services provided to/by entities; and,
    - any shared services among the entities.
  - Planned changes in corporate or operational structure.

- Identification of Board Directives from any previous Board Decisions and/or Orders. The applicant should clearly indicate how these are being addressed in the current application (e.g. filing of a study as directed in a previous Decision);
- List of Witnesses and their Curriculum Vitae.

2.2.2 Overview

- Summary of Application (purpose, need and timing of the application and typical customer impact by customer class);
- Budget Overview (Capital & Operating):
    - Budget directives and guidelines;
    - Economic assumptions used.
- Changes in methodology from previous applications or established Board practice or policy (e.g. accounting, normalization, etc.);
- Schedule of overall revenue sufficiency/deficiency;
- Revenue Requirement Work Form. Please use the link on the Board's website to access this work form.

2.2.3 Financial Information

- Audited non-consolidated Financial Statements ("Audited Financial Statements") of the utility for which the application has been made, covering the two most recent historical years. If the statements are not available at the time of filing, they must be provided as soon as they are available.
- *Pro Forma* Financial Statements for the Bridge and Test Years.
- The utility must file a detailed reconciliation of the financial results shown in the Annual Reports/Audited Financial Statements with the regulatory financial results filed in the application in order to separate non-utility business and to validate the regulatory financial results filed in the application.
- Annual report and Management's discussion and analysis, for the most recent year, of the parent company and all subsidiaries of the applicant.
- Rating Agency Report(s), if available.
- Prospectuses, information circulars, etc./ for recent and planned issuances.

2.2.4 Materiality Thresholds

The applicant must provide justification for changes from year to year to its rate base, capital expenditures, OM&A and other items above a materiality threshold. The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement.

These materiality thresholds are outlined in the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* of September 17, 2008 (EB-2007-0673) and are reproduced below

Unless a different threshold is referenced in a specific section of these Filing Requirements, the default materiality thresholds are:

- $50,000 for distributors with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million; and,
- $1 million for distributors with a distribution revenue requirement of more than $200 million.

If an applicant believes that an alternative threshold would be appropriate to its specific circumstances, it is free to propose such an alternative, with appropriate justification, in its application.

2.3 Exhibit 2. Rate Base

This exhibit includes information on Rate Base, Capital Expenditures, and Service Quality and Reliability Performance.

2.3.1 Overview

For rate base, the applicant must include the opening and closing balances, and the average of the opening and closing balances for gross assets and accumulated depreciation. Rate base shall also include an allowance for working capital.

At a minimum, the filed material in support of the requested rate base must include data for the Historical Actuals, Bridge (actuals to date, balance of year as budgeted), and Test Year.

Continuity statements and year-over-year variance analyses must be provided.

Continuity statements must provide year-end balances and include interest during construction, and all overheads.

Variance analyses must provide a written explanation for rate base-related material when there is a variance greater than the applicable materiality threshold.

The following comparisons must be provided:

- Historical Board-approved vs. Historical Actual (for most recent historic Board-approved year);
- Historical Actual vs. preceding Historical Actual (for the relevant number of years);
- Historical Actual vs. Bridge; and
- Bridge vs. Test Year.

The information outlined in Appendix 2-B should be provided for each year.

2.3.2 Gross Assets – Property Plant and Equipment

The applicant must provide the following information:

- Breakdown by function (transmission plant, distribution plant, general plant, other plant) for required statements and analysis;
- Detailed breakdown by major plant account for each functionalized plant item. For the Test year, each plant item should be accompanied by a written description;
- If the applicant received approval for an incremental capital module adjustment as part of a previous 3rd generation IRM application, this should be noted and a summary of what was approved and spent must be provided.

2.3.3 Accumulated Depreciation

Continuity statements should be reconcilable to the calculated depreciation expenses (under Operating Expenses) and presented by asset account.

2.3.4 Allowance for Working Capital

The applicant may take two approaches to calculation of its allowance for working capital; (1) the 15% allowance approach, or (2) filing of a lead/lag study.

15% Allowance Approach

The applicant should provide this calculation in table format showing all accounts and amounts included in the controllable expenses component as well as the cost of power and all individual rates and purchase levels used in its calculation. Cost of power rate estimates (i.e. RPP and non-RPP and transmission rates) should be identified.

2.3.5 Capital Expenditures

The following capital expenditure information should be provided by the applicant on a project specific basis:

- Overall summary of capital expenditures over the past five historical years, the bridge year and the test year, showing capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress (CWIP). The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.
(One suggested format for filing this material is in Appendix 2-A.);

- Need, scope, purpose of project, related customer attachments, volumes and capital costs for projects over the applicable materiality threshold, as well as any applicable cost-benefit analysis;
- Detailed breakdown of starting dates and in-service dates for each project;
- Drivers of capital expenditure increases for the Test year;
- Where a proposed project requires leave to construct approval under Section 92 of the OEB Act, with construction commencement in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in section 4.3, section 4.4 and Chapter 5 of these Filing Requirements;
- Components of Other Capital Expenditures. (Reconcile all capital components to Total Capital Budget);
- Written explanation of variances;
- Capitalization policy and any proposed changes to that policy;
- The proposed accounting treatment, including the treatment of cost of funds for capital projects that have a project life cycle greater than one year;
- Any capital expenditures planned to address Renewable Generation Connection or Smart Grid development as per the Green Energy Act and the Board's EB-2009-0397 Filing Requirements of March 25, 2010 should be outlined including a proposal, where applicable, to divide the costs of renewable generation between the applicant's ratepayers and all Ontario ratepayers as per Regulation 330/09 as per Board's EB-2009-0349 (Determination of Direct Benefits) proceeding.

2.3.6 Asset Management Plan

- The applicant must provide a formal asset management plan; if the applicant has such a plan. If not, an explanation as to why the applicant does not have such a plan must be provided. The applicant must also state whether or not it is planning to have one in place in the future.
- In the absence of an asset management plan, the applicant must provide information outlining its approach to the planning and prioritization of capital projects.
- The applicant must also provide, at minimum, a three year forecast of capital expenditures (Test year plus two subsequent years).
- The applicant must also state whether or not it has undertaken any asset condition studies and, if so, copies of such studies must be filed.

2.3.7 Service Quality and Reliability Performance

The applicant must provide the following information:

- Reported Service Quality Indicators (SQIs), for the last three historical years. In the event performance is below the established standard, the applicant must provide an explanation for the under-performance, as well as actions taken to address this matter, and any outcomes, as appropriate.
- SAIDI, SAIFI and CAIDI, for the last three historical years. Reliability

performance should be reported for the three indicators for (1) All interruptions, and (2) All interruptions excluding Loss of Supply (Cause Code 2). In the event performance is outside of the established standard, the applicant must provide an explanation for the under-performance, actions taken to address the issue, and any outcomes, as applicable.

- Reference documents for service quality and reliability indicators can be found at the following links:

  Service Quality Indicators: Distribution System Code, Chapter 7
  http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/Distribution_System_Code.pdf
  Reliability Indicators: Reporting and Record Keeping Requirements dated May 1, 2010 pages 9-12:
  http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/RRR_Electricity.pdf

2.4 Exhibit 3. Operating Revenue

The applicant must provide its volume and revenue forecast, weather normalization methodology, and other sources of revenue in this exhibit. The applicant must include a detailed description of the methodologies and the assumptions used. The information presented must include:

1) Load and Revenue Forecasts;
2) Variance Analysis;
3) Other Revenue.

Estimates must be presented excluding commodity revenues.

If normalization is employed, then all data must be presented in the normalized form.

2.4.1 Load and Revenue Forecasts

Overview

The applicant must provide an explanation of the causes, assumptions and adjustments for the volume forecast. All economic assumptions and sources used in the preparation of the load and customer count forecast should be included in this section (e.g. Housing Outlook & Forecasts, relative energy prices and other variables used in forecasting volumes).

The applicant must also provide an explanation of the weather normalization methodology and its application. The Board recognizes that an important aspect of any case is the uniqueness of the transmitter or distributor and the circumstances in which it operates. Generic load profiles and universal normalization methods may not reflect the unique customer mix, weather, and economies of each utility's market. Two types of load forecasting models have generally been filed with the Board in previous cost of service applications. These are Multivariate Regression and Normalized Average use per Customer (NAC) models. While the applicant is not restricted to filing one of these two models, the following information is required for these two models when used. In the case where the applicant wishes to file a model other than the two noted above, the type of information that is required by the Board is provided below.

Multivariate Regression Model

- Rationale as to why the proposed model was chosen.
- Statistics of the regression equation(s) (coefficient estimates and associated t-statistics, and model statistics such as R^2, adjusted R^2, F-statistic, or Root-Mean-Squared-Error, etc.) Explanation for any resulting unintuitive relationships (e.g. negative correlation between load growth and economic growth, load growth and customer growth, etc.) Explanation of modelling approaches and alternative models tested would be beneficial, if available.
- Explanation of the weather normalization methodology proposed including:
  - If the monthly Heating Degree Days (HDD) and/or Cooling Degree Days (CDD) are used to determine normal weather, provide the monthly HDD and CDD based on a)10-year average and b) a trend based on 20-year.
  - In addition to the proposed Test year load forecast, provide load forecasts based on a) 10-year average and b) 20-year trend HDD and CDD.
  - Provide the rationale as to why the proposed normal weather methodology was chosen.

NAC Model

- Rationale as to why the proposed NAC methodology was chosen;
- Data supporting the calculation of NAC values used in the application for each rate class.
- Discussion of weather normalization considerations.

General Requirements

- Information demonstrating the historical accuracy of the load forecast for at least the past 5 years;
- Schedule of volumes (in kWh *and* in kW for those rate classes that use this charge determinant), revenues, customer count by rate class and total system load in kWh) for:
  - Historical Actual for the past 5 years;
  - Historical Board Approved;
  - Historical Actual for the past 5 years – weather normalized;
  - Bridge Year;
  - Bridge Year – weather normalized;
  - Test Year.

2.4.2 Variance Analysis

The applicant must provide the following variance analyses and relevant discussion:

- Historical Board-approved vs. Historical Actual;
- Historical Board-approved vs. Historical Actual – weather normalized;
- Historical Actual – weather-normalized vs. preceding year's Historical Actual – weather-normalized (for the necessary number of years);
- Historical Actual - weather normalized vs. Bridge Year – weather-normalized; and
- Bridge Year – weather-normalized vs. Test Year.

For each rate class, the applicant must provide the following information:

- Weather-normalized (if applicable) average historical actual consumption per customer for historical 5 years and forecasted average consumption for the Bridge Year and Test Year.
- For each rate class, an explanation of the net change in average consumption from last Board Approved and actual for Historical, Bridge Year and Test Year.
- Customer count increases or decreases forecasted for the Test Year with explanations of the forecast by rate class and identification as to whether customer count is shown in year-end or year average format.
- Details for the development of the billing kW value.
- Revenues, provided on the basis of both existing and proposed rates.

All data used to determine the forecasts should be presented and filed in live MS Excel spreadsheet format.

3. Other Revenue

The applicant must provide the following information on Other Revenue:

- Breakdown of each of the other distribution revenue accounts, see Appendix 2-C for the format;
- Comparison of actual revenues for historical years to forecast revenue for Bridge and Test Years;
- Detailed calculations of rate of return on non-core delivery activities, if they exist;
- Any new proposed specific service charges or new rules for applying existing specific service charges.

Revenues or costs (including interest) associated with deferral accounts, variance accounts and regulatory assets should not be included in Other Revenue.

2.5 Exhibit 4. Operating Costs

This exhibit must include information that summarizes the Operating, Maintenance and Administrative Costs and Taxes.

This exhibit should include the following sections:

1. Manager's Summary;
2. Summary and Cost Driver Tables;
3. Variance Analyses;
4. Employee Compensation Breakdown;
5. Shared Services/Corporate Cost Allocation;
6. Purchase of Non-Affiliate Services;
7. Depreciation/Amortization/Depletion;
8. Taxes/PILs;
9. Green Energy Plan OM&A Costs, if applicable; and
10. CDM Costs, if applicable.

The accounts listed in Appendix 2-D are to be included in the OM&A analyses.

2.5.1 Manager's Summary

The manager's summary should provide a brief explanation (quantitative and qualitative) of the following:

- OM&A Test Year Levels;
- Associated cost drivers and significant changes that have occurred;
- Overall trend in costs;
- Inflation rates used for general OM&A and Wages/Benefits. The applicant may use the GDP-IPI rate in effect at the time of the application, as a placeholder for an inflation rate accompanied by a statement that the rate will be updated at the time of the issuance of the Board's rate that will be effective in the Test Year. If the applicant proposes to use rates higher than the GDP-IPI rate determined by the Board, appropriate justification should be provided (such as studies and/or sources);
- Staffing levels;
- Drivers of wage and related increases;
- Business environment changes; and
- Materiality thresholds that apply and any other assumptions.

2.5.2 Summary and Cost Driver Tables

The applicant must include the following tables as part of their evidence:

- Summary of OM&A Expenses – Appendix 2-E;
- Detailed Account by Account OM&A Expenses – Appendix 2-F;

- OM&A Cost Drivers – Appendix 2-G;
- Regulatory Costs – Appendix 2-H; and
- OM&A Cost per Customer and per Full Time Equivalent – Appendix 2-I.

The applicant must note the specific requirements outlined below:

- One time costs;
- Regulatory costs;
- Low-income energy consumer programs (LEAP);
- Special Purpose Charges related to *the Green Energy and Green Economy Act, 2009* (Green Energy Act); and
- Charitable donations.

One-Time Costs

The applicant should identify one-time costs and provide an explanation as to how such costs are proposed to be recovered.

Regulatory Costs

The applicant must provide a breakdown of the actual and anticipated regulatory costs, including OEB cost assessments and expenses for the current application such as legal fees, consultant fees, costs awards, etc. In addition, the applicant must identify how such costs are to be recovered, e.g., whether the costs are proposed to be amortized and over what period. The amortization period would normally be the duration of the expected cost of service plus IRM term. If the applicant is proposing a different amortization period, it should explain why it believes this is appropriate.

Low-income Energy Assistance Programs (LEAP)

Pursuant to the Minister's September 8, 2009 letter to the Ontario Energy Board, an applicant should not include any costs in its cost of service rate application associated with LEAP other than costs that may be proposed to leverage existing programs such as Winter Warmth.

Special Purpose Charges ("SPC") related to the Green Energy and Green Economy Act, 2009 (Green Energy Act)

The Green Energy Act amends the *Ontario Energy Board Act, 1998* to allow for the assessment of special purpose charges related to expenses incurred and expenditures made by the Ministry of Energy and Infrastructure in respect of its energy conservation programs or renewable energy programs. On April 9, 2010, the Board issued a letter to all licensed Ontario electricity distributors setting out the amounts of the special purpose charges and instructions relating to payment of the assessment to the Ministry of Finance and to the recovery of the assessed amount from customers. The Board indicated that the amount that may be collected to recover the SPC assessment is not a rate, and it may be collected under the authority of the Act and the SPC Regulation. No rate order is required, and none will be issued.

On April 23, 2010, the Board issued a letter to all licensed Ontario electricity distributors notifying them of the establishment of a variance account 1521, Special Purpose Charge Assessment Variance Account, to track any difference between the amount remitted to the Minister of Finance and the amount recovered from customers. The OM&A account 5681, Special Purpose Charge Expense, established to track the expense and the revenue account 4324, Special Purpose Charge Recovery, should not be included in a cost of service application for distributor rate setting purposes. These accounts are classified as non-distribution. The timing of the variance account disposition should be in accordance with the requirements outlined in the SPC Regulation and the Board letter of April 23, 2010.

Charitable Donations

The applicant must file the amounts paid in charitable donations (per year) from the last Board approved rebasing application until (and including) the Test Year. The recovery of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to the distributor's customers in paying their electricity bills and assistance to low income consumers. If the applicant wishes to recover such contributions, it must provide detailed information for those claims. The applicant must review the amounts filed to ensure that all other non-recoverable contributions are identified, disclosed and removed.

2.5.3 Variance Analyses

The applicant must provide variance analyses, both quantitative and qualitative, for the comparisons outlined in Appendix 2-J.

2.5.4 Employee Compensation Breakdown

The applicant must complete Appendix 2-K in relation to employee complement, compensation, and benefits. In addition to the information required per the appendix, the status of pension funding and all assumptions used in the analysis should be provided.

Where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. This higher level of aggregation should be continued, if required, to ensure that no category contains three or fewer employees.

The applicant must provide details of employee benefit programs, including pensions and other costs charged to OM&A for the last Board-approved rebasing application, Historical, Bridge and Test Years. Post-retirement benefit cost accruals should be identified and described separately from current benefit costs. The most recent actuary report(s) should be included in the pre-filed evidence. What is disclosed in the tax section of the pre-filed evidence should agree with this analysis.

The applicant must provide:

- Explanations and justifications for year-over-year variances (include month hired for newly hired employees, inflation rates, collective agreement rates, etc);
- Basis for performance pay, goals, measures, and review processes; and
- Any relevant studies conducted by or for the applicant.

2.5.5 Shared Services/Corporate Cost Allocation

Shared Services is defined as the concentration of a company's resources performing like activities (typically spread across the organization) in order to service affiliates (and/or a parent company), with the intention of achieving lower costs and higher service levels.

Corporate Cost Allocation is an allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa). This is not to be confused with the allocation of the revenue requirement to rate classes for the purposes of rate design.

The applicant must provide the allocation methodology, a list of costs and allocators, and any 3rd party review of the methodology that was used.

The applicant must complete Appendix 2-L in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The table found in Appendix 2-L must be completed for each year. Additional rows may be added if required.

The table in Appendix 2-L requires the following information:

Type of Service Offered:

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company allocated to the applicant.

Pricing Methodology:

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant should also provide a description of why that pricing methodology was chosen and why it is appropriate.

Price for the Service:

The applicant must provide the amount the entity pays for the service that it receives.

Cost for the Service:

The applicant must provide the cost for the service.

% Allocation:

The applicant must provide the percentage of the costs allocated to the entity for the service being offered.

Variance analyses with explanation are required for the following:

- Test Year vs. Last Board-approved Rebasing Application; and
- Test Year vs. Most Current Actuals.

The applicant must identify any Board of Director-related costs for affiliates that are included in its costs.

2.5.6 Purchase of Non-Affiliate Services

Distribution expenses incurred through the purchase of services must be documented and justified.

The following items must be provided for Historical (actuals), Bridge and Test Years:
- Identity of each company transacting with the applicant subject to the applicable materiality threshold;
- Summary of the nature of the product or service that is the subject of the transaction;
- Annual dollar amount related to each company (by transaction); and
- A description of the specific methodology used in determining the vendor (including a summary of the tendering process/cost approach, etc.).

2.5.7 Depreciation/Amortization/Depletion

The information outlined below is required for Depreciation/Amortization/Depletion:

- The applicant must provide details for Depreciation, Amortization and Depletion by asset group for the Historical, Bridge and Test Years, including asset amount and rate of depreciation. This should tie back to the accumulated depreciation expense continuity schedule under Rate Base. The applicant should identify any Asset Retirement Obligations ("AROs") and any associated depreciation or

accretion expenses in relation to the AROs, including the basis and calculation of how these amounts were derived;
- The applicant must provide a statement as to whether it adheres to the Board's guidelines on amortization/depreciation rates (currently Appendix B of the *2006 Electricity Distribution Rate Handbook*, or as updated). If not, the applicant must summarize the differences, and indicate whether these have been previously reviewed and approved by the Board (if so, relevant references);
- In particular, the Board's general policy for electricity distribution rate setting is that capital additions would normally attract six months (i.e. half-year) of depreciation expense in the year that they enter service. The applicant should identify its historical practice and its proposal for the test year. Variances from this "half-year" rule must be documented with supporting rationale.
- Where the applicant is proposing new or changed depreciation/amortization rates, supporting documentation, preferably a depreciation study, must be provided;
- The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant should provide a written description of the depreciation practices followed and used in preparing the application.

Appendix 2-M should be completed.

2.5.8 Taxes (PILs, Capital Tax and Property Taxes)

The applicant must provide the information outlined below:

- Detailed calculations of PILs, or actual Provincial and Federal taxes, as applicable, including derivation of adjustments (e.g., Tax credits, CCA adjustments) for the Historical, Bridge and Test Years;
- Supporting schedules and calculations identifying reconciling items;
- Copies of most recent Federal and Provincial tax returns (non-utility tax items should be separated if material);
- Ontario Capital Tax for the historical and bridge years; and
- Calculation of tax credits (e.g., apprenticeship tax credits, education tax credits);
- Financial statements included with tax returns, if different from the financial statements filed in support of the application (section 2.2.3).

2.5.9 Green Energy Plan O&M Costs

Any Operations and Maintenance Costs to address Renewable Generation Connection or Smart Grid development as per the Green Energy Act and the Board's EB-2009-0397 Filing Requirements of March 25, 2010, should be outlined including a proposal, where applicable, to divide the costs of eligible renewable generation connection investments between the applicant's ratepayers and all Ontario ratepayers as per Regulation 330/09 and taking into account the Board's Report on the determination of direct benefits (EB-2009-0349).

2.5.10 CDM Costs

If a distributor has incurred CDM costs for Board-approved programs prior to December 31, 2010, the distributor may apply to the Board for recovery of the costs through distribution rates.

In accordance with the directive, dated March 31, 2010, from the Minister of Energy and Infrastructure, the Board is currently developing a CDM Code which will set out the obligations and requirements in relation to CDM activities after December 31, 2010. These Guidelines may be amended in future, if appropriate, following the adoption of the CDM Code.

2.6 Exhibit 5. Cost of Capital and Capital Structure

The Board's general guidelines for cost of capital in rate regulation is currently provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* (the 2009 Report), issued December 11, 2009. This report supersedes the previous *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the 2006 Report) of December 20, 2006..

If the applicant wishes to adopt the Board's guidelines for the cost of capital, the application should clearly state this and confirm that the cost of capital parameters will be updated in accordance with the Board's guidelines.

Alternatively, the applicant may apply for a utility-specific cost of capital and/or capital structure. If the applicant wishes to take such an approach, it must provide appropriate justification for its proposal.

2.6.1 Capital Structure

The elements of the deemed capital structure are shown below and must be presented with the required schedules for: current Board approved, Historical Actuals, Bridge and Test Years:

- Long-Term Debt;
- Short-Term Debt
- Preference Shares; and
- Common Equity.

Appendix 2-N must be completed for the required years.

An explanation of changes in actual capital structure is required including:

- Retirements of debt or preference shares and buy back of common shares; and
- Short-Term Debt, Long-Term Debt, preference shares and common share offerings.

2.6.2 Cost of Capital (Return on Equity and Cost of Debt)

These requirements are outlined in the 2009 Report. The applicant must provide the following information for each year:

- Calculation of cost for each capital component;
- Profit or loss on redemption of debt and/or preference shares, if applicable;
- Copies of any current promissory notes or other debt arrangements with affiliates;
- Forecasts of new debt anticipated in the bridge and test years, including estimates of the applicable rate and any pertinent information on each new debt instrument (e.g. whether the debt is affiliated or with a third party, expected term/maturity, any capital project(s) that the debt funding is for, etc.); and
- If the applicant is proposing any rate that is different from the Board guidelines, a justification of forecast costs by item, including key assumptions.

2.7 Exhibit 6. Calculation of Revenue Deficiency or Surplus

The applicant must include the following information in this exhibit, excluding energy costs and revenues:

- Determination of Net Utility Income;
- Statement of Rate Base;
- Actual Utility Return on Rate Base;
- Indicated Rate of Return;
- Requested Rate of Return;
- Deficiency or Sufficiency in Revenue; and
- Gross Deficiency or Sufficiency in Revenue.

The filing requirements have been designed in a manner to isolate the delivery-related sufficiency/deficiency separate and apart from the energy-related sufficiency/deficiency. In keeping with this separation, the applicant must provide revenue sufficiency or deficiency calculations net of electricity price differentials captured in the RSVAs and also net of any cost associated with LV charges or smart meter expenditures/revenues being tracked through variance accounts.

The applicant must provide a summary of the drivers of the test year sufficiency/deficiency, along with how much each driver contributes. Specific references to the data contained in the detailed schedules and tables should be provided so that parties can map the summary cost driver information to the evidence supporting it.

The impacts of any change in methodologies should be provided on the overall sufficiency/deficiency and on the individual cost drivers contributing to it.

2.8 Exhibit 7. Cost Allocation

This section outlines cost allocation requirements for distributors only. These requirements do not apply to transmitters.

The following areas are discussed in this section:

1. Cost Allocation Study Requirements;
2. Treatment of Transformer Ownership Allowance; and
3. Revenue to Cost ratios.

2.8.1 Cost Allocation Study Requirements

A completed cost allocation study using the Board approved methodology must be filed whether the applicant proposes to use it or not. This filing must reflect future loads and costs and be supported by appropriate explanations and live Excel spreadsheets.

If updated load profiles are not available, the load profiles of the classes may be the same as those used in the Informational Filing, scaled to match the load forecast as it relates to the respective rate classes (see section 2.4.2 above) . In particular, if a rate class has experienced a decline in customers or disappeared, or will disappear in the Test Year, the model must be consistent with the updated load forecast, and include an explanation of the changed load forecast of the rate class.

If the applicant determines that its 2006 cost allocation study (i.e. the Informational Filing) can be adapted to reflect future load and cost responsibility, it may use this model. However, the applicant must support this choice with information showing that there has been little change in the service territory and the nature of the distributor's business.

If the applicant is proposing to change its customer classification, the Informational Filing should not be used.

An applicant that is the host distributor to another distributor must include the embedded distributor(s) as a customer class in the cost allocation study. This is required even if the applicant proposes to bill the embedded distributor using its General Service class rates.

The Board recognizes that the applicant may not budget at the level of detail of the Uniform System of Accounts (USoA). However, to the extent possible, the applicant is required to summarize the forecast by USoA accounts together into defined functionalized costs in the cost allocation model for the purposes of cost allocation and comparative analysis.

The first table in Appendix 2-O is a format for showing the class revenue requirements, including a comparison with the Informational Filing or with a more recent study previously filed with the Board. In addition, if using the Board-issued model, the applicant should file a copy of input sheets I-6 and I-8, output sheets O-1 and O-2, and exhibit sheet E-4, or equivalent information if using another model.

2.8.2 Treatment of Transformer Ownership Allowance

The applicant will calculate distribution revenue from each customer class net of any transformer ownership allowance. In particular, if some customers in the GS>50 kW class provide their own transformers, revenue from the class should be calculated using the approved rate for the customers that the distributor provides with a transformer, and the approved rate less the transformer ownership allowance for those customers that provide their own transformer. The applicant should also ensure that transformer costs (Account 1850 and related accounts) are allocated to the classes in proportion to the load on the transformers supplied by the distributor (in the Board-issued model Sheet I8 - LTNCP).

If relying on the Informational Filing, the applicant should note that there were limitations in the cost allocation model distributed by the Board with respect to the treatment of the transformer ownership allowance. If using that model, the applicant must:

- Remove the “cost” associated with transformer ownership allowance from the revenue requirement (Worksheet I3);
- Subtract the “revenue” associated with the transformer ownership allowance from the approved revenue of the affected rates class(es) (worksheet I6, row 29); and,
- File Sheet O1 before and after removal of the transformer ownership allowance.

Appendix 2-O shows a format for reporting class revenues to enable a comparison between with the existing rate structure and the proposed rate structure.

2.8.3 Revenue-to-Cost Ratios

The Board expects that filings made by the applicant will follow the cost allocation policies reflected in the Board’s report of November 28, 2007, *Application of Cost Allocation for Electricity Distributors* (EB-2007-0667).

Rate re-balancing is the process of changing rates by different percentage amounts for different customer rate classes. To support a proposal to re-balance rates, the applicant must provide information on the revenue-to-cost ratios that would pertain if all rates were changed by a uniform percentage. These ratios must be compared with the ratios that will result from the rates being proposed by the applicant.

The applicant must file a table showing the revenue-to-cost ratios for each customer class in three scenarios:

- the previously-approved ratios most recently implemented by the applicant (Informational Filing for distributors that have filed only IRM2 applications);
- the ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, together with the updated cost allocation model; and
- the ratios that are proposed for the Test Year, which are the result of the proposed rates with the forecast of billing quantities, together with the updated cost allocation model.

If using a cost allocation model other than the Board model, the applicant must ensure that costs exclude LV and Smart Meter costs being recording in accounts 1555 and 1556, and that revenues exclude rate riders and rate adders.

If the applicant proposes to continue re-balancing after the Test Year, the ratios proposed for the subsequent year(s) should be provided. The final table in Appendix 2-O provides a format. In particular, if the proposed ratios are outside the Board's policy range in the Test year, the applicant must show the proposed ratios in subsequent years that would move the ratios into the policy range.

2.9 Exhibit 8. Rate Design

This section outlines rate design requirements for distributors only. These requirements for rate design do not apply to transmitters as their costs are combined with the other transmitters' costs to establish province-wide rates. Consequently, only allocated costs to rate classifications as required by the Board need be shown.

The following areas are discussed in this section:

1. Fixed/Variable Proportion
2. Retail Transmission Service Rates (RTSR)
3. Low Voltage Charges (where applicable)
4. Loss Adjustment Factors
5. Rate Schedules and Bill Impact Information

2.9.1 Fixed/Variable Proportion

The applicant must provide the following information related to the fixed/variable proportion of its proposed rates:

- Current fixed/variable proportion for each rate class, along with supporting information;
- Proposed fixed/variable proportion for each rate class, including an explanation for any changes from current proportions; and
- A table comparing current and proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study. The applicant must include an

explanation if the monthly fixed charge for any customer class exceeds the ceiling.

The fixed/variable analysis should be net of (i.e., exclude) funding adders and rate riders (i.e., smart meters, GEA, deferral/variance account disposition, etc.)

2.9.2 Retail Transmission Service Rates (RTSRs)

In preparing its application the applicant should reference the Board's Guideline: *Electricity Distribution Retail Transmission Service Rates*, Guideline G-2008-0001, October 22, 2008, and subsequent updates to the Uniform Transmission Rates.

The applicant must identify the RTSRs proposed for each class for the Test year and must provide the following related information:

- A table showing two years of wholesale network and connection costs and retail billings;
- An analysis of variances between costs and revenues and trends; and
- If the applicant is proposing revised rates, the applicant must identify how the uniform transmission rates (and/or the host distributor's RTSRs) are applied and must provide calculations used to derive the RTSRs.

2.9.3 Low Voltage Charges (where applicable)

The applicant must provide the following information related to its proposed Low Voltage (LV) rate adders:

- Proposed LV rate adders by customer class;
- A forecast of LV cost, which is the sum of the charge for Common Sub-Transmission (ST) lines, and facility charges such as connection to a shared LV distribution station; and
- Assumed volumes and LV rates.

2.9.4 Loss Adjustment Factors

The applicant must identify the proposed Supply facilities loss factor (SFLF), distribution and total loss factors for the Test year.

The applicant must file the following information related to its proposed loss factors:

- A statement as to whether the applicant is embedded;
- Details of loss studies and recommendations, if required by a previous decision;
- Calculations showing the losses in previous years. Five years of historical data is preferred. A minimum filing of three years of data is required;

- Appendix 2-P, which is a modified version of Schedule 10-5 from the *2006 Electricity Distribution Handbook*, showing the energy delivered to the distributor with and without losses;
- Explanation of distribution losses greater than 5%;
- Details of actions currently planned, and actions taken to reduce losses in previous five years and results if proposed distribution loss factor is greater than 5%; and
- Explanation of the derivation of the SFLF, including reasons for any differences from the standard SFLFs referenced in Appendix 2-P, Section H.

2.9.5 Rate Schedules and Bill Impacts

Appendix 2-Q must be filed. This appendix identifies existing rate schedules, the revenue deficiency recovery, a summary of proposed changes to rates, proposed volume and revenue recovery, and detailed bill impacts (including % change in distribution, % change in delivery and % change in total bill).

For proposed rate schedules, the following information should be provided:

- Proposed Rate and Revenue Adjustments;
- Detailed calculations of revenue per rate class under current rates and proposed rates by customer class;
- Detailed reconciliation of rate class revenue and other revenue to total revenue requirement (i.e., breakout volumes, rates and revenues by rate component, etc.); and
- Impact of changes on representative samples of end-users, i.e., volume, percentage rate change and revenue. Include the base distribution rates, any applicable rate adders or rate riders, and RTSRs. Commodity rates and regulatory charges should be held constant.

The applicant must provide an explanation of proposed changes to terms and conditions of service and the rationale behind those changes if the changes affect how the rates will be applied. The applicant should note that only rates shown on the Board-approved Tariff of Rates and Charges can be applied.

The applicant must provide the specific service charges proposed for the Test Year and must provide an explanation of any changes, deletions and additions.

The applicant should ensure that the information provided in this section is consistent with that provided in the working capital allowance calculation provided in Section 2.3, as it relates to rates such as RTSRs, or provide explanations for any differences.

2.10 Exhibit 9. Deferral and Variance Accounts

The following areas are discussed in this section:

1. Status of Deferral and Variance Accounts;
2. Disposition of Deferral and Variance Accounts; and,
3. Smart Meters.

2.10.1 Status of Deferral and Variance Accounts

The information outlined below is required regardless of whether or not the applicant is seeking disposition of any or all deferral and variance accounts:

- List of all outstanding deferral and variance accounts. The applicant must provide a brief description of any account that the applicant may have used differently than as described in the Accounting Procedures Handbook (APH);
- The continuity schedule for the period January 1, 2005 (or from the period following the last disposition) to present, showing separate itemization of opening balances, annual adjustments, accruals, interest and closing balances. A blank Excel spreadsheet reflecting these requirements will be made available on the Board's web site;
- Interest rates applied to calculate the carrying charges for each regulatory deferral and variance account. The applicant must provide the rates by month or by quarter for each year;
- Explanation if the continuity schedule differs from the trial balance reported through the Electricity Reporting and Record Keeping Requirements (RRRs).
- Identification of which of the above accounts the applicant will continue on a going forward basis; and
- Statement as to any new accounts the applicant is requesting and justification for these accounts.

2.10.2 Disposition of Deferral and Variance Accounts

The applicant must:

- Identify all accounts for which it is seeking disposition;
- Identify any accounts for which the applicant is not proposing disposition and the reasons why;
- Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year, or if the applicant is proposing a alternative period, an explanation should be provided.
- The principal balances proposed for disposition should be as of the last Audited Financial Statements.
- The applicant must show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period; and

- Establish separate rate riders to recover the RSVA Power, Sub-account Global Adjustment from non-RPP customers.

2.10.3 Smart Meters

If the applicant is applying for smart meter-related recoveries, the applicant should refer to Guideline G-2008-0002: *Smart Meter Funding and Cost Recovery*, or any successor document issued by the Board, with respect to:

- Any proposal for a change to the applicant's current Board-approved smart meter funding adder; or
- Any proposal to dispose of, or partially dispose of, balances in accounts 1555 and 1556.

In support of such proposals, the applicant must provide a continuity schedule of the sub-account balances in accounts 1555 and 1556 and complete the table contained in Appendix 2-R.

Appendix 2-A

Capital Projects Table

Tables in the format outlined below covering all relevant accounts should be submitted for the Test Year, Bridge Year and the relevant historic years:

Year: (Actual year, Bridge and Test Years)

USA Account #	Description	CCA Class	Project 1	Project 2	Project 3	Project 4	Etc…	**Total**
1805	Land							
1806	Land Rights							
1808	Land and Buildings							
1810	Leasehold Improvements							
1815	Transformer Station Equip. – Normally >50kV							
1820	Distribution Station Equip. – Normally <50kV							
…etc								
1995	Contributions and Grants - Credit							
Total								

Appendix 2-B

Fixed Asset Continuity Schedule

Fixed Asset Continuity Schedule

Year (1)

				Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land					$ -				$ -	$ -
47	1808	Buildings					$ -				$ -	$ -
13	1810	Leasehold Improvements					$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV					$ -				$ -	$ -
47	1820	Substation Equipment					$ -				$ -	$ -
47	1825	Storage Battery Equipment					$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures					$ -				$ -	$ -
47	1835	OH Conductors & Devices					$ -				$ -	$ -
47	1840	UG Conduit					$ -				$ -	$ -
47	1845	UG Conductors & Devices					$ -				$ -	$ -
47	1850	Line Transformers					$ -				$ -	$ -
47	1855	Services (OH & UG)					$ -				$ -	$ -
47	1860	Meters					$ -				$ -	$ -
47	1861	Smart Meters					$ -				$ -	$ -
47	1861	Smart Meters/Communication Systems					$ -				$ -	$ -
N/A	1905	Land					$ -				$ -	$ -
CEC	1906	Land Rights					$ -				$ -	$ -
47	1908	Buildings & Fixtures					$ -				$ -	$ -
13	1910	Leasehold Improvements					$ -				$ -	$ -
8	1915	Office Furniture & Equipment 10yr					$ -				$ -	$ -
8	1915	Office Furniture & Equipment 5yr					$ -				$ -	$ -
10	1920	Computer - Hardware					$ -				$ -	$ -
45	1921	Computer - Hardware post Mar 22/04					$ -				$ -	$ -
45.1	1921	Computer - Hardware post Mar 19/07					$ -				$ -	$ -
12	1925	Computer Software					$ -				$ -	$ -
10	1930	Transportation Equipment					$ -				$ -	$ -
8	1935	Stores Equipment					$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment					$ -				$ -	$ -
8	1945	Measurement & Testing Equipment					$ -				$ -	$ -
8	1950	Power operated Equipment					$ -				$ -	$ -
8	1955	Communications Equipment					$ -				$ -	$ -
8	1960	Graphics Equipment					$ -				$ -	$ -
47	1965	Water Heater Rental Units					$ -				$ -	$ -
47	1970	Load Management Controls					$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises					$ -				$ -	$ -
47	1980	System Supervisor Equipment					$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets					$ -				$ -	$ -
47	1995	Contributions & Grants					$ -				$ -	$ -
Etc.							$ -				$ -	$ -
		Total		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation
Transportation
Stores Equipment
Net Depreciation

(1) Provide a Fixed Asset Continuity Schedule for 5 historic Years, Bridge Year and Test Year

Appendix 2-B
Notes:

Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and the relevant historical years. At a minimum, the Applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2)at least three years of historical actuals, in addition to the Bridge and Test Year forecasts.

A Microsoft Excel version of this table is available, and the Applicant is requested to file the completed table for all applicable years in working Microsoft Excel format.

Applicants are requested to file copies of the completed Fixed Asset Continuity Schedules for all provided years.

The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

Appendix 2-C
Other Operating Revenue

Uniform System of Account #	Description	Actual Year	…	Bridge Year	Test Year
4235	Specific Service Charges				
4225	Late Payment Charges				
4082	Retail Services Revenues				
etc.					
Specific Service Charges					
Late Payment Charges					
Other Distribution Revenues					
Other Income and Expenses					
Total					

Specific Service Charges: Account 4235
Late Payment Charges: Account 4225
Other Distribution Revenues: Accounts 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses: Accounts 4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Account Breakdowns

- For each Other Distribution Revenue and Other Income and Expenses Account a detailed breakdown is required. (i.e. Interest and Dividend Income)

4405 – Interest and Dividend Income	Actual Year 1	Actual Year 2	Actual Year 3	Bridge Year	Test Year
Short-term Investment Interest					
Bank Deposit Interest					
Misc. Interest Revenue					
Etc….[1]					
Total					

[1] List and specify any other interest revenue

Appendix 2-D
Accounts for OM&A Analysis

Distribution Expenses – Operation

5005 Operation Supervision and Engineering
5010 Load Dispatching
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
5020 Overhead Distribution Lines and Feeders - Operation Labour
5025 Overhead Distribution Lines and Feeders - Operation Supplies and Expenses
5030 Overhead Sub-transmission Feeders - Operation
5035 Overhead Distribution Transformers- Operation
5040 Underground Distribution Lines and Feeders - Operation Labour
5045 Underground Distribution Lines and Feeders - Operation Supplies and Expenses
5050 Underground Sub-transmission Feeders - Operation
5055 Underground Distribution Transformers - Operation
5060 Street Lighting and Signal System Expense
5065 Meter Expense
5070 Customer Premises - Operation Labour
5075 Customer Premises - Materials and Expenses
5085 Miscellaneous Distribution Expense
5090 Underground Distribution Lines and Feeders - Rental Paid
5095 Overhead Distribution Lines and Feeders - Rental Paid
5096 Other Rent

Distribution Expenses – Maintenance

5105 Maintenance Supervision and Engineering
5110 Maintenance of Buildings and Fixtures - Distribution Stations
5112 Maintenance of Transformer Station Equipment
5114 Maintenance of Distribution Station Equipment
5120 Maintenance of Poles, Towers and Fixtures
5125 Maintenance of Overhead Conductors and Devices
5130 Maintenance of Overhead Services
5135 Overhead Distribution Lines and Feeders - Right of Way
5145 Maintenance of Underground Conduit
5150 Maintenance of Underground Conductors and Devices
5155 Maintenance of Underground Services
5160 Maintenance of Line Transformers
5165 Maintenance of Street Lighting and Signal Systems
5170 Sentinel Lights - Labour
5172 Sentinel Lights - Materials and Expenses
5175 Maintenance of Meters
5178 Customer Installations Expenses- Leased Property
5195 Maintenance of Other Installations on Customer Premises

Billing and Collecting

5305 Supervision
5310 Meter Reading Expense
5315 Customer Billing
5320 Collecting
5325 Collecting- Cash Over and Short
5330 Collection Charges
5335 Bad Debt Expense
5340 Miscellaneous Customer Accounts Expenses

Community Relations (including sales expenses)

5405 Supervision
5410 Community Relations - Sundry
5415 Energy Conservation
5420 Community Safety Program
5425 Miscellaneous Customer Service and Informational Expenses
5505 Supervision
5510 Demonstrating and Selling Expense
5515 Advertising Expense
5520 Miscellaneous Sales Expense

Administrative and General Expenses

5605 Executive Salaries and Expenses
5610 Management Salaries and Expenses
5615 General Administrative Salaries and Expenses
5620 Office Supplies and Expenses
5625 Administrative Expense Transferred–Credit
5630 Outside Services Employed
5635 Property Insurance
5640 Injuries and Damages
5645 Employee Pensions and Benefits
5650 Franchise Requirements
5655 Regulatory Expenses
5660 General Advertising Expenses
5665 Miscellaneous General Expenses
5670 Rent
5675 Maintenance of General Plant
5680 Electrical Safety Authority Fees
5685 Independent Electricity System Operator Fees and Penalties
5695 OM&A Contra Account
6205 Charitable Donations

Appendix 2-E
Summary of OM&A Expenses

Applicants should complete the two tables on this page.

Table 1 : OM&A Year over Year Comparisons

This table should be completed for each of the comparisons outlined below:[2]

1. Last Rebasing Year (LRY) Actuals versus LRY Board-approved (shown below)
2. Year 1 Actuals versus LRY Actuals
3. Year 2 Actuals versus Year 1 Actuals
4. Year 3 Actuals versus Year 2 Actuals
5. Bridge Year versus Year 3 Actuals
6. Test Year versus Bridge Year

These comparisons can be shown separately as below, or in one large table, but all the specified information must be provided:

	LRY (Board Approved)	LRY (Actuals)	Variance $	Variance %
Operations				
Maintenance				
Billing and Collecting				
Community Relations				
Administrative and General				
Total OM&A Expenses				
Inflation Rate				

Table 2: Additional Total OM&A Expense Comparative Information Table

Required Total OM&A Comparison	%
Test Year versus most current Actuals	
Test Year versus LRY Board approved	
Simple average of variance % for all actual years	
Compound annual growth rate for actual years	

[2] *If it has been more than three years since the applicant last filed a cost of service application, additional years of actuals should be incorporated as necessary so that complete actual information back to the last rebasing year is provided. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.*

Appendix 2-F[3]

Detailed, Account by Account, OM&A Expense Table[4] (excluding depreciation and amortization)

	Year 1 Actual	Year 2 Actual	Year 3 Actual	Bridge Year	Test Year
Operation					
USoA # 5005 USoA # 5010					
……					
Maintenance					
……					
Billing and Collecting					
……					
Community Relations					
……					
Administrative and General					
……					
Total OM&A Expenses					

3 *If it has been more than three years since the applicant last filed a cost of service application, additional years of actuals should be incorporated as necessary so that complete actual information back to the last rebasing year is provided. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.*

4 Note: All OM&A accounts are required to be included on this table.

Appendix 2-G
OM&A Cost Driver Table[5]

OM&A	Year 1 Actual (last Board Approved Rebasing Year)	Year 2 Actual	Year 3 Actual	Bridge Year	Test Year
Opening Balance					
Cost Driver #1					
Cost Driver #2					
Cost Driver #3					
Cost Driver #4					
Etc….					
Closing Balance*					

For each year, a detailed explanation is required for each cost driver and associated amount.

* The closing balance of year 1 becomes the opening balance of year 2 etc.

[5] *If it has been more than three years since the applicant last filed a cost of service application, additional years of actuals should be incorporated as necessary so that complete actual information back to the last rebasing year is provided. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.*

Appendix 2-H
Regulatory Cost Schedule

Regulatory Cost Category (A)	USoA Account (B)	USoA Account Balance (C)	Ongoing or One-time Cost? (2) (D)	Last Rebasing Year (E)	Last Year of Actuals (F)	Bridge Year (G)	% Change (H)=[(G)-(F)]/(F)	Test Year Forecast (I)	% Change (J)=[(I)-(G)]//(G)
1. OEB Annual Assessment									
2. OEB Hearing Assessments (applicant initiated)									
3. OEB Section 30 Costs (OEB initiated)									
4. Expert Witness cost for regulatory matters									
5. Legal costs for regulatory matters									
6. Consultants' costs for regulatory matters									
7. Operating expenses associated with staff resources allocated to regulatory matters									
8. Operating expenses associated with other resources allocated to regulatory matters (1)									
9. Other regulatory agency fees or assessments									
10. Any other costs for regulatory matters (please define)									
11. Intervenor Costs									
12. Sub-total - Ongoing Costs (3)									
13. Sub-total – One time costs (4)									
14. Total (5)									

Notes: *(1) Please identify the resources.(2) Where a category's costs include both one-time and on-going costs, the Applicant should provide a breakdown of the costs between one-time and on-going.(3) Sum of all on-going costs identified in rows 1 to 11 inclusive. (4) Sum of all one-time costs identified in rows 1 to 11 inclusive,(5) Sum of rows 12 and 13.*

Appendix 2-I[6]
OM&A Cost per Customer and FTEE

	Actual Year 1 (last Board Approved rebasing)	Actual Year 2*	Actual Year 3*	Bridge Year	Test Year
Number of Customers[7]					
Total OM&A from Schedule 2-G					
OM&A cost per Customer					
Number of FTEEs					
FTEEs/Customer					
OM&A cost per FTEE					

6 *If it has been more than three years since the applicant last filed a cost of service application, additional years of actuals should be incorporated as necessary so that complete actual information back to the last rebasing year is provided. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.*

7 The method of calculating the number of customers must be identified.

Appendix 2-J
Variance Analysis

Applicants are to provide the following variance analyses ($ difference and percentage change) in the format of the table below.

i. Test Year vs. Last Board-Approved Rebasing Application (Actuals); and,
ii. Test Year vs. Most Current Actuals.

			Variance ($)	**Percent Change (%)**
Operation				
USoA # 5005 USoA # 5010				
……				
Maintenance				
……				
Billing and Collecting				
……				
Community Relations				
……				
Administrative and General				
……				
Total OM&A Expenses				

Appendix 2-K
Employee Costs

	Last Rebasing Year	Historical Year (Bridge Year - 1)	Bridge Year	Test Year
Number of Employees (FTEs including Part-Time)				
Executive				
Management				
Non-Union				
Union				
Total				
Number of Part-Time Employees				
Executive				
Management				
Non-Union				
Union				
Total				
Total Salary and Wages				
Executive				
Management				
Non-Union				
Union				
Total				
Current Benefits				
Executive				
Management				
Non-Union				
Union				
Total				
Accrued Pension and Post-Retirement Benefits				
Executive				
Management				
Non-Union				
Union				
Total				
Total Benefits (Current + Accrued)				
Executive	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Total Compensation (Salary, Wages, & Benefits)				
Executive	$ -	$ -	$ -	$ -
Management	$ -	$ -	$ -	$ -
Non-Union	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Compensation - Average Yearly Base Wages				
Executive				
Management				
Non-Union				
Union				
Total				
Compensation - Average Yearly Overtime				
Executive				
Management				
Non-Union				
Union				
Total				
Compensation - Average Yearly Incentive Pay				
Executive				
Management				
Non-Union				
Union				
Total				
Compensation - Average Yearly Benefits				
Executive				
Management				
Non-Union				
Union				
Total				
Total Compensation	$ -	$ -	$ -	$ -
Total Compensation Charged to OM&A				
Total Compensation Capitalized	$ -	$ -	$ -	$ -

A Microsoft Excel version of this table is available, and the Applicant is requested to file the completed table in working Microsoft Excel format.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year:__________

Name of Company		Service Offered	Pricing Methodology	Price for the Service ($)	Cost for the Service ($)	% Allocation
From	To					

Appendix 2-M
Depreciation and Amortization Expense

Applicants must provide a breakdown of depreciation and amortization expense in the following format for all relevant accounts. Asset Retirement Obligations (ARO), depreciation and accretion expense should be disclosed separately consistent with the notes in the historical audited financial statements. A Microsoft Excel version of this table is available, and the Applicant is required to file the completed table for all applicable years in working Microsoft Excel format.

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + 0.5 x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1805	Land								
1808	Buildings								
1810	Leasehold Improvements								
1815	Transformer Station Equipment >50 kV								
1820	Substation Equipment								
1825	Storage Battery Equipment								
1830	Poles, Towers & Fixtures								
1835	OH Conductors & Devices								
1840	UG Conduit								
1845	UG Conductors & Devices								
1850	Line Transformers								
1855	Services (OH & UG)								
1860	Meters								
1861	Smart Meters								
1861	Smart Meters/Communication Systems								
1905	Land								
1906	Land Rights								
1908	Buildings & Fixtures								
1910	Leasehold Improvements								
1915	Office Furniture & Equipment 10yr								
1915	Office Furniture & Equipment 5yr								
1920	Computer - Hardware								
1921	Computer - Hardware post Mar 22/04								
1921	Computer - Hardware post Mar 19/07								
1925	Computer Software								
1930	Transportation Equipment								
1935	Stores Equipment								
1940	Tools, Shop & Garage Equipment								
1945	Measurement & Testing Equipment								
1950	Power operated Equipment								
1955	Communications Equipment								
1960	Graphics Equipment								
1965	Water Heater Rental Units								
1970	Load Management Controls								
1975	Load Management Controls Utility Premises								
1980	System Supervisor Equipment								
1985	Miscellaneous Fixed Assets								
1995	Contributions & Grants								
etc.									
	Total								

Notes:

(1) This adjusts for assets still on the books but which have been fully amortized or depreciated.
(2) Applicable for the standard Board policy of the "half-year" rule, that additions in the year attract a half-year depreciation expnese in the first year. Deviations from this standard practice must be supported in the application.

Appendix 2-N
Capitalization and Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$ -	0.00%	$ -

A Microsoft Excel version of this table is available, and the Applicant is requested to file the completed table for all applicable years in working Microsoft Excel format.

Appendix 2-O
Cost Allocation

Please state year of Previous Cost Allocation Study: 2006 Informational Filing OR: _______ and then complete the following four tables:

a) Allocated Cost

Classes	Cost Allocated in Previous Study	%	Cost Allocated in Test Year Study (Column 7A)	%
Residential				
GS < 50 kW				
GS > 50 (or 50<GS<x, if applicable)				
GS>x if applicable				
Large User (if appl)				
Streetlights				
Sentinel Lights				
USL				
Other class (if applicable)				
Embedded Distributor(s) -- if host distributor				
Total	Σ = Service Revenue Requirement	Σ = 100 %	Σ = Test Year Service Revenue Requirement	Σ = 100 %

Notes:

If Applicant has filed a cost allocation study more recently than the Informational filing (EB-2006-0247 or EB-2007-0001, -2 or -3), show which year is being used.

Column 1:

- *modify rate classes as necessary to match the Application*
- *host distributors: treat embedded distributor(s) as a separate class even if they are to be billed as General Service customers*

<u>*Columns 2 and 4:*</u>

- *If using Board-issued model, data source is Worksheet O-1, row 35*
- *Embedded Distributor: Service Revenue Requirement does not include Account 4750 – LV cost.*

<u>*Column 2:*</u>

- *If necessary, modify the Informational filing study by setting Transformer Ownership Allowance to $0 (worksheet I3, cell F15)*

<u>*Column 4:*</u>

- *Exclude costs recorded in deferral accounts*
- *Include Smart Meter costs only to the extent that they are being included in Rate Base and Revenue Requirement*
- *Do not include Transformer Ownership Allowance as a cost (If using Board-issued cost allocation model, enter zero on Worksheet O-3, cell F15, and ensure on Worksheet E-4, row 57 that the allocation of Account 1850 is based on LTNCP. (Line Transformer Non-coincident Peak load)*

b) Calculated Class Revenues

	Column 7B	**Column 7C**	**Column 7D**	**Column 7E**
Classes: (same as previous table)	**L.F. X current approved rates**	**L.F. X existing rates X (1 + d)**	**L.F. X proposed rates**	**Miscellaneous Revenue**
Residential				
GS < 50 kW				
GS > 50 kW				
GS>x if applicable				
Large User				
Streetlights				
Sentinel Lights				
USL				
Other class(es)				
Total	Σ = Revenue @ Current Approved Rates	Σ = Base Revenue Requirement	Σ = Base Revenue Requirement	Σ = Revenue Offset

Notes:

<u>*Columns 7B – 7D:*</u>

- *"L.F." means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, **<u>and</u>** kWh or kW)*
- *Exclude revenue from rate adders and rate riders (Embedded Distributors: exclude revenue in Account 4075*
- *For classes where some customers get a transformer ownership allowance, include revenue net of the allowance (i.e. for the volumetric component, "approved rate" X load of customers who receive transformer service from the distributor, **PLUS** "approved rate **less TOA"** X load of customers that supply their own transformer)*

<u>*Columns 7C and 7D:*</u>

- *Column total should equal the Base Revenue Requirement.*
- *Embedded Distributors: Base Revenue Requirement does not include Account 4750 – LV cost.*

<u>*Column 7C*</u>

- *calculate "d" as Revenue Deficiency / Base Revenue Requirement . (Revenue Deficiency* = "Base Revenue Requirement" minus "Revenue @ Current Approved Rates")

<u>*Column 7E*</u>

- *If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19*

c) Re-balancing Revenue-to-Cost Ratios

Class	**Previously Approved Ratios**	**Status Quo Ratios**	**Proposed Ratios**
	Most Recent Year: **20___**	= (Column 7C + column 7E) / (Column 7A)	= (Column 7D + Column 7E) / (Column 7A)
Residential			
GS < 50 kW			
GS > 50 kW			
GS>x if applicable			
Large User (if appl)			
Streetlights			
Sentinel Lights			
USL			
Other class (if applicable)			

Notes:

Previously Approved Revenue to Cost Ratio:

- *For most applicants, Most Recent Year would be the third year of the IRM3 period eg. if rebased in 2008 with further adjustments over 2 year, Most Recent Year is 2010,*
- *For applicants that have been adjusted by IRM2, year is "2006" and enter the ratios from the Informational Filing*

d) Proposed Revenue to Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2011	2012	2013	
	%	%	%	%
Residential				85 – 115
GS < 50 kW				80 – 120
GS > 50				80 – 180
GS>x if applicable				80 – 180
Large User (if appl)				85 – 115
Streetlights				70 – 120
Sentinel Lights				70 – 120
USL				80 - 120
Other class (if applicable)				

Appendix 2-P
Loss Factors

Modified Schedule 10-5: Determination of Loss Factors

		Year 1	Year 2	Year 3	Year 4	Year 5	5 Year Average
	Losses in Distributor's System						
A_1	"Wholesale" kWh delivered to distributor (higher value)						
A_2	"Wholesale" kWh delivered to distributor (lower value)						
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)						
C	Net "Wholesale" kWh delivered to distributor **(A_2)-(B)**						
D	"Retail" kWh delivered by distributor						
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)						
F	Net "Retail" kWh delivered by distributor **(D)-(E)**						
G	Loss Factor in distributor's system **[(C)/(F)]**						
	Losses Upstream of Distributor's System						
H	Supply Facility Loss Factor						
	Total Losses						
I	Total Loss Factor **[(G)x(H)]**						

Notes

A_1

- If directly connected to IESO controlled grid, kWh pertains to virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two kWh values provided by MV-WEB.
- If fully embedded within a host distributor, kWh pertains to virtual meter, on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One, kWh from the Hydro One invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided by the Hydro One invoice.
- If partially embedded, kWh pertains to the sum of above.

A_2

- If directly connected to the IESO controlled grid, kWh pertain to metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.
- If fully embedded within a host distributor, kWh pertains to actual/virtual meter at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One, kWh from the Hydro One invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided by the Hydro One invoice.
- If partially embedded, kWh pertains to sum of above.
- Additionally, kWh pertaining to distributed generation should be included in $\mathbf{A_2}$.

B

- If a Large Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1%, i.e. **B = 1.01 x E**.

D

- kWh corresponding to D should equal total of "total billed energy sales in kWhs for each rate class" in item 1 of Section 2.1.3 in *Electricity Reporting and Record Keeping Requirements* dated April 4, 2008.

G & I

- These loss factors pertain to secondary metered customers with demand less than 5,000 kW.

H

- If directly connected to IESO controlled grid, SFLF = 1.0045.
- If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface x loss factor re losses in host distributor's system. If host distributor is Hydro One, SFLF = 1.0060 x 1.0278 = 1.0340.
- If partially embedded, SFLF is weighted average of above.

Appendix 2-Q
Bill Impact Table[8]

Consumption	0	kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge			1	$ -		1	$ -	$ -	
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate			0	$ -		0	$ -	$ -	
Low Voltage Rate Adder			0	$ -		0	$ -	$ -	
Volumetric Rate Adder(s)			0	$ -		0	$ -	$ -	
Volumetric Rate Rider(s)			0	$ -		0	$ -	$ -	
Smart Meter Disposition Rider			0	$ -		0	$ -	$ -	
LRAM & SSM Rate Rider			0	$ -		0	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider			0	$ -		0	$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ -**			**$ -**	**$ -**	
RTSR - Network			0	$ -		0	$ -	$ -	
RTSR - Line and Transformation Connection			0	$ -		0	$ -	$ -	
Sub-Total B - Delivery (including Sub-Total A)				**$ -**			**$ -**	**$ -**	
Wholesale Market Service Charge (WMSC)			0	$ -		0	$ -	$ -	
Rural and Remote Rate Protection (RRRP)			0	$ -		0	$ -	$ -	
Special Purpose Charge			0	$ -		0	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)			0	$ -		0	$ -	$ -	
Energy			0	$ -		0	$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ -**			**$ -**	**$ -**	
HST		13%		$ -	13%		$ -	$ -	
Total Bill (including Sub-total B)				**$ -**			**$ -**	**$ -**	
Loss Factor (%)									

Utilities must provide bill impact for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

- Residential (kWh) – 100, 250, 500, 800, 1000, 1500, 2000
- GS<50kW (kWh) – 1000, 2000, 5000, 10000, 15000
- GS>50kW (kW) – 60, 100, 500, 1000
- Large User – range appropriate for utility
- Lighting Classes and USL – 150 kWh and 1 kW, range appropriate for utility

A Microsoft Excel version of this spreadsheet is available separately.

[8] The "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Appendix 2-R
Smart Meters

Irrespective of whether the distributor is actively deploying smart meters or not (exception: if the distributor has completed its smart meter deployment and has had accounts 1555 and 1556 reviewed and disposed of), the distributor should provide the following:

Year	Smart Meters Installed			Percentage of applicable customers converted (%)	Account 1555		Account 1556
	Residential	GS < 50 kW	Other[1]		Funding Adder Revenues Collected	Capital Expenditures	Operating Expenses
2006							
2007							
2008							
2009							
2010							
2011 (and beyond) (if required)							

1. The distributor should provide details of Other (e.g. Toronto Hydro has some legacy non-interval GS > 50 kW customers being converted to “smart” meters).

In addition, a distributor that is requesting an increase to its current approved smart meter funding adder (i.e. to $1.00 or another utility-specific amount), should provide the information required to support such request in accordance with section 1.4 of *Guideline G-2008-0002: Smart Meter Funding and Cost Recovery*.

Any request for disposition or partial disposition of balances in account 1555 and 1556 (seeking approval for actual and audited costs related to smart meters actually installed) should also comply with the requirements of Guideline G-2008-0002 or further information communicated by the Board.