Ontario Energy Board Commission de l'énergie de l'Ontario

Ontario Energy Board

Filing Requirements For
Electricity Distribution Rate Applications
- 2015 Edition for 2016 Rate Applications -

Chapter 2

Cost of Service

July 16, 2015

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

2.0 Introduction

On October 18, 2012, the OEB released its *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Report), which introduced three rate-setting methods: (1) 4th Generation IR (now called Price Cap IR), (2) Custom IR and (3) Annual IR Index. The Price Cap IR option consists of a cost of service ("CoS or rebasing)[1] followed by four years of incentive regulation mechanism (IRM) adjustments.

The RRFE Report emphasized the importance of good distribution system planning, including optimizing, prioritizing and pacing distributor's capital expenditures to control costs and promote rate predictability.

The OEB's determinations on electricity distribution applications are guided by the need to achieve outcomes that result in genuine benefits for customers. As such, distributors must ensure that their applications incorporate a long-term strategy for delivering services that meet the expectations of their customers.

Distributor applications should therefore establish strong incentives to deliver customer value and achieve sustainable efficiency improvements. Approval of a distributor's revenue requirement will consider a distributor's past and target performance against the four RRFE outcomes discussed in the RRFE Report.

Robust planning of investments is essential to maintaining and enhancing distributor networks in order to ensure that customers continue to receive safe and reliable services. The critical challenge facing the OEB in reviewing these programs is to ensure that the distributors' plans are aligned with the needs of customers, are appropriately paced and support the effective management of the assets.

Where the OEB determines that the information on a distributor's asset management and capital expenditure planning processes and related capital expenditure plan is inadequate to make a determination of just and reasonable rates, the OEB may refuse to consider the application pending the filing of additional information supporting the application.

[1] The OEB considers cost of service, CoS and rebasing to be the same and therefore these terms are used interchangeably.

This chapter relates to a cost of service rate application. Filing requirements for IRM rate applications (i.e. the Price Cap IR and Annual IR Index options) are provided in Chapter 3.

Distributors are rate regulated by the OEB on a stand-alone basis, which requires that the application must be prepared to show the regulated entity separately from its parent company or any other affiliates that are not regulated by the OEB. It is also important that only the amounts attributable to the distributor be reflected when determining matters such as the amount of tax recovery, debt costs and the cost of affiliate relationship transactions to be recoverable in rates paid by electricity ratepayers.

The filing requirements contained in this chapter and in Chapter 5 outline all the relevant information necessary for a complete cost of service application. The various appendices referenced in this chapter are linked to each of the sections in Chapter 2 and provide schedules to be completed by the applicant to facilitate the filing of all required information (e.g., Appendix 2-P Cost Allocation provides tables related to section 2.7.3 Revenue-to-cost Ratios). These appendices are available in Microsoft Excel format on the OEB's web site and must be completed by applicants and filed as part of a CoS application, including in live Microsoft Excel format.

The models issued by the OEB, including those contained in the appendices to this chapter, are provided to assist the applicant in filing a rate application, and to provide consistent formatting for all distributors for greater efficiency of the review process. An application to the OEB is the applicant's responsibility and the OEB expects that the application will be complete and accurate. Likewise, the applicant bears the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses in supporting its application. The applicant is responsible for advising the OEB of any concerns it may have regarding calculations flowing from the models as well as any changes that the applicant may have made to the models to address its own circumstances. Given the variety of different circumstances to be considered, the use of an OEB-issued model does not necessarily mean that the OEB will approve the results.

Applicants should review Chapter 1 of this document, which provides an overview of the OEB's expectations on certain generic matters, such as the completeness and accuracy of an application, the exploration of non-material items, and confidential filings.

2.0.1 Cost of Service Application in Advance of Scheduled Application

In the RRFE Report, the OEB outlined the transition plan which it had established to facilitate the adoption of the three new rate-setting methods. Distributors should consult Section 5.2 “Transition” of the RRFE Report to ensure that their applications are consistent with this transition plan.

Those distributors who are within the term of their current 3rd Generation IR (in other words are scheduled to rebase for January 1, 2016 rates or later) and are opting for the Price Cap IR option will continue to have their rates adjusted annually for the remaining years of their 3rd Generation IR term. Distributors can also opt for the Custom IR or the Annual IR Index methodologies. Distributors on annual Price Cap IR and planning to file a cost of service application earlier than scheduled must meet the threshold for early rebasing established in the OEB’s letter of April 20, 2010 .

2.0.2 Seeking Approval to Align Rate Year with Fiscal Year

Distributors may seek approval to align their rate year with their fiscal year (i.e. January 1). If a January 1 effective date for new rates is being requested, the OEB expects such applications to be filed no later than by the end of April of the year prior to the test year in order to allow sufficient time for the review and processing of the application.

2.0.3 General Requirements

The basic format of an application for a forward test year cost of service filing must include the following nine Exhibits:

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

These exhibits correspond with the standard elements of a cost of service application, which is intended to establish rates that recover a revenue requirement based on an estimate of demand for the test year. A schematic of the elements of a cost of service application is provided in the Chapter 2 Appendices, tab 3.

Other exhibits may also be included in an application to document other proposals for which the applicant is seeking OEB review and approval.

Applicants may refer to the Chapter 2 Appendices, tab 4 for a list of key references that underpin many of the filing requirements documented in this chapter.

The items outlined below are general requirements that are applicable throughout 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 (or the year immediately preceding the test year)
  - Three Most Recent Historical Years (or for as many years as are necessary to provide actuals back to and including the most recent OEB-Approved Test Year, but not less than three years)
  - Most recent OEB-Approved Test Year.
- Documents are to be provided in bookmarked and text-searchable Adobe PDF format.

If a distributor updates its evidence during the course of the proceeding, the distributor must adhere to Rule 11 of the *Rules of Practice and Procedure,* and the distributor must ensure that the following models, among others, are updated, as applicable, and the revised figures reconcile to each other:

- Revenue Requirement Work Form
- Chapter 2 Appendices
- EDDVAR Continuity Schedule
- Income Tax PILs Workform
- Cost Allocation Model
- RTSR Model
- Smart Meter Model.

2.0.3.1 Integrated Distribution Planning

On March 28, 2013, the OEB issued Chapter 5 of its Filing Requirements, *Consolidated Distribution System Plan Filing Requirements*.

Chapter 5 implements the OEB's policy direction on an integrated approach to distribution network planning, as set out in the RRFE Report, and applies to distributors filing distribution system plans, whether that filing is part of a cost of service application for the rebasing of rates under the Price Cap IR, a Custom IR application or a filing once every five years by a distributor on the Annual IR Index plan.

Good distributor planning is an essential prerequisite to the performance-based rate-setting approaches established under the RRFE Report, because it is necessary to ensure that the performance outcomes the OEB has established for electricity distributors are being achieved. A DSP must contain sufficient information to allow the OEB to assess whether and how a distributor has planned to deliver value to customers.

One of the primary goals of the DSP is pacing and prioritizing capital investments in a manner that considers rate impacts. The filing of a DSP can facilitate the achievement of this goal by focusing on the qualitative and quantitative information supporting investment proposals that will allow the OEB to assess how a distributor is seeking to control the costs and related rate impacts of proposed investments.

In addition, it is the OEB's expectation that the asset management plan underpinning the DSP should be directly linked to the proposed budget, in order to provide the OEB with robust evidence that the proposed capital expenditures have been through the necessary optimization and prioritization process.

The OEB will review the single test year application not just in the context of the projects and programs that are requested for the test year, but from the perspective of the distributor's plans for the subsequent four years until the next scheduled rebasing application. It is the OEB's expectation that, at a minimum, cost of service proceedings will consider the entire five year DSP as a means of assessing the distributor's planning and whether the test year requests are appropriately aligned with the DSP. While the OEB is not setting rates for years two through five of the five year Price Cap IR cycle, it will be approving test year applications based on the five year DSP plan, and the expectations established in the RRFE Report.

For distributor applications going forward, the OEB's *Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence* will no longer be applicable, and such investments will henceforth be reviewed by the OEB in the same fashion as other proposed capital expenditures. The funding mechanisms set out in that document, specifically for renewable generation connection and smart grid development, will no longer be available for expenditures proposed in cost of service applications to which Chapter 5 applies.

In addition, no new deferral accounts for these types of expenditures will be established, and existing deferral accounts are expected to be discontinued following the filing of the first cost of service application containing a consolidated distribution system plan. Distributors filing cost of service applications in 2014 and subsequent years must include proposals for disposition of any existing balances in the deferral accounts.

Distributors yet to file a cost of service application containing a consolidated DSP pursuant to Chapter 5 will continue to be able to record renewable energy generation costs, smart grid demonstration costs and funding adder revenues (for existing funding adders) in deferral accounts already established for this purpose. These distributors may also seek new funding adders for material eligible investments as part of their IRM applications, if they are on the Price Cap IR plan, until such time as the first cost of service application containing a consolidated DSP.

In addition, distributors that have included eligible investments to connect qualifying facilities in their DSPs filed in a cost of service application may seek OEB approval for investments forecast to enter service beyond the test year for purposes of implementing rate protection pursuant to the legislation. For these future years' investments, distributors shall recover only the component associated with rate protection. The remaining component of each investment is treated as any other capital investment made in non-rebasing years.

If eligible investments, as defined under O.Reg. 330/09 under the OEB Act, are approved by the OEB, variance accounts will continue to be used for the purpose of recording actual costs of approved eligible investments, and revenue received from the IESO pursuant to the provincial pooling mechanism set out in section 79.1 of the OEB Act.

Further information on the requirements to implement recovery from all Ontario ratepayers can be found in section 2.2.2.5.

2.0.4 Accounting Standards

This section provides information on International Financial Reporting Standards (IFRS) and Canadian Generally Accepted Accounting Principles (CGAAP) accounting standards relevant to the filing of 2016 cost of service applications.

The accounting standard that is used in each of the historical, bridge and test years must be clearly stated. The applicant must provide a summary of changes to its accounting policies made since the applicant's last cost of service filing (e.g. capitalization of overhead, capitalization of interest, depreciation, etc.). Revenue requirement impacts of any changes in accounting policies must be separately quantified. A completed Appendix 2-Y must be filed.

The OEB notes that utilities must convert to IFRS as of January 1, 2015, unless they adopt United States Generally Accepted Accounting Principles (USGAAP) or Accounting Standards for Private Enterprises (ASPE). Applications filed using CGAAP after December 31, 2014 will no longer be accepted.

2.0.4.1 Modified IFRS Application

Distributors should refer to the following documents for detailed guidance relating to the use of IFRS in application filings:

- *Report of the Board: Transition to IFRS;* dated July 28, 2009;
- *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment (*the "Addendum"), dated June 13, 2011;
- *Asset Depreciation Study for the Ontario Energy Board*, Kinectrics Inc. ("Kinetrics Report") for distributors sponsored by the Board dated July 8, 2010;
- Regulatory Accounting Policy Direction Regarding Changes to Depreciation Expense and Capitalization Policies in 2012 and 2013, dated July 17, 2012; and
- Accounting Policy Changes for Accounts 1575 and 1576, dated June 25, 2013.

In February 2013, the Accounting Standards Board decided to extend the deferral of the mandatory adoption of IFRS for Canadian utilities with qualifying rate-regulated activities for financial reporting purposes to January 1, 2015. January 1, 2015 is the mandatory year of adoption for IFRS, therefore, all applicants are expected to file for the test year on the basis of modified IFRS (MIFRS), whether they have already adopted IFRS for financial reporting purposes or will adopt IFRS for financial reporting purposes effective January 1, 2015. For most distributors filing for 2015 or later rates, 2015 will be the year of adoption of IFRS.

Other than impacts flowing from changes to depreciation and capitalization, the applicant must identify all material changes in the adoption of IFRS (e.g. pensions and post-employment benefits) that impact its application. The impact should be quantified and an explanation and details of the changes should be provided. If no material changes were identified upon the adoption of IFRS that impact the application, the applicant should provide a statement indicating this and confirming that it has considered all possible impacts.

For the historical years, evidence in the application may be presented using CGAAP as applicants are to present the information in the application using the same accounting standard used for financial reporting purposes in each particular year. In the transition year (i.e. the year prior to adoption of IFRS), the applicable detailed information should be presented in both MIFRS and CGAAP, if the total changes from the change in accounting standards are material. If the changes from the accounting standards are not material, the applicant should indicate the total dollar value of the change and explain why the change was not material.

2.0.4.2 Changes to Depreciation and Capitalization Policies

Per the OEB's letter of July 17, 2012 referenced above, distributors electing to remain on CGAAP in 2012 were required to implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes were mandatory in 2013 for all distributors that had not yet made these changes, and therefore, all applications for 2016 rates should reflect that these changes were made in 2012 or 2013. In the year that these accounting policy changes were implemented, two sets of the applicable information must be presented to show the accounting policy changes. Each set of information must include the property plant and equipment (PP&E) and depreciation schedules.

2.0.5 Scorecard Performance Evaluation

Under the Renewed Regulatory Framework a distributor is expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services. To facilitate performance monitoring and benchmarking of distributors the OEB started using a Scorecard approach in 2013.

On March 5, 2014, the OEB issued its *Report of the Board on Performance Measures for Electricity Distributors: A Scorecard Approach* which sets out the OEB's policies on the measures that will be used by the OEB to assess a distributor's effectiveness and continuous improvement in achieving the four outcomes of customer focus, operational effectiveness, public policy responsiveness and financial performance to the benefit of existing and future customers. The form and implementation of the OEB's performance monitoring tool – the Scorecard – is also addressed in the report.

The completed Scorecard presents the five most recent years of available data for each measure. It is designed to track and show an individual distributor's performance improvements over a period of time. The distributor's annual Scorecard will be published by the distributor and the OEB on their respective websites. Therefore, the Scorecard has been designed to be relevant and meaningful to customers and other stakeholders.

Along with the Scorecard, the OEB publishes a report each year on the benchmarking of electricity distributor cost performance. In 2013, the OEB released its *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (the Benchmarking Report) in which it determined the econometric model being used to benchmark distributors' total cost performance. The model controls for the impact of various factors beyond management's control on a distributor's total costs and generates an efficiency ranking based on the percentage deviation between actual and predicted costs. In its Benchmarking Report, the OEB determined that each year distributors will be assigned to one of five groups based on their annually benchmarked cost performance. The OEB has included the cost control measures (Efficiency Assessment, Total Cost per Customer, and Total Cost per km of Line) as a part of the distributor's scorecard.

In its rate application, a distributor should discuss its performance for each of the distributor's scorecard measures over the last five years, and explain the drivers for its performance. As a minimum requirement, the distributor should discuss its plan(s) for continuous improvement, including any short-, medium-, and long-term performance improvement target(s) that are being set by the distributor for itself, that would lead to enhancements to the distributor's scorecard performance over the term of the rate-setting plan. The application should discuss how the distributor's self-assessment has informed its business plan and the application.

2. 1 Exhibit 1: Administrative Documents

The items identified in this section provide the background and summary to the application as filed and are grouped into eight sections:

1) Management Discussion and Analysis (MD&A)
2) Executive Summary
3) Customer Engagement
4) Financial information
5) Materiality thresholds
6) Administration
7) Applicant Overview
8) Corporate Governance
9) Letters of Comment

2.1.1 Management Discussion and Analysis

An applicant's business plan is fundamental to the evaluation of an application. It should describe both the company's goals and its plans to meet them. Each of these is fundamental to evaluating whether the company's objectives are appropriately aligned with the preferences of its customers and whether the company is well positioned to deliver on its goals.

Accordingly, a distributor must provide plain language information about its objectives and business plan, how these relate to what is being sought in the application and how they align with the objectives of the RRFE. The application should also describe whether and how a distributor's objectives have changed, and how the plan to deliver on certain goals reflects customer feedback. This information will allow the OEB to understand the impacts of the business plan on key areas of the application such as customer service, system reliability, costs and bill impacts. Therefore, a distributor should provide the OEB with a broad overview of the utility, past and expected performance and its plans.

2.1.2 Executive Summary

In addition to providing its overall business strategy, including a narrative of how its approach supports the four outcomes established by the OEB in the RRFE report, the applicant has an opportunity in this section to identify key elements of its application. As a minimum, a brief summary of the following items must be provided, if applicable. Applicants must separately identify in the Executive Summary all proposed changes in the application that will have a material impact on customers, including any changes to other rates and charges that may affect discreet customer groups. Applicants must also identify the specific customers or customer groups that will be impacted by each such proposal.

A. Revenue Requirement

- Service Revenue Requirement requested for the test year
- Increase/decrease ($ and %) from the most recent approved service revenue requirement
- Schedule of main drivers of revenue requirement changes from the last OEB-approved year.

B. Budgeting and Accounting Assumptions

- Economic Overview (such as growth and inflation)
- Identification of accounting standard used for test year and brief explanation of impacts resulting from any change in accounting standards.

C. Load Forecast Summary

- Load and customer growth (percentage change kWh and change in customer numbers from last OEB-approved)
- Brief description of forecasting method(s) used for customer/connection and consumption/demand.

D. Rate Base and Capital Plan

- Summary of the major drivers of the Distribution System Plan
- Rate Base requested for the test year
- Change in Rate Base from last OEB-approved ($ and %)
- Capital Expenditures requested for the test year
- Change in Capital Expenditures from last OEB-approved ($ and %)

- Summary of any costs requested for renewable energy connections/expansions, smart grid, and regional planning initiatives
- Total amount ($) the Applicant seeks to recover from all ratepayers for renewable energy connection costs per O.Reg. 330/09.

E. Operations, Maintenance and Administration Expense

- OM&A for the test year, and the change from last OEB-approved ($ and %)
- Summary of overall drivers and cost trends
- Inflation rates used for OM&A forecasts
- Total compensation for the test year and the change from last OEB-approved ($ and %).

F. Cost of Capital

- A statement as to whether or not the Applicant is using the OEB's cost of capital parameters as applicable
- Summary of any deviations from the OEB's cost of capital methodology.

G. Cost Allocation and Rate Design

- Summary of any deviations from the OEB's cost allocation and rate design methodologies
- Summary of any significant changes proposed to revenue-to-cost ratios and fixed/variable splits
- Summary of any proposed mitigation plans to address rate impacts on specific customer classes or overall.

H. Deferral and Variance Accounts

- Total disposition ($) including split between Regulated Price Plan (RPP) and non-RPP customers
- Disposition period
- Any new Deferral and Variance Accounts (DVAs) requested and any requested elimination of existing DVAs.

I. Bill Impacts

- Summary of total Bill Impacts ($ and %) for typical customers in all customer classes.

2.1.3 Customer Engagement

The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customers' needs and expectations. The OEB expects distributors to provide an overview of customer engagement activities that the distributor has undertaken with respect to its plans and how customer needs, preferences and expectations have been reflected in the distributor's application.

Distributors should specifically discuss in the application how they informed their customers of the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e. costs, benefits and the impact on rates). The application should discuss any feedback provided by customers and how this feedback shaped the final application.

Distributors should also reference any other communications sent to customers about the application, such as bill inserts, town hall meetings held, or other forms of outreach undertaken to engage customers and explain to them how the application serves their needs and expectations, and the feedback heard from customers through these engagement activities.

Distributors should complete Appendix 2-AC Customer Engagement Activities Summary. It is the OEB's expectation that distributors identify explicitly the outcomes of customer engagement in terms of the impacts on the distributor's plans, and how that information has shaped the rate application.

The planning elements of customer engagement activities are to be filed as part of the capital plan requirements in Chapter 5.

2.1.4 Financial Information

This section must include the following:

- Non-consolidated audited financial statements of the utility (i.e. excluding operations of affiliated companies that are not rate regulated) for which the application has been made, for the most recent three historical years (i.e. two years' statements must be filed, covering three years of historical actuals). If the most recent final historical audited financial statements are not available at the time the application is filed, draft financial statements must be filed and the final audited financial statements must be provided as soon as they are available.

- A detailed reconciliation of the financial results shown in the audited financial statements with the regulatory financial results filed in the application, including a reconciliation of the fixed assets, for example in order to separate non-utility businesses. This must include the identification of any deviations that are being proposed between the audited financial statements and the regulatory financial results, including the identification of any prior OEB approvals for such deviations.

- Annual Report and Management's Discussion and Analysis for the most recent year of the parent company, if applicable.
- Rating Agency Report(s), if available.
- Prospectuses, information circulars, etc. for recent and planned public debt or equity offerings.
- Change in tax status (e.g. from a corporation to a limited partnership) must be disclosed.
- Existing accounting orders and list of any departures from the Uniform System of Accounts, including references to accounting orders;
- The accounting standard(s) used for general purpose financial statements and when they were adopted.
- If an applicant is conducting non-utility businesses, such as generation, it must confirm that the accounting treatment it has used has segregated all of these activities from its rate-regulated activities. Distributors owning generation facilities should consult the OEB's *Guidelines: Regulation and Accounting Treatments for Distributor-Owned Generation Facilities* G-2009-0300, September 15, 2009, or any successor document.

2.1.5 Materiality Thresholds

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

Unless a different threshold applies to a specific section of these Filing Requirements, the default materiality thresholds are as follows:

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

- $1 million for a distributor with a distribution revenue requirement of more than $200 million.

An applicant may provide additional details below the threshold if it determines that this may be helpful to the OEB. Applicants are reminded that the onus is on the applicant to make its case and ensure that the OEB has the information it needs to properly assess and deliberate on the application.

2.1.6 Administration

This section must include the following:

- Table of Contents

- The contact information for the primary contact for the application. This may be a person within the applicant's organization other than the primary licence contact (the primary contact's name, address, phone number, fax and email address must all be provided). The OEB will communicate with this person during the course of the application. After completion of the application, the OEB will revert communication to the primary licence contact.

- Identification of any legal or other representation for the application.

- Confirmation of the applicant's internet address for purposes of viewing the application and related documents, and any social media accounts used by the applicant to communicate with its customers.

- For each of proposed changes in the application that will have a material impact on customers, including any change to any rate or charge, a clear and specific statement of what individual customers and customer groups would be affected by the proposed change.

- A statement of where the notice of hearing should be published and the rationale for why the stated publication(s) is/are appropriate. The OEB has implemented a new publication process and no longer requires that the applicant publish the notice of hearing. However, the OEB still requires the applicant's recommendation regarding publication.

- Bill impacts (the bill impacts that result only from distribution cost changes as per sub-total A of Appendix 2-W) to be used for the notice of application for a typical residential customer using 800 kWh per month and for a General Service < 50kW customer using 2000 kWh per month, and as appropriate given the consumption patterns of the distributor's customers.

- Statement as to the form of hearing requested (i.e. written or oral) and an explanation of the applicant's preference.

- The requested effective date, list of specific approvals requested and relevant section(s) of legislation. All approvals, including accounting orders (deferral and variance accounts) which the applicant is seeking, must be separately identified in this exhibit and clearly documented in the appropriate sections of the application.

- A statement identifying all deviations from the Filing Requirements, if any, and an explanation for those deviations.

- A statement identifying and describing any changes to methodologies used in previous applications.

- Identification of OEB Directives from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision).

- Reference to the distributor's Conditions of Service. The distributor does not need to file its Conditions of Service, but must provide a reference to where its Conditions of Service are publicly available (e.g., on the distributor's website), and confirm that this is the current version. A description of any changes that have been made since the last cost of service application must be provided. If the Conditions of Service would also change as a result of approval of the application, the distributor must identify all such changes.

2.1.7 Applicant Overview

The following information must be filed:

- Description of applicant's service area:

    - 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 capital expansion or replacement programs.

- A description of whether the distributor is a host distributor (i.e. distributing 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(s)). The distributor must identify any embedded and/or host distributor(s). Partially embedded (i.e., where part of the distributor's network is served by one or more host distributors but where the utility is also connected to the high voltage transmission network) status must also be clearly identified, including the percentage of load that is supplied through the host distributor(s).

- Statement as to whether or not the distributor has had any transmission or high voltage assets (> 50kV) deemed previously by the OEB as distribution assets and whether or not there are any such assets for which the distributor is seeking OEB approval to be deemed as distribution assets in the present application.

2.1.8 Corporate Governance

The performance-based approach to regulation, as outlined in the RRFE Report, is based on the achievement of outcomes. The emphasis on results rather than activities places greater importance on robust and effective corporate governance structures and practices. A distributor's corporate governance practices may impact the distributor's achievement of the OEB's four outcomes. Good corporate governance is therefore an important indicator of the likely success of a distributor's plans.

The OEB has undertaken a policy consultation on corporate governance which is in progress. This policy consultation will provide the OEB with a greater understanding of corporate governance structures and practices that are currently in place for electricity distributors.

The OEB will continue to seek details on a distributor's Board of Directors and how it operates to inform the OEB of current practices. However, the OEB does not expect to make any determinations on the appropriateness of governance until the OEB has completed its policy consultation.

The following information must be filed:

- A description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company board and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure (including any changes in legal organization and control).

- The number of directors on the board of directors, the number of directors that are independent, a statement as to whether or not there is a policy on the number or proportion of independent directors, and a description of what the board of directors does to facilitate its exercise of independent judgment in carrying out its responsibilities.

- The text of the board of directors' written mandate. If the board of directors does not have a written mandate, a description of how the board of directors identifies its role and responsibilities.

- A schedule of the meetings of the board of directors in the current fiscal year (2015 for 2016 cost of service filers).

- A description of what measures, if any, the board of directors takes to provide continuing education for its directors. If the board of directors does not provide continuing education, describe how the board of directors ensures that the directors maintain the skill and knowledge necessary to meet their obligations as directors.

- A statement as to whether or not the board of directors has adopted a written code for the directors, officers and employees. If the board has adopted a written code, provide a copy of the code and describe how the board monitors compliance with its code, or if the board of directors does not monitor compliance, explain whether and how the board of directors satisfies itself regarding compliance with its code.

- A description of the process by which the board of directors identifies and selects new candidates for nomination to the board of directors.

- Identification of any committees of the board of directors, and for each committee identified, provide a description of the functions of the committee and the text of the charter for the committee, if one exists. If there is an audit committee, provide a statement as to whether or not each of the members of the committee is independent and financially literate.

2.1.9 Letters of Comment

This section must include all responses to matters raised in letters of comment filed with the OEB during the course of the proceeding.

2.2 Exhibit 2: Rate Base

This exhibit includes information on:

1) Rate Base
2) Capital Expenditures
3) Service Quality and Reliability Performance.

2.2.1 Rate Base

This exhibit must include the following sections:

1) Overview
2) Gross Assets – Property, Plant and Equipment and Accumulated Depreciation
3) Allowance for Working Capital
4) Treatment of Stranded Assets Related to Smart Meter Deployment.

2.2.1.1 Overview

The applicant must provide a complete appendix 2-BA.

For rate base, the applicant must include the opening and closing balances for each year, and the average of the opening and closing balances for gross fixed assets and accumulated depreciation. If an applicant uses an alternative method, such as calculating the average in-service fixed assets based on the average of monthly values, it must document the methodology used. Rate base shall also include an allowance for working capital (described below).

At a minimum, the information filed in support of the requested rate base must include data for the Historical Actuals, Bridge Year (actuals to date and 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. Written explanations must be provided where there is a year-over-year variance greater than the applicable materiality threshold.

If continuity statements have been restated for the purposes of the application (e.g., due to changes in accounting standards or to reflect corrections in historical audited values), the utility must provide a thorough explanation for the restatement and also provide a reconciliation to the original statements.

The following comparisons must be provided:

- Historical OEB-approved vs. Historical Actual (for the most recent historical OEB-approved year)
- Historical Actual vs. preceding Historical Actual (for the relevant number of years)
- Historical Actual vs. Bridge
- Bridge vs. Test Year.

The opening and closing balances of gross fixed assets and accumulated depreciation that are used to calculate the fixed asset component of rate base must correspond to the respective balances in the fixed asset continuity statements. In the event that the balances do not correspond, the applicant must provide an explanation and reconciliation. This reconciliation must be between the December 31, 2015 and December 31, 2016 net book value balances reported on the Fixed Asset Continuity Schedule (Appendix 2-BA) and the balances included in the rate base calculation. Examples of adjustments that would be made to the fixed asset continuity schedule balances for rate base calculation purposes are the removal of the amounts for Construction Work in Progress and Asset Retirement Obligations.

A distributor may include in-service balances previously recorded in deferral or variance accounts, such as smart meters or renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, but disposition is being requested in this application. This may result in opening balances not reconciling to the closing bridge year property, plant and equipment balances. In this situation, the distributor must clearly show in its evidence (e.g., Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation.

The information outlined in Appendix 2-BA must be provided for each year, in both the application document and in working Microsoft Excel format.

2.2.1.2 Gross Assets – Property Plant and Equipment and Accumulated Depreciation

The applicant must provide the following information:

- Breakdown by function (transmission or high voltage plant, distribution plant, general plant, other plant) for required statements and analyses
- Detailed breakdown by major plant account for each functionalized plant item. For the test year, each plant item must be accompanied by a description
- Summary of any incremental capital module adjustment(s), including what was approved and what was spent, if the distributor received approval for an incremental capital module adjustment as part of a previous IRM application.

Continuity statements must be reconcilable to the calculated depreciation expenses, under Exhibit 4 – Operating Costs, and presented by asset account. Further guidance is included in the spreadsheet appendices and under section 2.1.4 below.

2.2.1.3 Allowance for Working Capital

In a letter dated June 3, 2015 the OEB provided an update to the OEB's policy for the calculation of the allowance for working capital. The applicant may continue to take one of two approaches for the calculation of its allowance for working capital: (1) use a default allowance approach or (2) the filing of a lead/lag study.

The only exception for cost of service applicants is if the applicant has been previously directed by the OEB to undertake a lead/lag study on which its current working capital allowance is based. Under such circumstances, the applicant must either continue to use the results of that study or, (1) in the event the study resulted in a working capital allowance above the current default allowance, or (2) it wishes to propose a revision to its allowance, the applicant must file an updated study in support of its proposal. In the absence of such circumstances the two approaches are:

- 7.5% Allowance Approach

  The 7.5% Allowance Approach is calculated to be 7.5% of the sum of Cost of Power and Operations, Maintenance and Administration (OM&A).

  The commodity price estimate used to calculate the Cost of Power must be determined by the split between RPP and non-RPP customers based on actual data and using the most current RPP (TOU) price. The calculation must reflect the most recent Uniform Transmission Rates approved by the OEB (EB- 2014-0357), issued on January 8, 2015 for 2015 rates and effective January 1, 2015. The calculation must include the impacts arising from the Smart Metering Entity charge approved by the OEB on March 28, 2013 in its EB-2012-0100/EB-2012-0211 Decision and Order, which is to last until October 31, 2018, subject to review and adjustment by the OEB.

- Lead/Lag Study

  A lead/lag study analysis for two time periods; namely:

  - The time between the date customers receive service and the date that the customers' payments are available to the distributor (the lag).
  - The time between the date when the distributor receives goods and services from its suppliers and vendors and the date that it pays for them (the lead).

Leads and lags are measured in days and are dollar-weighted. The dollar-weighted net lag (i.e. lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. This amount is included in the applicant's rate base determination. The lead-lag study should reflect the distributor's actual billing and settlement processing timelines as well as consider relevant changes to the operating environment, such as the OEB's requirement that distributors implement monthly billing by the end of 2016, the elimination of the Ontario Clean Energy Benefit, cessation of the debt retirement charge for residential customers and the introduction of the Ontario Electricity Support Program effective in 2016.

2.2.1.4 Treatment of Stranded Assets Related to Smart Meter Deployment

The OEB's *Guideline G-2008-0002: Smart Meter Funding and Cost Recovery* provided two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters: (1) leave them in rate base (i.e. Account 1860); or (2) record them in "Sub-account Stranded Meter Costs" of Account 1555.

Since the issuance of this guideline, distributors should have completed their smart meter deployments. Distributors are entitled to receive a rate of return for prudent investments in smart meters while recorded in Account 1555, from the time of their smart meter in-service deployment to the time of the disposition of the smart meters in rates. The earned return on the smart meter investments serves to recognize that the meters are used or useful while they are recorded in Account 1555, although they are not yet included in rate base.

Accounting guidance in the December 2010 Accounting Procedures Handbook FAQs (Q and A #15) provides information as to how the cost of service rate-setting process may be used to address the recovery by distributors of costs associated with stranded meters.

On December 15, 2011, the OEB issued *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition*. Section 3.7 and Appendix A-1 of that guideline provide the most current guidance on the treatment for recovery of costs for stranded meters replaced by smart meters, and the approach has been approved in subsequent rate applications seeking disposition and recovery of net stranded meter costs.

If the recovery of stranded conventional meters replaced by smart meters has not been reviewed and approved for recovery in a previous application, the distributor must make a proposal for a Stranded Meter Rate Rider if it intends to recover residual amounts. A completed Appendix 2-S must be provided as well as the following:

- The total estimated NBV of the stranded meters as of December 31, 2015, or a revised amount calculated in accordance with the above-noted accounting guidance, must be removed from rate base (see Appendix 2-S). The 2016 revenue requirement must not include either a return on capital (i.e. debt cost and return on equity) or depreciation expense associated with the total estimated stranded meter costs removed from rate base.
- The total estimated NBV of the stranded meters must be recovered through separate rate riders for the applicable customer classes. A distributor must outline the manner in which it intends to allocate recovery of the NBV of the stranded meters to the applicable customer rate classes and the rationale for the selected approach.
- The total estimated stranded meter costs must be tracked in "Sub-account Stranded Meter Costs" of Account 1555.

- The associated recoveries from the separate rate riders must also be recorded in this sub-account to reduce the balance in the sub-account through the recovery period.

Recovery of stranded costs will be through separate rate riders (Stranded Meter Rate Riders) for the applicable customer classes. Distributors wishing to propose a different approach to that outlined above must provide a full explanation and justification of the proposed approach, and explain why the accepted practice described above would not be suitable for their circumstances.

This policy addresses the recovery of stranded conventional meters as a result of the smart meter implementation program. For any other circumstances of stranded assets, distributors must provide a detailed business case.

2.2.2 Capital Expenditures

Included within this exhibit are the following sections, which will include the Distribution System Plan as outlined in Chapter 5.

1) Planning
2) Required Information
3) Capitalization Policy
4) Capitalization of Overhead
5) Costs of Eligible Investments for Distributors
6) New Policy Options for the Funding of Capital
7) Addition of ACM/ICM Assets to Rate Base
8) Service Quality and Reliability Performance

2.2.2.1 Planning

A distributor filing a cost of service rate application for 2014 or subsequent rate years must include in its application a consolidated DSP as outlined in Chapter 5.

To facilitate better planning, prioritization and pacing of capital expenditures, the RRFE Report concluded that an integrated approach to planning is preferred. This means that all categories of system investments must be consolidated in a distributor's capital expenditure plan, including investments to renew and expand the distribution system, investments identified in a regional planning process, and investments to accommodate the connection of renewable generation or to implement a smart grid. To implement this integrated approach, the OEB issued filing requirements and guidance specifically in relation to the DSP, which are documented in Chapter 5 of the Filing Requirements.

Regional Planning

Infrastructure planning on a regional basis is required to ensure that regional issues and requirements are effectively integrated into utility planning processes, which will, in turn, help promote the cost-effective development of electricity infrastructure in the Province. The effective use of regional infrastructure planning and the inclusion of regional considerations in distributors' plans will also be key to ensuring that, through coordinated development and implementation, smart grid investments are made in distribution and transmission systems that will best serve the interests of the region.

Distributors will therefore be expected to file evidence that demonstrates that regional issues have been appropriately considered and, where applicable, addressed in developing the utility's proposed capital expenditure plan. As part of its planning, a distributor should consider municipal planning, including any plans for expansion of municipal boundaries from a regional perspective to demonstrate the most cost-effective solutions are being considered.

The OEB recognizes that formal regional infrastructure plans will not be available in all of the identified regions for a number of years. However, distributors proposing major new infrastructure, such as a new transformer station, should be able to demonstrate that they have considered all options, including those involving neighbouring distributors or the supplying transmitter. Furthermore, distributors will be expected to have considered conservation as one of the options to defer the need for infrastructure investments. While the OEB will consider regional infrastructure plans in its regulatory processes, the OEB will not formally approve these plans.

Planning Horizon

The RRFE Report concluded that a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles. This time horizon, along with the integrated approach to planning, will allow distributors to pace and prioritize expenditures with a view to the impact on the total bill for customers. This planning horizon should also help to provide cost predictability for both the distributor and its customers.

Chapter 5 is to be used by distributors in combination with this Chapter 2. Chapter 5 supersedes the OEB's *Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence* (EB-2009-0397). However, information on the costs of any eligible investments identified pursuant to Chapter 5 for which a distributor is seeking prudence review and approval is to be provided, as set out in section 2.2.2.5 below.

2.2.2.2 Required Information

As part of this exhibit, distributors must file a consolidated DSP in accordance with Chapter 5 for matters pertaining to asset management, renewable energy generation, smart grid and regional planning. All elements of the DSP must be contained in one integrated and cohesive document that contains each of its prescribed components. The DSP must be filed as a stand-alone and self-sufficient item, as a discrete element within Exhibit 2. Most distributors in recent years have found it convenient to file the DSP as an appendix to Exhibit 2, and this has proven to be workable for review of the DSP as part of the rate application.

A complete Appendix 2-AB must be filed, providing an overall summary of capital expenditures, in the categories identified by Chapter 5, for the previous four historical years plus the bridge year and the test year. Applicants should make best efforts to categorize historical projects into the DSP categories. At a minimum, for historical years, applicants must provide the actual totals. Forecasts for the bridge and test years must be provided per the Chapter 5 categories. If no previous plan has been filed, applicants are only required to enter the OEB approved amounts in the "plan" column for the last rebasing year.

Applicants must also provide a complete Appendix 2-AA along with the following information about capital expenditures on a project-specific basis. This information is incremental to the requirements in Chapter 5:

- Written explanation of variances, including that of actuals versus the OEB-approved amounts for the applicant's last OEB-approved cost of service application
- For capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress (CWIP).

Applicants should also provide the components of other capital expenditures such as for non-distribution activities, including a reconciliation of all capital components to the Total Capital Budget.

2.2.2.3 Capitalization Policy

The applicant must provide its capitalization policy, including changes to that policy since its last rebasing application filed with the OEB.

Per the OEB's letter of July 17, 2012, electricity distributors that elected to remain on CGAAP in 2012 must have implemented regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes were mandatory in 2013 for all distributors that had not made these changes, and therefore, all cost of service applications for 2016 rates should reflect that these changes were made in 2012 or 2013.

These accounting changes under CGAAP must be implemented consistent with the OEB's regulatory accounting policies as set out for MIFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, the Kinectrics Report, and the APH, effective January 1, 2012.

If the applicant has changed its capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons subsequent to the changes as per the OEB's letter, the applicant must identify the changes and the causes of the changes.

2.2.2.4 Capitalization of Overhead

The applicant must complete Appendix 2-D regarding overhead costs on self-constructed assets.

Burden Rates

The applicant must identify the burden rates related to the capitalization of costs of self-constructed assets. Furthermore, if the burden rates were changed since the last rebasing application, the applicant must identify the burden rates prior to and after the change.

2.2.2.5 Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

For any costs incurred to make eligible investments as described in section 79.1 of the OEB Act and O.Reg. 330/09 under the Act and documented in accordance with Chapter 5, including any facilities forecast to enter service beyond the test year, the distributor must provide a proposal, where applicable, to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09, taking into account the OEB's Report on the *Framework for Determining Direct Benefits* (EB-2009-0349) (the Direct Benefits Report). Where applicable, applicants must file a draft accounting order to establish a variance account tracking the IESO payment revenues against the actual spending.

The component of such investments not eligible for rate protection will be treated similarly to any other new investment undertaken by a distributor and will not be separately tracked. For renewable generation connection investments, distributors can assume the direct benefit percentage to be 17%; for renewable enabling improvement investments, the assumed direct benefit percentage is 6%. Distributors will continue to have the option to undertake a more rigorous "detailed" direct benefit assessment based on the criteria set out in the Direct Benefits Report, where the distributor believes the standard percentages will not be reflective of the direct benefits.

Appendices 2-FA through 2-FC must be filed, identifying all eligible investments (to a maximum of five years) for which cost recovery is required. These appendices provide information on all costs (capital and OM&A), and the shares of total costs to be recovered from all Ontario ratepayers (net of direct benefits) and the distributor's ratepayers. The appendices also provide a revenue requirement calculation for the asset costs to be recovered annually in accordance with O.Reg. 330/09 – Provincial Rate Protection.

2.2.2.6 New Policy Options for the Funding of Capital

On September 18, 2014, the OEB issued the *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219)*. The Advanced Capital Module (ACM) reflects an evolution of the Incremental Capital Module (ICM) adopted by the OEB in 2008.

The ACM expands the ICM concept to incorporate the concept of recovery for qualifying incremental capital investments during the Price Cap IR period with an opportunity to identify and pre-test such discrete capital projects documented in the DSP as part of the cost of service application.

As part of a cost of service application, a distributor may propose qualifying ACM capital projects that are expected to be made and come into service during the subsequent Price Cap IR term. These will be discrete projects as documented in the DSP. The distributor must also identify that it is proposing ACM treatment for these future projects, and provide the cost information and materiality threshold calculations to show that these would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application. The ACM Report provides further details on the information required. A distributor applying for an ACM must file a completed spreadsheet Capital Module Applicable to ACM and ICM.

Cost recovery (i.e. rate riders) for qualifying ACM projects in the subsequent Price Cap IR period will not be determined in the cost of service application. This determination will be made in the Price Cap IR application for the year in which the capital investment will be made and comes into service. At that time, the distributor must file updated information on the forecasted costs and demonstrate that the capital project still qualifies for incremental capital funding and recovery. However, the nature and need for the project will be determined as part of the DSP during the cost of service application.

Capital projects not anticipated at the time of the DSP or for which cost forecasts are not sufficiently robust may still qualify for ICM treatment. Such projects may be proposed in a subsequent Price Cap IR application and will be thoroughly tested at that time.

2.2.2.7 *Addition of Previously Approved ACM and ICM Project Assets to Rate Base*

Any distributor that has an approved ACM[2] or ICM from a previous Price Cap IR application must file a schedule of the ACM/ICM capital asset amounts (i.e., property, plant and equipment and associated depreciation) it proposes be incorporated into rate base. The distributor must compare actual capital spending with the OEB-approved amount and provide an explanation for variances. The OEB will make a determination on any true-up treatment of any variance between forecast and actual capital spending during the IRM plan term.

Distributors shall record actual amounts in the following sub-accounts of Account 1508 – Other Regulatory Assets:

- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures
- Account 1508 – Other Regulatory Assets, Sub-account Depreciation Expense
- Account 1508 – Other Regulatory Assets, Sub-account Accumulated Depreciation
- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues.

The distributor shall also record monthly carrying charges in the following sub-accounts. Carrying charge amounts are calculated using simple interest applied to the monthly opening balances:

- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures, Carrying charges.
- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues, Carrying Charges.

The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period as published on the Board's web site.[3]

If the OEB approves the true-up of any variances, the recalculated revenue requirement relating to the OEB-approved ACM/ICM capital expenditures should be compared to the

[2] For 2016 cost of service applications, no previously approved ACM exists as the OEB's ACM policy report is effective with the 2016 rate applications.
[3] See Section 7.5 of the *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued September 18, 2014 for more details.

rate rider revenues collected in the same period and these variances will be refunded to, or collected from, customers through a rate rider.

2.2.2.8 Service Quality and Reliability Performance

The following information must be provided:

- Reported Electricity Service Quality Requirements ("ESQRs"), as set out in Chapter 7 of the *Distribution System Code*, for the last five 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 (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index), for the last five historical years. Reliability performance for SAIDI and SAIFI must be reported for two indicators: (1) All interruptions, and (2) All interruptions excluding Loss of Supply (Cause Code 2).
- As established in the *Report of the OEB: Electricity Distribution System Reliability Measures and Expectations*, distributors' SAIDI and SAIFI performance is expected to meet the average performance over the previous 5 years. In the event performance is worse than the expected benchmark, the applicant must provide an explanation for the under-performance, actions taken to address the issue, and any outcomes, if available.
- Distributors who wish to commit to SAIDI and SAIFI performance benchmarks that are different than the historical average must provide evidence to support the reasonableness of such benchmarks as part of their Chapter 5, Consolidated Distribution System Plan filing.

A completed Appendix 2-G, covering both the Service Quality and Service Reliability indicators, must be filed.

2.3 Exhibit 3: Operating Revenue

This exhibit includes evidence on the applicant's forecast of customers, energy and load, service revenue and other revenue, and variance analyses related to these items.

The applicant must provide its customer, volume and revenue forecast methodologies and weather normalization methodology in this exhibit. The applicant must also document its other sources of revenue. The applicant must include a detailed description of assumptions used. Revenue estimates must be presented excluding commodity (i.e. cost of power) revenues.

The information presented must include:

1) Load and Revenue Forecasts
2) Accuracy of Load Forecast and Variance Analyses
3) Other Revenue.

2.3.1 Load and Revenue Forecasts

The applicant must provide an explanation of the causes, assumptions and adjustments for the volume forecast. All economic assumptions and data sources used in the preparation of the load and customer count forecast must 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 used. The OEB recognizes that an important aspect of any case is the uniqueness of the 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 service territory.

The applicant must include in the test year forecast any impacts arising from the persistence of historical conservation and demand management (CDM) programs, as well as the forecasted impacts arising from new programs in the bridge and test years through the current 6-year (2015-2020) CDM framework. This CDM component of the forecast must be specifically identified by customer class, as the amount approved by the OEB will be the basis for amounts tracked in the lost revenue adjustment mechanism variance account (LRAMVA).

Two types of load forecasting models have generally been filed with the OEB 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 using these approaches, the following information is required for these two modelling methodologies, when used.

Distributors must complete Appendix 2-IA: Summary and Variances of Actual and Forecast Data.

2.3.1.1 Multivariate Regression Model

The following must be provided:

- 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, 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.). A discussion of modelling approaches considered and alternative models tested must be provided;

- Explanation of the weather normalization methodology proposed including:
    - If monthly Heating Degree Days (“HDD”) and/or Cooling Degree Days (“CDD”) are used to determine normal weather, the monthly HDD and CDD based on a) 10-year average and b) a trend based on 20-years;
    - Definition of HDD and CDD:
        - Climatological measurement point(s) (i.e. identification of Environment Canada weather station(s)) and why these are appropriate for the distributor’s service territory; and
        - Identification of base numbers from which HDDs and CDDs are measured (e.g., 18° C or other).
    - In addition to the proposed test year load forecast, the load forecasts based on: a) 10-year average; and b) 20-year trends in HDD and CDD.
    - Rationale as to why the proposed normal weather methodology was chosen.
- Sources of data used for both the endogenous and exogenous variables. Where a variable has been constructed, a complete explanation of the variable, data used and source of the data must be provided. Where a utility has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. billing data not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation as to why the constructed demand series is suitable for modelling;
- Explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.).

Data and regression model and statistics used in the customer and load forecast must be provided in working Microsoft Excel format. This would include showing the derivation of any constructed variables where practical.

2.3.1.2 Normalized Average Use per Customer (“NAC”) Model

The following must be provided:

- 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

- Description of how CDM impacts have been accounted for in the historical period, and how CDM impacts, including the CDM targets in the bridge and test years, are factored into the test year load forecast
- Discussion of weather normalization considerations taken into account in developing the NAC forecast.

2.3.1.3 CDM Adjustment for the Load Forecast for Distributors

Consistent with the OEB's *Guideline EB-2012-0003 - Guidelines for Electricity Distributor Conservation and Demand Management*, it is expected that the distributor will integrate an adjustment into the 2016 load forecast that takes into account CDM impacts. The distributor should ensure that it has fully considered measured impacts persisting from prior years, and the expected impacts from new programs on the 2016 load forecast.

The CDM targets and the LRAMVA balances are based on the reported IESO[4] results, which are annualized. It is recognized that new CDM programs in a year are not in effect for the full year, although persistence of prior years' programs will be. Therefore, the actual impact on the load forecast for the first year of a program should not be the full annualized amount. For this reason, the amount that will be used for the LRAMVA will be related to, but not necessarily equal to, the CDM adjustment for the load forecast.

Further, the actual results for 2011-2014 historical years, which are used to develop the base forecast, include the impacts of 2011 to 2014 CDM programs. The CDM adjustment to the load forecast should also take into account the historical CDM results factored into the base load forecast before the CDM adjustment, in order to avoid double counting the impacts.

The distributor should document the CDM savings to be used as the basis for the 2016 LRAMVA balance and the corresponding adjustment to the 2016 load forecast. In addition, the allocation of the CDM savings for the LRAMVA and the load forecast adjustment should be provided by customer class and for both kWh and, as applicable, kW. The distributor should document its proposal adequately. Appendix 2-I is provided as one approach for calculating the aggregate amounts for the LRAMVA and the corresponding CDM adjustment to the load forecast.

Appendix 2-I has been updated for 2016 cost of service applications to take into account the 2011-2014 CDM impacts as reported by the IESO, and the forecasted 2015 CDM program impacts assuming that the distributor achieves 100% of its 2011-2014 CDM licence condition target. If a distributor has better information on CDM results, it should use that information.

[4] Formerly the Ontario Power Authority

On March 31, 2014, the Minister of Energy issued a directive to the OEB and a letter of direction to the IESO regarding the CDM framework for the period January 1, 2015 to December 31, 2020. The CDM framework is expected to achieve 7 TWh of energy reductions province-wide over this six-year period, consistent with the 2013 Long-term Energy Plan. The distributor should include a proposal, with the appropriate rationale, for the level of CDM reductions reflected in the 2016 load forecast.

Appendix 2-I has been modified to take into account projected savings in 2016 for 2016 CDM programs that the distributor will undertake as part of the new 2015-2020 CDM plan. The distributor can alter the default methodology for the 2016 CDM kWh savings to align with its 2015-2020 CDM plan.

2.3.2 Accuracy of Load Forecast and Variance Analyses

The applicant must demonstrate the historical accuracy of the load forecast approach for at least the past 5 years by providing the following, as applicable:

- Schedule of volumes (in kWh and in kW for those rate classes that use this charge determinant), revenues, customer/connections count by rate class and total system load in kWh) for:
  - Historical Actual for the past 5 years
  - Historical OEB-approved
  - Historical Actual for the past 5 years – weather normalized, if available
  - Bridge Year
  - Bridge Year – weather normalized
  - Test Year

A minimum of 5 historical years of customer and connection numbers must be provided. For each rate class, the applicant must also provide the following:

- 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.
- Explanations for changes in the definition of, or major changes in the composition of, each class. Major changes would include material loss, gain or re-classification of customers in one or more customer classes.
- Weather-normalized (if applicable) average historical actual consumption per customer for historical 5 years and forecasted weather-normalized average consumption for the Bridge Year and Test Year.

- For each rate class, an explanation of the net change in average consumption from last OEB-approved and actuals for Historical, Bridge and Test Years.
- Details for the development of the billing kW value (e.g.., approach for converting from kWh to kW) for applicable classes.
- Revenues, provided on the basis of both existing and proposed rates.

The applicant must provide the following variance analyses and relevant discussion for volumes, revenues, customer/connections count and total system load:

- Historical OEB-approved vs. Historical Actual
- Historical OEB-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
- Bridge Year – weather-normalized vs. Test Year – weather-normalized.

All data used to determine the customer, demand and load forecasts must be presented and filed in live Microsoft Excel spreadsheet format, as also discussed under section 2.3.1.1 above.

2.3.3 Other Revenue

The following information on each of the Other Distribution revenue accounts (see Appendix 2-H for the required format) must be provided:

- Comparison of actual revenues for historical years to forecast revenue for Bridge and Test Years, including explanations for significant variances in year-over-year comparisons.
- Any new proposed specific service charges, changes to rates or new rules for applying existing specific service charges.
- Any revenue from affiliate transactions, shared services or corporate cost allocations as described in section 2.4.3.2. For each affiliate transaction, identification of the service, the nature of the service provided to affiliated entities, accounts used to record the revenue and the associated costs to provide the service.

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

Distributors must identify any discrete customer groups that may be materially impacted by changes to other rates and charges.

2.4 Exhibit 4: Operating Expenses

Exhibit 4 includes information that summarizes the Operating, Maintenance and Administrative (OM&A) Expenses, Depreciation Expense and Taxes, collectively referred to as Operating Expenses.

With the release of the RRFE report, the OEB is adopting an outcomes-based approach to regulation. On this basis, the review of OM&A expenses transitioned, beginning with the 2014 cost-of-service applications towards an output- and program-focused review in place of the previous approach, which focused significant attention on discrete elements of the inputs to OM&A expenses. The OEB recognized that a transition period to achieve the full adoption of such an approach is necessary. As such, to the extent possible, applicants were required to do their year-over-year variance analyses based on their OM&A programs. For example, an OM&A program could be vegetation management, insulator washing, pole testing, cable locates, etc.

In this context, the OEB eliminated two appendices from the 2012 version of the Filing Requirements (2-G and 2-H) that required OM&A details on an account by account basis. For 2014 applications, the OEB inserted a new appendix, 2-JC: OM&A Programs Table and Variance Analysis, which provides OM&A details and variance analysis on a program basis. This table must reflect the entire OM&A envelope requested for recovery as part of the 2015 and later rate applications. All applicants must provide information for the bridge and test years. The Recoverable OM&A Cost Driver Table (Appendix 2-JB) should be used to provide high-level information on the cost drivers of OM&A expenses. All applicants must file all remaining OM&A appendices, including appendix 2-JA that breaks down the OM&A envelope into major categories (Operations, Maintenance, etc.).

This exhibit must include the following sections:

- Overview
- Summary and Cost Driver Tables
- Program Delivery Costs with Variance Analyses
- Depreciation/Amortization/Depletion
- Taxes and Payments in Lieu of Taxes (PILs)
- CDM

2.4.1 Overview

The overview 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 relative to historical and bridge years.
- Overall trends in costs.
- Inflation Rate assumed. The OEB determines and publishes an appropriate inflation rate (the Input Price Index or IPI) for use by utilities with respect to IRM rate applications; distributors should be mindful of this rate, and, if adopting a different inflation rate, should provide a full explanation and support for their proposal.
- Business environment changes.

2.4.2 Summary and Cost Driver Tables

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

- Summary of Recoverable OM&A Expenses (Appendix 2-JA)
- Recoverable OM&A Cost Driver Table (Appendix 2-JB)
- OM&A Programs Table (Appendix 2-JC)
- Recoverable OM&A Cost per Customer and per FTE (Appendix 2-L).

The applicant must identify the overall level of increase (decrease) in OM&A expense in the test year in relation to a decrease (increase) in capitalized overhead. However, applicants are reminded that the OEB required changes to capitalization to be implemented by January 1, 2013. The applicant must provide a variance analysis for the change in OM&A expense for the test year in respect to each of the bridge year and historical years. The applicant must complete Appendix 2-D.

2.4.3 Program Delivery Costs with Variance Analysis

As identified previously, applicants must complete the revised Appendix 2-JC: OM&A Programs Table, making best efforts to identify OM&A costs by program, and, if not, by major functions. This will include a variance analysis between the Test Year costs and the last OEB-approved costs and the most recent actuals. The variance analysis should be limited to variances that are outliers based on the historical trend, and should include an explanation of whether the change was within or outside the applicant's control.

In addition, for each significant change within the applicant's control, the applicant should describe the business decision that was made to manage the cost increase/decrease and the alternatives, including associated costs, assessed by the applicant and rejected in favour of the course of action taken or proposed to be taken.

Further details are required to be filed for the following categories of costs, as discussed further in the sections that follow:

- Employee Compensation
- Shared Services and Corporate Cost Allocation
- Purchases of Non-Affiliate Services
- One-time Costs
- Regulatory Costs
- Low Income Energy Assistance Programs
- Charitable and Political Donations

2.4.3.1 Employee Compensation Breakdown

The applicant must complete Appendix 2-K: Employee Costs in relation to employee complement, compensation, and benefits. Information on labour and compensation must include the total amount, whether expensed or capitalized.

The OEB's RRFE Report established the process of implementing an outcomes-based regulatory model which has, as one of its objectives, the achievement of increased regulatory efficiency by focussing on results instead of activities. The OEB is of the view that, as employee compensation costs are already reflected in the applied-for capital and expense programs, a detailed segregation of compensation is not necessary in the OEB's consideration of the proposed program costs to achieve the expected outcomes.

Accordingly, the OEB has maintained the streamlined approach to the information required in Appendix 2-K which it began with 2014 rates. The OEB will expect subsequent stages of the discovery process to conform to these reduced requirements unless compelling reasons can be provided as to why additional information is necessary.

In place of the details removed from Appendix 2-K, it is the OEB's expectation that distributors will provide a description of their compensation strategy, and clearly explain the reasons for all material changes to head count and compensation, and the outcomes expected from these changes. A complete explanation includes:

- Year-over-year variances, inflation rates used for forecasts, plans for any new employee additions and relevant details on collective agreements (e.g., the date the agreement was signed, the effective date, length of term and any information

available to the applicant on other collective agreements entered into in the same time period).
- Basis for performance pay, eligible employee groups, goals, measures, and review processes for any pay-for-performance plans.
- Any relevant studies conducted by or for the applicant (e.g., compensation benchmarking).

Applicants which are virtual utilities (i.e. utilities which have outsourced the majority of functions, including employees, to affiliates) must also complete this appendix in relation to the employees who are doing the work of the regulated utility. In addition to the information required per Appendix 2-K, the status of pension funding and all assumptions used in the analysis must be provided.

Where there are three or fewer employees in any category, the applicant must aggregate this category with the category to which it is most closely related. This higher level of aggregation must 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 OEB-approved rebasing application, and Historical, Bridge and Test Years. The most recent actuarial report(s) must be included in the pre-filed evidence. What is documented in the tax section of the pre-filed evidence must agree with this analysis.

2.4.3.2 Shared Services and Corporate Cost Allocation

Shared Services are defined as the concentration of a company's resources performing 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.

The applicant must identify all shared services among the affiliated entities, including the extent to which the applicant is a "virtual" utility.

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 third party review of the corporate cost allocation methodology used.

Applicants should ensure and be able to demonstrate, at a minimum, that their approach to corporate cost allocation and shared services results in no more costs being allocated to the distributor than if it was operating as a stand-alone entity.

The applicant must complete Appendix 2-N in relation to each service provided or received for Historical (actuals), Bridge and Test years. The table found in Appendix 2-N must be completed for each year. Additional rows may be added if required. Applicants must provide a reconciliation of the revenue arising from Appendix 2-N with the amounts included in Other Revenue in section 2.3.3.

Variance analyses, with explanations, are required for the following:

- Test Year vs. Last OEB-approved
- Test Year vs. Most Recent Actuals.

The applicant must identify any Board of Director-related costs for affiliates that are included in the utility's own costs.

2.4.3.3 Purchases of Non-Affiliate Services

Utility expenses incurred through the purchase of services from non-affiliated firms must be documented and justified. An applicant must provide a copy of its procurement policy, including information on such areas as the level of signing authority, a description of its competitive tendering process and confirmation that its non-affiliate services purchases are in compliance with it.

For any such transactions above the materiality threshold that were procured without a competitive tender, or are not in compliance with the applicant's procurement policy, the applicant must provide an explanation as to why this was the case, as well as the following information for actuals:

- Summary of the nature of the product or service that is the subject of the transaction.
- A description of the specific methodology used for selecting the vendor, including a summary of the tendering process/cost approach, etc.

2.4.3.4 One-time Costs

The OEB notes that cost of service applications contain costs that, once approved, are recovered annually over the five-year period for which the base rates, as adjusted during the IR term, remain in effect. Accordingly, the applicant must identify one-time costs in the historical, bridge and test years and provide an explanation as to how the costs included in the test year are to be recovered. If a distributor is not proposing that one-time costs be recovered over the test year and the subsequent IRM term (i.e., amortization of cost recovery over the normal five-year period), an explanation must be provided.

2.4.3.5 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. Appendix 2-M must be completed. The applicant must provide information supporting the level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify how such costs are to be recovered (i.e., over what period the costs are proposed to be recovered). For distributors, the recovery period would normally be the duration of the expected cost of service plus IRM term under the Price Cap IR option (i.e., five years). If the applicant is proposing a different recovery period, it must explain why it believes this is appropriate.

2.4.3.6 Low-income Energy Assistance Programs (LEAP)

The OEB recognizes the challenges that energy costs can pose for low income consumers, and believes that there needs to be a comprehensive and province-wide approach for providing assistance to respond to affordability issues.

In March 2009, the OEB issued its *Report of the Board: Low Income Energy Assistance Program* (the LEAP Report) which describes policies and measures for electricity and natural gas distributors to assist low-income energy consumers, including emergency financial assistance.

As set out in the LEAP Report, the OEB has determined that the greater of 0.12% of a distributor's OEB-approved distribution revenue requirement, or $2,000, is a reasonable commitment by all distributors to emergency financial assistance. The $2,000 minimum is intended to ensure that, for smaller distributors, more funding is available than otherwise would be if based solely on a percentage of distribution revenues The LEAP amount must be calculated based on total distribution revenues, and is to be recovered from all rate classes based on the respective distribution revenue of each of those rate classes.

A distributor must include the relevant LEAP amount as part of its OM&A expenses. For greater clarity, OEB-approved total distribution revenue means a distributor's forecasted service revenue requirement as approved by the OEB.

A distributor must also state whether or not any amounts have been included in its test year revenue requirement for legacy programs, such as Winter Warmth. If this is the case, the programs and amounts must be identified and a brief description of each of the programs must be provided.

The LEAP program and funding for LEAP will continue in tandem with the Ontario Energy Support Program that will be in place effective January 1, 2016.

2.4.3.7 Charitable and Political Donations

The OEB understands that charitable donations may well benefit the communities served by the distributor. However, these expenses are not related to the provision of electricity distribution services and therefore do not appropriately form part of the revenue requirement to be recovered from ratepayers.

The applicant must file the amounts paid annually to charitable donations from the last OEB-approved rebasing application up to 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 (e.g. applicable programs under 2.4.3.6 above). If the applicant wishes to recover such contributions, it must provide detailed information for such claims.

The applicant must review the amounts filed to ensure that all other non-recoverable contributions are identified, disclosed and removed from the revenue requirement calculation. The applicant must also confirm that no political contributions have been included for recovery.

2.4.4 Depreciation, Amortization and Depletion

Applicants must demonstrate that the proposed levels of depreciation/amortization expense appropriately reflect the useful lives of the utility's assets and the OEB`s accounting policies.

The Kinectrics Report[5] provides information that the OEB expects distributors will consider as they develop asset service lives to be included in their cost of service applications. However, while the Kinectrics Report contains a range of useful lives for assets, distributors must ensure that these ranges (and the specific useful lives selected within the ranges) are appropriate to their circumstances when preparing an application, and must provide explanations for any proposed useful lives that are not within the ranges contained in the Kinectrics Report.

The information outlined below is required for Depreciation, Amortization and Depletion:

- Details for Depreciation, Amortization and Depletion by asset group for the Historical, Bridge and Test Years, including asset amounts and rates of depreciation or amortization. This must tie back to the accumulated depreciation balances in the fixed asset continuity schedule (Appendix 2-BA) under Rate Base.

[5] *Asset Depreciation Study for Use by Electricity Distributors* (EB-2010-0178), (the "Kinectrics Report"), July 8, 2010;

- The applicant must identify any Asset Retirement Obligations (AROs) and any associated depreciation or accretion expenses related to the AROs, including the basis for and calculation of these amounts.
- The OEB's general policy for electricity distribution rate setting has been that capital additions would normally attract six months of depreciation expense when they enter service in the test year. This is commonly referred to as the "half-year" rule. On June 20, 2014, the OEB initiated a consultation *New Policy Options for the Funding of Capital Investments* (EB-2014-0219). The OEB's consideration of the half-year rule and alternative approaches is still under way. While the policy consultation is still ongoing, distributors can propose an approach in their applications for the OEB's consideration, but must identify their historical practices and must support any variance from the half-year rule whether that variance applies to just the test year, subsequent years, or both.
- The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant must provide a written description of the depreciation practices followed and used in preparing the application. The applicant must provide a summary of changes to its depreciation/amortization policy made since the applicant's last cost of service filing.
- The applicant must ensure that the significant parts or components of each item of PP&E are being depreciated separately, in accordance with its adopted accounting standard. Any deviations from this practice must be explained.

All distributors that deferred the adoption of IFRS and remained under CGAAP in 2012 were expected to have made regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. In support of the depreciation expense policy changes:

- The applicant must use the OEB-sponsored Kinectrics study or provide its own study to justify changes in useful lives.
- The applicant must provide a list detailing all asset service lives and tie this list to the Uniform System of Accounts as appropriate. The applicant must detail differences of its asset service lives from the Typical Useful Lives (TULs) from the Kinectrics Report and provide a detailed explanation for using a service life that is outside the minimum and maximum TULs in the Kinectrics Report. A completed Appendix 2-BB must be filed.
- Applicants must perform a recalculation to determine the average remaining life of the opening balance of assets on the date of making depreciation changes.
- If further depreciation expense policy changes or changes in asset service lives are made subsequent to those made by January 1, 2013, the applicant must identify the changes and provide a detailed explanation for the causes of the changes.

- The applicant must file the applicable depreciation appendices as provided in the Chapter 2 MIFRS Appendices (2-CA to 2-CK).

2.4.5 Taxes or Payments In Lieu of Taxes (PILs) and Property Taxes

Applicants should make use of the stand-alone principle when determining these amounts.[6] Applicants are expected to exercise sound tax planning and are expected, for rate-setting purposes, to maximize tax credits and take the maximum deductions allowed

The applicant must provide the following information:

- Detailed calculations of Income Tax or PILs, as applicable (including a completed pdf and live Microsoft Excel version of the Income Tax /PILs model available on the OEB's web site), including derivation of adjustments (e.g., Tax credits, CCA adjustments) for the Historical, Bridge and Test Years. Regulatory assets and liabilities must generally be excluded from PILs calculations both when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts.
- Supporting schedules and calculations identifying reconciling items
- Copies of most recent Federal and Provincial tax returns (non-utility tax items, if material, must be separated).
- Financial statements included with tax returns, if different from the financial statements filed in support of the application (see section 2.1.4).
- A calculation of tax credits (e.g., Apprenticeship Training Tax Credits, education tax credits). A Scientific Research and Experimental Development (SRED) return, if filed, may have confidential personal information (e.g. Social Insurance Number, address, hourly rate, etc.) of the people who are apprenticing. All such personal confidential information is not required and must be either removed or redacted from the filing. The unredacted version need not be filed.
- Supporting schedules, calculations and explanations for "other additions" and "other deductions" in the applicant's PILs model.

Taxes other than Income Taxes or PILs as defined in the APH (e.g. property taxes) should be included in Account 6105, effective January 1, 2012. An explanation of how these tax amounts are derived should be provided.

[6] Please see the Introduction (page 2) of this document.

2.4.5.1 Non-recoverable and Disallowed Expenses

There may be some distribution-only expenses incurred by a distributor that are deductible for general tax purposes, but for which recovery in 2016 distribution rates is partially or fully disallowed.

Where an expense incurred by a distributor is non-recoverable in the revenue requirement (e.g., certain charitable donations as discussed in section 2.4.3.7 above) or is disallowed for regulatory purposes, such a cost should also be excluded from the regulatory tax calculation.

2.4.5.2 Integrity Checks

The applicant must ensure the following integrity checks have been completed in its application and provide a statement to this effect, or an explanation if this is not the case:

- The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application
- The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historical, bridge and test years
- Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non-distribution tax amounts on Schedule 8.
- The CCA deductions in the application's PILs tax model for historical, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application
- Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application
- CCA is maximized even if there are tax loss carry-forwards
- A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized
- Accounting OPEB and pension amounts added back on Schedule 1 to reconcile accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations.
- The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.

2.4.6 Conservation and Demand Management

CDM activity is funded either through IESO-contracted Province-Wide CDM Programs or through OEB-approved CDM programs. Both of these approaches fund the programs through the global adjustment mechanism, and therefore costs directly attributable to these CDM programs (e.g., staff labour dedicated to such programs) must not be included in distribution rates.

2.4.6.1 Lost Revenue Adjustment Mechanism

The lost revenue adjustment mechanism (LRAM) is a retrospective adjustment designed to account for differences between the forecast revenue loss embedded in rates and the actual revenue loss due to the impacts of CDM programs promoted and executed by the distributor.

On April 26, 2012, the OEB issued updated CDM Guidelines. The CDM Guidelines provide more clarity on the CDM Code and what information needs to be filed in support of OEB-Approved CDM program applications, as well as to provide updated details on the legacy LRAM, and the LRAMVA for the 2011-2014 period.

2.4.6.2 LRAM for pre-2011 CDM activities

Per the OEB's CDM Guidelines and reinforced through the OEB's decisions in the 2012 and 2013 IRM process, distributors that have rebased commencing in 2010 are not eligible for LRAM claims for lost revenue associated with the persistence of legacy programs in 2010 and beyond unless the OEB explicitly stated its expectation in the distributor's last rebasing decision (or if it was explicitly stated in a settlement agreement) that the distributor may file a claim in the future. Furthermore, the OEB expects that any LRAM claims for the period prior to 2010 have been completed. Therefore, no LRAM claims are expected in 2014 or later cost of service applications.

2.4.6.3 LRAM Variance Account (LRAMVA)

For CDM programs delivered within the 2011 to 2014 period, the OEB established Account 1568 as the LRAMVA to capture the variance between the OEB-approved CDM forecast and the actual results at the customer rate class level. Accounting guidelines regarding the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the CDM Guidelines for further details.

The distributor shall compare the OEB-approved CDM adjustment to the load forecast, to the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

Distributors must continue to track the variances between the OEB-approved CDM adjustment to their load forecasts and the actual CDM results in the LRAMVA for the 2015-2020 period.

Disposition of the LRAMVA

At a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. Also, distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

In support of its application for lost revenues, distributors must file the following:

- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its lost revenue amount
- A statement indicating that the distributor has relied on the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation and a copy of this report
- Separate tables for each rate class showing the lost revenue amounts requested by the year they are associated with and the year the lost revenues took place. Within each separate rate class table, include a list of all the CDM programs/initiatives applicable to that rate class and provide the energy savings (kWh) and peak demand (kW) savings assigned to those programs/initiatives
- Lost revenue calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's OEB-approved variable distribution charge appropriate to the class
- A statement and, if applicable, a table that indicates whether carrying charges are being requested on the lost revenue amount
- For OEB-approved programs, a third party report, in accordance with the IESO's EM&V Protocols as set out in Section 6.1 of the CDM Code, that provides a review and verification of the distributor's lost revenue calculations, including:
    - Confirmation of the use of correct input assumptions and lost revenue calculations
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and by each customer class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested.

A separate third party review of the distributor's IESO-contracted Province-Wide CDM programs is not required.

2.5 Exhibit 5: Cost of Capital and Capital Structure

The OEB's general guidelines for cost of capital in rate regulation are currently provided in the *Report of the OEB on Cost of Capital for Ontario's Regulated Utilities* (the "2009 Report"), issued December 11, 2009.

The OEB issues the cost of capital parameter updates for cost of service applications. Distributors should use the most recent parameters as a placeholder, subject to an update if new parameters are available prior to the issuance of the OEB's decision for a specific distributor's application.

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 and supporting evidence for its proposal.

2.5.1 Capital Structure

The elements of the deemed capital structure are shown below and must be presented with the required schedules. Appendix 2-OA must be completed for the last OEB-approved and Test years. Appendix 2-OB must be completed for all required historical, bridge year and test years,

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

Any explanations of material changes in actual capital structure are required, including:

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

2.5.2 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 the cost for each capital component
- Profit or loss on redemption of debt and/or preference shares, if applicable
- Copies of any current promissory or demand notes or other debt arrangements with affiliates

- Explanation of the applicable debt rate for each existing debt instrument, including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report
- 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 will be affiliated or with a third party, expected term/maturity, any specific capital project(s) that the debt funding is for, etc.)
- If the applicant is proposing any rate that is different from the OEB guidelines, a justification of forecast costs by item, including key assumptions.

Notional Debt

The cost of debt is a frequently contested area in applications. Notional debt is that portion of the deemed debt that results from differences between the distributor's actual debt and the deemed debt of 60% debt (56% long-term debt and 4% short-term debt).

Notional debt can arise for a number of reasons such as the difference between actual capital assets and regulatory rate base due to the addition of the formulaic working capital allowance

Divergence from the deemed capital structure is generally under the control of the utility as it may relate to timing for debt financing for planned capital investments, as well as the interests of shareholders, such as reinvesting retained earnings.

Notional debt can be either positive (i.e. deemed debt is greater than actual debt) or negative (where deemed debt is less than actual debt). Since the factors which cause notional debt to arise are largely under the control of the utility, notional debt should attract the weighted average cost of actual long-term debt rate rather than the current deemed long-term debt rate issued by the OEB. This approach has been upheld in several decisions in recent years.[7]

The possible exception to this is that the deemed long-term debt rate should apply as a ceiling in a situation where a utility is 100% equity financed and has no current debt or recent history of debt financing.

[7] OPG's Prescribed Payments for 2011-12 Decision with Reasons EB-2010-0008, pages 124-125,
Hydro One Networks Inc. Decision with Reasons, EB-2008-0272, pages 51, 54-55,
Hydro One Remote Communities Decision with Reasons, EB-2008-0232, page 12,
London Hydro Inc. Decision with Reasons, EB-2008-0235, pages 36-37

2.5.3 Not-for-Profit Corporations

In prior OEB Decisions and Orders,[8] the OEB has determined that applicants that are not-for-profit corporations shall retain the revenue in excess of costs only for the purpose of meeting the applicant's need to build up appropriate operating and capital reserves based on applicant's forecast in the test year (the Reserve Requirement). The OEB has further stated that, once the appropriate limits for these reserves have been reached, it would expect applicants to submit an application seeking a rate adjustment to discontinue any further build-up.

An applicant that is a not-for-profit corporation must document and provide the following as a part of its application:

- The applicant shall provide the detailed calculation for its test year revenue requirement based on its Reserve Requirement. The applicant's revenue requirement shall equal to the sum of all costs plus the annual incremental amounts needed for building up the proposed reserves.
- The proposed reserves (operating, capital, insurance, etc.), the rationale for the need to establish each reserve, the time period of building up the reserves, and the procedure and policy of each reserve. The policy and procedure of each reserve should include the following information:
  - The definition of each reserve
  - The purpose, goals and intended use of each reserve
  - The capped amounts of each reserve and the methodology used to derive such amounts
  - The mechanism and the process to build, use and maintain the reserves.
- A description of the applicant's governance of the not-for-profit corporation, including the following:
  - Policy on reserve requirement
  - The roles and responsibilities of the applicant's Board of Directors and management with regards to the need for types of reserve funds, and establishing and preserving the amounts for each types of reserves
  - The authorization and approval process for access and use of the reserves
  - Investment objectives and policies for the reserve funds
  - Reporting requirements and monitoring.
- If the applicant has approved reserves from previous OEB decisions, the applicant must document the following:

[8] Attawapiskat Power Corporation 2006 cost of service Decision and Order EB-2005-0233; Five Nations Energy Inc. 2010 cost of service Decision and Order EB-2009-0387

- Any changes to the reserve policies and rationale for the changes since the applicant's last cost of service application
- The limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits
- The current balances of any established capital and/or operating reserves
- Any withdrawals from established capital and operating reserves, identifying the amounts withdrawn and purposes that the funds were used for
- If the limits on established capital and operating reserves have been achieved, the applicant's proposal for the utilization of amounts, increases in the limits (if supported by growth and/or changes in business conditions and risk), refunding of amounts in excess of the limits or other rate adjustments so that the established limits will not be exceeded
- If the limits on the established reserves were not achieved, the applicant's proposed reserves for the test year should be set lower than the reserve levels requested in its last cost of service rate application. The applicant should provide the rationale and the detail for its forecast of the Reserve Requirement for the test year.

2.6 Exhibit 6: Calculation of Revenue Deficiency or Sufficiency

The applicant must include the following information in this exhibit, excluding energy costs (i.e. cost of power and associated 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
- Gross Deficiency or Sufficiency in Revenue.

The filing requirements have been designed in a manner to isolate the delivery-related deficiency/sufficiency separate and apart from the energy-related deficiency/sufficiency. In keeping with this separation, the applicant must provide revenue deficiency or sufficiency calculations net of electricity price differentials captured in the RSVAs and also net of any cost associated with LV charges or DVA balances of smart meter expenditures/revenues being tracked through variance accounts and for which disposition is not being sought in the application.

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

The impacts of any change in methodologies (e,g., accounting standards or policies) must be provided on the overall deficiency/sufficiency and on the individual cost drivers contributing to it.

2.6.1 Revenue Requirement Work Form

Since 2009, the OEB has required a Revenue Requirement Work Form ("RRWF") to be filed as part of a cost of service application. The RRWF is a live Microsoft Excel spreadsheet issued by the OEB along with these filing requirements that, based on key data inputs for capital and operating costs, revenues, taxes and tax rates, and cost of capital parameters, provides a high-level summary of the numbers in the application. It links the revenue requirement and the revenue deficiency/sufficiency to the test year rate base, and capital and operating costs.

The RRWF also serves as a check that the calculations employed in the detailed models and spreadsheets conform with established practice for cost of service rate regulation and that all calculations and approaches are internally consistent.

The RRWF serves as a summary of the changes to the proposed revenue requirement through the stages of application processing. Applicants should also be mindful that a new page "Summary of Proposed Changes" (Sheet 10. Tracking Changes), summarizing cumulative changes to key results of the application was added for 2015. This sheet must be completed and kept updated during the course of the application review process.

Applicants should refer to the final RRWF reflecting the OEB's Decision and Rate Order in their last cost of service application for OEB-approved numbers.

The RRWF must be filed in this exhibit in pdf along with a live Microsoft Excel version. The revenue requirement components in the application and the resulting revenue deficiency/sufficiency in this exhibit must correspond with the calculations in the RRWF. Applicants must ensure that numbers entered in the RRWF are reconciled with the appropriate numbers in other exhibits.

2.7 Exhibit 7: Cost Allocation

The following areas are discussed in this exhibit:

1) Cost Allocation Study Requirements
2) Class Revenue Requirements
3) Revenue-to-Cost Ratios.

2.7.1 Cost Allocation Study Requirements

The OEB has outlined its cost allocation policies in the OEB's reports of November 28, 2007 *Application of Cost Allocation for Electricity Distributors*, and March 31, 2011 *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) (the "Cost Allocation Reports").

A completed cost allocation study using the OEB-approved methodology or a comparable model must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Microsoft Excel spreadsheets. The most current update of the model (version 3.2) is available on the OEB's web site. Appendix 2-P must also be completed.

For any customer class for which updated load profiles are not available, the load profiles provided by Hydro One for use in the Informational Filing may be used - scaled to match the load forecast as it relates to the respective rate classes (see section 2.3.2 above). This will be necessary 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 Test Year load forecast. In the case where a new customer class is being created, the applicant must explain the basis for the class load profile and ensure consistency with the load forecast information per section 2.3.2.

Distributors should refer to section 2.6.4 of the March 31, 2011 Cost Allocation Report concerning weighting factors for allocation of certain costs. A description of the weighting factors is required. Distributors are expected to develop their own weighting factors. As explained in the report, if the distributor has chosen to use the default weighting factors, an explanation must be provided.

If using the OEB-issued model, the distributor must file a hard copy of input sheets I-6 and I-8, and output sheets O-1 and O-2 (first page only). Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information. A complete hard copy of the cost allocation model is not required, but the distributor must file a complete live Microsoft Excel cost allocation model with the application.

Large General Service and Large Use Classes

As a reminder, the treatment of the Transformer Ownership Allowance has been revised in the current version of the cost allocation model, as compared to the version that the distributor would have used in a previous re-basing application.

Embedded Distributor Class

Any distributor that is the host to one or more distributors must provide the following information, as applicable:

- Evidence that the host distributor has consulted with its embedded distributor(s) prior to preparing its cost allocation model and filing its rate application, and a statement as to whether or not the embedded distributor(s) support(s) the host distributor's approach to the allocation of costs to the embedded distributor(s).
- If the host has a separate rate class for its embedded distributor(s), the host distributor must include the class as such in its cost allocation study and in Appendix 2-P.
- If the host proposes to establish a new embedded distributor class, the host distributor must include the class as such in its cost allocation study and in Appendix 2-P and provide rationale and supporting evidence for the establishment of an Embedded Distributor class, as applicable. The host must provide the costs of serving the embedded distributors, load served, information regarding ownership of relevant assets involved in the connection(s), whether assets are dedicated to the embedded distributor(s) or shared to serve other customers, and the distribution charges levied.
- If the host distributor proposes to bill the embedded distributor(s) as if it/they were General Service Class customers, the costs and revenue must be included with that class in the cost allocation study and Appendix 2-P. In this case, the host distributor must also complete Appendix 2-Q which shows details on how much of the host's facilities are required to serve the embedded distributor(s), regardless of the fact that they are not treated as a distinct rate class elsewhere. The host must provide the cost of serving the embedded distributors, load served, information regarding ownership of relevant assets involved in the connection(s), and the distribution charges levied. Additionally, the host distributor must provide evidence supporting the continued appropriateness of the rates for the general service class for recovering the costs of providing low voltage distribution services to the embedded distributor(s).

Unmetered Loads (Including Street Lighting)

On December 19, 2013, the OEB issued its EB-2012-0383 *Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads*. This report arose from the OEB's statement in the 2011 Cost Allocation Report that cost allocation issues related to unmetered loads (i.e. street lighting, sentinel lighting, and unmetered scattered load) would be best addressed in a separate consultation process. Following the issuance of this report, the OEB issued a *Distribution System Code* amendment on May 15, 2014 amending section 2.4.6 to require distributors to include certain minimum requirements in their Conditions of Service in relation to unmetered load customers. These amendments came into force on January 1, 2015, and therefore distributors should have performed the necessary updates during 2014.

The OEB expects distributors to communicate with unmetered load customers, including street lighting customers, to assist them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers. Such communication should take place when proposing changes to the level of the rates and charges or the introduction of new rates and charges.

On June 12, 2015, the OEB issued a letter outlining its new cost allocation policy for the street lighting rate class. A new “street lighting adjustment factor” will be used to allocate costs to the street lighting rate class for primary and line transformer assets. The “street lighting adjustment factor” replaces the ‘number of connections’ allocator. The cost allocation model has been updated to reflect the street lighting adjustment factor.

microFIT class

The OEB does not expect a distributor to include microFIT as a separate class in the cost allocation model in 2016. The model will produce a calculation of unit costs which the OEB will use to update the uniform microFIT rate at a future date. Unlike other classes, the cost information is not used to establish a separate class revenue requirement for the microFIT class.

Standby Rates

Standby Charges are charged by a distributor to a customer with load displacement facilities behind its meter to address the fact that the customer is dependent on the distributor for its entire electricity supply when the load displacement facility is out of service. The charges compensate a distributor for the cost of maintaining the ability to accommodate the total load of a customer at any time. The recovery of costs associated with the distributor’s facilities that must be available to meet the customer’s total demand must not inadvertently subsidize the rest of the distributor’s customers while ensuring that the customer with load displacement is not unduly burdened by higher than reasonable charges.

Standby rates have been approved on an interim basis since 2006. The rates have been approved in rate applications taking into account the circumstances of the distributor and its customers to which these rates apply.

Distributors may seek approval of standby charges on a final basis, but must provide evidence confirming that they have advised all affected customers of the proposal.

A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based may do so, but must provide full documentation supporting its proposal, in addition to confirming that all affected customers have been notified of the proposed change(s).

New Customer Class(es)

If the distributor is establishing a new customer class, the rationale for doing so is required. Further, information provided in the distributor's previous cost of service application concerning class revenue requirements must be restated in Appendix 2-P on the basis of the proposed customer classes, to provide continuity with the proposed customer classes in the current application.

Eliminated Customer Class(es)

If the distributor is proposing to eliminate or combine existing customer classes the distributor must identify such proposals and the supporting rationale. To the extent possible, the distributor must restate information from its previous cost of service application concerning class revenue requirements in Appendix 2-P, on the basis of the proposed customer classes to provide continuity of information.

2.7.2 Class Revenue Requirements

Appendix 2-P shows the format for filing cost allocation information and includes four tables.

The first table in Appendix 2-P is a format for showing the test year class revenue requirements, which is produced in output sheet O-1 of the OEB model. This table also includes a comparison to the most recent study previously filed with the OEB.

The OEB has established ranges for revenue-to-cost ratios. Rate rebalancing is the process of changing rates by different percentage amounts for different customer rate classes to more appropriately reflect the mix of customers and the costs of assets and operating costs to service customers in each class. To support a proposal to rebalance rates, the distributor must provide information on the revenue by class 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 distributor.

The second table in Appendix 2-P shows three revenue scenarios, by rate class. Each scenario is based on the forecast of class billing quantities. The scenarios are, respectively, the forecast quantities multiplied by: a) existing rates; b) prorated existing rates that would yield the test year Base Revenue Requirement; and c) proposed class revenues. The table also shows the allocation of Miscellaneous Revenue to the rate classes, which is an output from the cost allocation model.

2.7.3 Revenue-to-Cost Ratios

The range of acceptable ratios is in the OEB's March 31, 2011 Report, on Cost Allocation, section 2.9.4.

Per the OEB's June 12, 2015 letter, the OEB has narrowed the revenue to cost ratio policy range for the street lighting rate class from 70-120% to 80-120% consistent with views expressed in the *Report of the Board: Review of Cost Allocation for Unmetered Loads*.

The third table in Appendix 2-P combines information from the previous two tables in the form of revenue-to-cost ratios and includes the following information for each class:

- The previously approved ratios most recently implemented by the distributor
- 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, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model
- The ratios that are proposed for the test year

Results flowing from the updated cost allocation model may show some ratios being outside of the OEB-approved ranges. In these cases, distributors must ensure that their cost allocation proposals include adjustments to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rate burden of any particular class or classes is significant.

If the distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided. The fourth table in Appendix 2-P provides a format for presentation of such information. In particular, if the proposed ratios are outside the OEB's policy range in the test year, the distributor must show the proposed ratios in subsequent years that would move the ratios to within the policy range.

If using a cost allocation model other than the OEB model, the distributor must ensure that costs exclude LV costs, and deferral and variance accounts such as Smart Meter costs and that revenues exclude rate riders, rate adders and the Smart Metering Entity charge. The distributor must also ensure that information relevant to microFIT unit costs and revenue is consistent with the output from the OEB's model.

2.8 Exhibit 8: Rate Design

The following areas are discussed in this exhibit:

- Fixed/Variable Proportion
- Rate Design Policy Consultation
- Retail Transmission Service Rates (RTSRs)
- Retail Service Charges
- Wholesale Market Service Rate
- Smart Metering Charge
- Specific Service Charges
- Low Voltage Service Rates (where applicable)
- Loss Adjustment Factors
- Tariff of Rates and Charges
- Revenue Reconciliation
- Bill Impact Information
- Rate Mitigation (where applicable).

Please note that monthly fixed charges must be shown to two decimal places while variable charges must be shown to four places. Distributors wishing to depart from this approach must provide a full explanation as to why they believe it is necessary and appropriate.

2.8.1 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
- A table comparing current and proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study.

Calculations of fixed/variable proportions should use the billing determinants from the proposed load forecast as the basis of the calculation.

If a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling for any non-residential class.
The fixed/variable analysis must be net of (i.e. exclude) rate adders, funding adders and rate riders (i.e. Low Voltage, smart meter rate riders, GEA and smart grid rate riders, deferral/variance account disposition, etc.).

2.8.2 Rate Design Policy

On April 2, 2015, the OEB released its *Board Policy: A New Distribution Rate Design for Residential Electricity Customers* (EB-2014-0210), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. This will be implemented over a period of four years, beginning in 2016. The approach to implementation of the policy, including mitigation expectations, was described in a letter from the OEB published on July 16, 2015.

Distributors are expected to propose changes to residential rates consistent with this policy, while also taking into account matters such as mitigating bill impacts for customers. Due to timing, distributors that have filed cost of service applications in the first half of 2015 for January 1, 2016 rates may request an exception for 2016 and propose a transition beginning with 2017 rates. All other applicants are expected to file proposals to implement this policy.

In proposing a transition to a fully-fixed monthly service charge, the distributor must follow the approach set out in Appendix 2-PA. Generally speaking, distributors must propose a fully fixed rate design for charges applicable to the residential class provided that those charges are specifically related to the distribution of electricity.[9]

Pass-through costs (e.g. transmission rates, low-voltage service rates, and Group 1 DVAs) and LRAMVA amounts are to continue to be recovered as variable charges because they predominantly relate to energy charges. The rate design change for distributor-specific charges is effective going forward for new charges (e.g. rate riders). Distribution-specific charges (or rate riders) already on a distributor's tariff should remain unchanged until they expire.

Distributors with a seasonal residential class must propose identical rate design treatment for such a class.

[9] Examples of distribution-specific charges include: Group 2 Deferral and Variance Accounts including balances in accounts 1575/1576, ACM and ICM rate riders.

2.8.3 Retail Transmission Service Rates ("RTSRs")

In preparing its application, the distributor must reference the OEB's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates,* June 28, 2012, and subsequent updates to the Uniform Transmission Rates (UTRs). A completed version of the RTSR model must be filed in pdf and live Microsoft Excel formats.

The distributor must ensure that the information provided in this section is consistent with that provided in the working capital allowance calculation provided in Section 2.2.1.3, as it relates to rates such as RTSRs, or provide explanations for any differences.

2.8.4 Retail Service Charges

Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity as set out in the *Retail Settlement Code*. Distributors should note that the current retail service rates and charges were established on a generic basis. The OEB expects distributors proposing changes to the level of the rates and charges, or the introduction of new rates and charges, to provide evidence that they have consulted with retailers about the changes and have provided them with adequate notice of such changes.

Distributors must maintain the appropriate Retail Service Costs Variance Accounts (RCVAs) to record the difference between charges levied on customers and retailers, and the direct incremental costs for the provision of these services. The RCVAs are discussed further in section 2.9.6.

2.8.5 Wholesale Market Service Rate

The Wholesale Market Service Rate is designed to allow distributors to recover costs charged by the Independent Electricity System Operator ("IESO") for the operation of the IESO-administered markets and the operation of the IESO-controlled grid.

The Wholesale Market Service Rate is an energy based rate (per kWh). This rate applies to those customers of a distributor who are not wholesale market participants. An embedded distributor who is not a wholesale market participant would be treated as a customer to the host distributor and would be charged the Wholesale Market Service Rate.

This rate is set by the OEB on a generic (i.e., Province-wide) basis. Distributors wishing to apply for a rate other than the generic rate set by the OEB must provide justification as to why their specific circumstances would warrant such a different rate, in addition to a detailed derivation of their proposed rate.

On December 19, 2014, the OEB issued a Decision with Reasons and Rate Order (EB-2014-0347) establishing that the Wholesale Market Service Rate used by rate-regulated distributors to bill their customers would continue to be $0.0044 per kilowatt hour effective January 1, 2015 and that the rate for rural and remote rate protection (RRRP) would continue to be $0.0013 per kilowatt hour, effective January 1, 2015. Distributors should reflect a total charge of $0.0057 per kilowatt hour in their applications.

2.8.6 Smart Metering Charge

On March 28, 2013, the OEB issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers effective May 1, 2013. Distributors should continue to reflect this charge in their applications. The Smart Metering charge is currently in effect until October 31, 2018.

2.8.7 Specific Service Charges

A distributor must describe the purpose of each new or revised specific service charge for which it is seeking approval. Distributors must specify which charges are new and for which existing charges they are proposing changes. Distributors must separately identify in the Executive Summary all proposed changes in the application that will have a material impact on customers, including any changes to other rates and charges that may affect discrete customer groups. Applicants must also identify the specific customers or customer groups that will be impacted by each such proposal.

Distributors requesting either a new specific service charge or a change to the level of an existing charge should describe the purpose of such charges, or the reason for the proposed change to an existing charge and provide calculations supporting the determination of each new or revised charge including the following elements:

- Direct labour (internal and/or external)
- Labour rate (internal and/or external)
- Burden rate
- Incidental (e.g. postage for mail)
- Vehicle time and rate (if applicable).

Distributors must also identify any rates and charges that are included in their Conditions of Service but do not appear on the OEB-approved tariff sheet, and an explanation for the nature of the costs being recovered must be provided. A schedule outlining the revenues or capital contributions recovered from these rates and charges from 2011 to 2014 and the revenue or capital contributions forecasted for the 2015 bridge and 2016 test years must also be provided, as well as a proposal and explanation on whether these rates and charges should be included on the applicant's tariff sheet.

Distributors must ensure that the revenue from the total of the proposed specific service charges corresponds with the evidence under Operating Revenues (see section 2.3.3).

On April 15, 2015, the OEB announced proposed amendments to the Distribution System Code that will require all distributors to implement a monthly bill for all customers by December 31, 2016.Distributors should provide details of their plan for this transition if they are not already on monthly billing. .

2.8.8 Low Voltage Service Rates (where applicable)

If the distributor is (fully or partially) embedded (see section 21.7) the distributor must provide the following information:

- Forecast of LV cost, which is the sum of host distributors' charges to the applicant
- Actual LV costs for the last three historical years, along with bridge and test year forecasts. The distributor must also provide the year-over-year variances, and explanations for substantive changes in the costs over time, up to and including the test Year forecast
- Support for the forecast of LV costs: forecast volumes and actual or forecast host distributor(s) LV rates. For example, an applicant distributor whose host distributor is Hydro One would include the distributor's costs for Sub-Transmission lines, plus a Sub-Transmission service charge, plus any other charges such as facility charges for connection to a shared distribution station that apply to the embedded distributor's monthly bill from the host distributor, together with the applicable charge determinants
- Allocation of forecast LV cost to customer classes (generally in proportion to Transmission Connection Rate revenues)
- Proposed LV rates by customer class to reflect these costs.

2.8.9 Loss Adjustment Factors

The distributor must document the proposed Supply Facilities Loss Factor (SFLF), distribution and total loss factors for the test year.

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

- A statement as to whether the distributor is embedded, including whether it is fully or partially embedded.

- Details of loss studies and recommendations, if required by a previous OEB decision.
- Calculations showing the losses in previous years. A minimum of three years of historical data is required, although five years of historical data is preferred.
- A completed Appendix 2-R showing the energy delivered to the distributor with and without losses.
- Explanation of distribution losses greater than 5%.
- If the proposed distribution loss factor is greater than 5%, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward.
- Explanation of the derivation of the SFLF, including reasons for any differences from the standard SFLFs referenced in Appendix 2-R, Row H.

2.8.10 Tariff of Rates and Charges

The distributor must provide the current and proposed tariff of rates and charges. Distributors must ensure that each proposed change is explained and supported in the appropriate section of the application. Distributors must file the new Tariff of Rates and Charges appendix (Appendix 2-Z).

The distributor must provide an explanation of changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates. Distributors may only charge rates that have been approved by order of the OEB. Distributors must explain and justify any changes to the terms and conditions of service in the Tariff of Rates and Charges that would affect the application of their rates.

2.8.11 Revenue Reconciliation

For the proposed tariff of rates and charges, the following information must be provided:

- 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.).

The applicant must provide a completed Appendix 2-V. The purpose of Appendix 2-V is to check that the test year demand, and the proposed rates recover the proposed costs (in the form of the revenue requirement) to serve the forecasted customers and demand/consumption, subject to rounding. Rates and charges input on Appendix 2-V should be rounded to the same number of decimal places as shown on the proposed Tariff of Rates and Charges.

2.8.12 Bill Impact Information

Appendix 2-W must be filed for all classes. This appendix identifies existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass-through costs – "Sub-Total A", % change in distribution – "Sub-Total B", % change in delivery – "Sub-Total C", and % change in total bill).

The distributor must provide the impact of changes resulting from the as-filed application on representative samples of end-users, i.e., volume, percentage rate change and revenue. The distributor must include the base distribution rates, any applicable rate adders or rate riders, and RTSRs. Commodity rates and regulatory charges should be held constant.

Rates and charges input on Appendix 2-W should be rounded to the decimal places as shown on the existing and proposed Tariff of Rates and Charges.

The bill comparisons must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided in Appendix 2-W.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

2.8.13 Rate Mitigation

In the RRFE report the OEB concluded that it will maintain its current policy on rate mitigation. The OEB stated that the implementation of the renewed regulatory framework makes the need for mitigation of large rate increases less likely as controls to address cost increases are integrated into the planning and rate-setting processes, and each distributor will be able to choose the rate-setting approach that best suits its particular investment profile.

The OEB further stated that it would expect distributors to consider total bill increases when they engage in planning, an exercise that will be facilitated under the integrated approach to network planning described in Chapter 5 and to demonstrate to the extent possible the responsiveness of their planned capital and OM&A expenditures to the need for reasonably stable and affordable rates for customers.

Starting in 2016, distributors will begin to shift rate design for residential customers toward fully fixed rates. This change introduces some new considerations for the issue of mitigation.

As discussed above, at 2.8.2, distributors will be expected to implement the change in equal increments over a four-year period. In the event that the monthly service charge would have to rise more than $4 per year in order to effect this change, distributors shall apply to extend the transition period. It is expected that in most cases, only a fifth transition year would be required to make the changes within the $4 impact threshold identified in the policy. A distributor shall propose an alternative or additional strategy in the event that an additional transition year is insufficient. Consistent with OEB policy regarding mitigation, a distributor may propose as part of its application that no extension is necessary; such a position must be substantiated with reasons.

The new rate design is revenue neutral across the residential class, but the impact on individual customers will vary with consumption. The OEB has established that, when assessing the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, a utility shall evaluate the total bill impact for a residential customer at the distributor's 10th consumption percentile.[10] In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis. Sorting or segmentation of residential class data by consumption level will be required. Distributors must provide a description of the method they used to derive the 10^{th} consumption percentile. The description should include a discussion regarding the nature of the data that was used (e.g. was the source data for all residential customers or a representative sample of residential customers).

If the impact for these customers is 10% or greater, a distributor must file a plan to mitigate the impact for the whole residential class or indicate why such a plan is not required. The distributor will have the ability to propose the approach to mitigation, including, but not limited to, the option to extend the transition to fixed rates over a longer period. A detailed rationale must be provided. Where the evaluation of bill impacts indicates that rate mitigation is only required for the residential class, it is the OEB's expectation that distributors will propose mitigation strategies that target only the residential class and that any associated cost consequences of any revenue deferral (e.g. additional carrying charges due to longer dispositions periods for DVAs) will be borne by that class.

2.8.13.1 Mitigation Plan Approaches

A distributor must file a mitigation plan if total bill increases for any customer class exceed 10%. The mitigation plan must include the following information:

- A specification of all customer classes or groups of customers that were initially identified as having increases in excess of 10% and the magnitude of these increases.

[10] To a minimum of 50 kWh per month.

- A detailed description of any mitigation measures undertaken, e.g. reductions to the revenue requirement, inter -class shifts, or longer disposition periods for deferral and variance account balances.
- A justification for all mitigation measures proposed, including reasons if no mitigation is proposed.
- Revised impact calculations in Appendix 2-W reflecting the mitigation plan.
- Any other information the distributor believes is relevant to its mitigation proposal.

The distributor must ensure that Appendix 2-W reflects any mitigation plan proposed in the application.

The bill comparisons must assume a constant commodity price and other rates, despite potential changes such as changes in the commodity price and other rates that may or may not be known at the time of an application.

If a distributor determines, in the course of the development of its mitigation plan, that there is no suitable manner in which to resolve the bill increases exceeding the mitigation threshold, such a determination must be stipulated in the mitigation plan and supported with sufficient rationale.

2.8.13.2 Rate Harmonization Mitigation Issues

Distributors which have merged or amalgamated service areas, and which have not yet fully harmonized the rates between or among the affected distribution service areas, must file a rate harmonization plan. The plan must include a detailed explanation and justification for the implementation plan, and an impact analysis.

In the event that the combined impact of the cost of service based rate increases and harmonization effects result in total bill increases for any customer class exceeding 10%, the distributor must include a discussion of proposed measures to mitigate any such increases in its mitigation plan discussed in section 2.8.13 above, or provide a justification as to why a mitigation plan is not required.

A migration to fully harmonized rates that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR period.

2.9 Exhibit 9: 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 in this application:

- List of all outstanding deferral and variance accounts and sub-accounts. The applicant must provide a brief description of any account that the applicant may have used differently than as described in the APH.
- A continuity schedule for the period from the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances. A completed version of the DVA continuity schedule, available on the OEB's web site, must be filed in live Microsoft Excel format.
- 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. These rates are provided on the OEB's website. The most recent posted interest rate is used for any future periods until updated by the OEB.
- Explanation if the account balances in the continuity schedule differ from the account balances in the trial balance reported through the *Electricity Reporting and Record-keeping Requirements* and documented in the applicant's Audited Financial Statements.
- Identification of which Group 2 accounts the distributor will continue and which will be discontinued on a going-forward basis, with an explanation for these proposals.
- Statement as to any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account. This must correspond with information provided in Exhibit 1 (see section 2.1.2).
- A statement as to whether or not the applicant has made any adjustments to deferral and variance account balances that were previously approved by the OEB on a final basis in both cost of service and IRM proceedings (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding). If this is the case, the applicant must provide explanations for the nature and amounts of the adjustments and include supporting documentation, under a section titled "Adjustments to Deferral and Variance Accounts".
- A breakdown of energy sales and cost of power expense balances, as reported in the audited financial statements by distributors, mapped to USoA account numbers. The distributor must reconcile these numbers to the audited financial statements. If there is a difference between the energy sales and cost of power expense reported numbers, the distributor must explain why it is making a profit or loss on the commodity.
- A statement confirming that the distributor pro-rates the IESO Global Adjustment Charge into RPP and non-RPP portions. If this is not the case, the distributor must provide an explanation.

2.9.1 PILs and Tax Variances for 2006 and Subsequent Years - Account 1592

If the distributor has not already filed for and been approved disposition in a prior rates application, the OEB expects distributors to file for disposition of account 1592 in their cost of service applications. Distributors must complete and file Appendix 2-TA in support of their request to dispose of the account 1592 balance.

2.9.2 Harmonized Sales Tax Deferral Account

During the 2010 IRM application process, the OEB directed electricity distributors to record in deferral account 1592 (PILs and Tax Variances for 2006 and subsequent years, Sub-account HST/OVAT ITCs), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

In December 2010, as part of its Frequently Asked Questions on the *Accounting Procedures Handbook for Electricity Distributors*, the OEB provided accounting guidance on this matter and provided a simplified approach designed to facilitate administrative cost-saving opportunities. Distributors filing for disposition of this sub-account in their cost of service applications should review this material.

No more amounts should be recorded in Account 1592 (PILs and Tax Variances for 2006 and subsequent years, Sub-account HST/OVAT ITCs for the test year and going forward), as the impact of the HST and associated ITCs on capital and operating costs in the test year must be reflected in the applied-for revenue requirement. For the 2016 test year for example, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to December 31, 2015 since the test year, which starts January 1, 2016 would include the HST impacts in rates going forward. If the test year's rate year begins May 1, 2016, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to April 30, 2016.

The distributor must provide an analysis that supports the distributor's conformity with December 2010 APH FAQs, in particular the example shown in FAQ # 4.

Appendix 2-TB should be completed if applicable.

Most distributors have cleared the balance in this sub-account; therefore this section is only expected to be relevant to a few distributors.

2.9.3 One-time Incremental IFRS Costs

An applicant should file a request for review and disposition of the balance in Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance. The balance requested should include actual audited incremental transition costs to date, the unaudited actuals for the bridge year and a forecast of any remaining costs to be incurred for the test year. Given that applicants are expected to adopt IFRS effective January 1, 2015, costs forecasted to be incurred in the bridge year and 2016 test year are expected to be minimal.

An applicant must file a completed Appendix 2-U and must:

- File for disposition of the balance in Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance reflecting the difference between the amounts recovered in rates and the actual incurred one-time administrative incremental IFRS transition costs. Any one-time administrative incremental IFRS transition costs already included for recovery in rates must be included as credits on a separate line in Appendix 2-U.
- Provide a statement as to whether any one-time administrative incremental IFRS transition costs are embedded in the proposed 2016 revenue requirement. If this is the case, the applicant must state the section of the proposed 2016 revenue requirement that includes these costs, the quantum and explain why it is included in the 2016 revenue requirement instead of the Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.
- Provide explanations for each category of costs recorded in the Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account. The applicant must explain how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.
- Provide explanations for material variances that may be recorded in the Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance account.
- Per the October 2009 APH FAQ #3 regarding costs that are permitted to be recorded in the Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account and Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account, the applicant must provide a confirmation statement that no capital costs, ongoing IFRS compliance costs, or impacts arising from adopting accounting policy changes are recorded in Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account. If this is not the case, the applicant must provide an explanation.

2.9.4 Account 1575, IFRS-CGAAP Transitional PP&E Amounts

Account 1575 will apply to an applicant that files a 2016 cost of service application on the basis of MIFRS. For an applicant filing based on MIFRS, Account 1575 must capture all PP&E accounting changes made on transition to IFRS, with the exception of those related to capitalization and depreciation that are captured in Account 1576.

Deferral Account 1575 and variance Account 1576 cannot be used interchangeably and the applicant must follow the required accounting treatment applicable under each account. The accounting changes applicable to Account 1576 are not applicable to Account 1575 in relation to “changeover date” accounting on the applicant’s adoption of IFRS. Depending on the date the applicant implemented capitalization and depreciation policy changes and the date the applicant adopts IFRS, applicants are typically expected to have balances in Account 1576 as a result of the OEB mandated capitalization and depreciation policy changes under CGAAP as referenced in 2.9.5 below. Applicants may also have balances recorded in Account 1575 for any further PP&E accounting changes made on transition to IFRS.

Per its letter dated June 25, 2013, effective for the 2014 cost of service rate applications and subsequent rate years, the OEB will require the use of a separate rider for the disposition of the balance in Account 1575.

Applicants must provide the following:

- A breakdown of the balance related to the IFRS-CGAAP Transitional PP&E Amount that is effective on the transition date to MIFRS. The applicant must provide the supporting analysis of the amounts in this account by completing Appendix 2-EA.
- A listing and quantification of the drivers of the change in closing net PP&E (CGAAP versus MIFRS). The Fixed Asset Continuity Schedule (Appendix 2-BA) in the rate application must not be adjusted for balances related to the IFRS-CGAAP Transitional PP&E Amount. The applicant must show that the application of the accounting policies change is applied on a prospective basis in the year in which the accounting changes occurred (e.g., 2014).
- A breakdown for quantification of any accounting changes arising from the transition to IFRS in relation to PP&E (e.g. customer contributions, asset retirement obligations, interest capitalization, etc.), including an explanation for each of the accounting changes made by the applicant.
- A separate volumetric rate rider for Account 1575 for the clearance of the account balance over the proposed disposition period, including all calculations showing its derivation. The applicant must show that the rate rider is comprised of the amortized amount of the account balance over the number of years proposed for the disposition period (e.g. five years);
- A rate of return component (i.e., weighted average cost of capital) to be applied to the balance of Account 1575, including all calculations showing its derivation.

The rate of return amount must be amortized over the number of years proposed for the disposition period (e.g. five years) and added together with the account balance amortized amount for inclusion in the Account 1575 rate rider. The amount for the return component must not be recorded in Account 1575.

- A statement confirming that no carrying charges are applied to the balance in the account.
- An explanation for the basis of the proposed disposition period of the Account 1575 rate rider. The OEB's determination of the disposition period will be on a case-by-case basis and will be guided primarily by such considerations as bill impacts and the financial impact on applicants.
- The balance of the account in the DVA Continuity Schedule.

2.9.5 Account 1576, Accounting Changes Under CGAAP

Applicants will use Account 1576 to record the financial differences arising as a result of changes to accounting depreciation or capitalization policies permitted by the OEB under CGAAP in 2012 or as mandated by the OEB in 2013.

For the typical applicant that files a 2016 test year application under MIFRS and made the changes to capitalization or depreciation policies by January 1, 2013 under CGAAP, the applicant must file with the OEB a request to clear Account 1576 for these changes as part of the cost of service application.

Per its letter dated June 25, 2013, effective for the 2014 cost of service rate applications and subsequent rate years, the OEB will require a rate of return component to be applied to the balance in Account 1576 and require the use of a separate rider for the disposition of the balance in Account 1576.

- For accounting changes made effective January 1, 2012, Account 1576 will capture the accounting changes made in 2012 under CGAAP. The applicant must reflect the updated accounting policies, as applicable, for each of the Historical years (2012, 2013 and 2014), or
- For accounting changes made effective January 1, 2013, Account 1576 will capture the accounting changes made in 2013 under CGAAP. The applicant must reflect the updated accounting policies, as applicable, for each of the Historical years (2013 and 2014).

Applicants must provide the following:

- The Fixed Asset Continuity Schedule (Appendix 2-BA) in the rate application, which must not be adjusted for balances related to Account 1576. The applicant must show that the accounting policies change is applied on a prospective basis in the year in which the accounting changes occurred (e.g. 2013).

- A breakdown of the balance related to Account 1576. The applicant must provide the supporting analysis of the amounts in this account by completing Appendices 2-EB or 2-EC. The drivers of the change in closing net PP&E (former policies under CGAAP versus revised policies under CGAAP) must be identified and quantified.
- A separate volumetric rate rider for Account 1576 for the clearance of the account balance over the proposed disposition period, including all calculations showing its derivation. The applicant must show that the rate rider is comprised of the amortized amount of account balance over the number of years proposed for the disposition period (e.g. five years);
- A rate of return component (i.e., weighted average cost of capital) to be applied to the balance of Account 1576, including all calculations showing its derivation. The rate of return amount must be amortized over the number of years proposed for the disposition period (e.g. five years) and added together with the account balance amortized amount for inclusion in the Account 1576 rate rider. The amount for the return component must not be recorded in Account 1576.
- A statement confirming that no carrying charges are applied to the balance in the account.
- An explanation for the basis of the proposed disposition period to clear the account balance through the Account 1576 rate rider. The OEB's determination of the disposition period will be on a case-by-case basis and will be guided primarily by such considerations as bill impacts and the financial impact on distributors.
- The balance of the account in the DVA Continuity Schedule.

2.9.6 Retail Service Charges

If the distributor has material debit or credit balances in Account 1518 RCVA Retail or Account 1548 RCVA STR, the distributor must:

- Confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services.
- Identify the drivers for the balances in Account 1518 and/or Account 1548.
- Provide a schedule identifying all revenues and expenses listed by USoA account number that are incorporated into the variances recorded in Account 1518 and/or Account 1548 for 2014, the actual/forecast for 2015 and a forecast for 2016.
- State whether or not the distributor has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. The distributor must provide an explanation and quantify the variance if the distributor has not followed Article 490.

If the distributor has zero balances in Account 1518 RCVA Retail or Account 1548 RCVA STR, the distributor must state whether or not it has followed Article 490, Retail Services and Settlement Variances of the *Accounting Procedures Handbook* for these accounts. The distributor must provide an explanation and quantify the variance if Article 490 has not been followed.

2.9.7 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.
- Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements and provide explanations for any variances.
- Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's RRR filings for each account.
- Provide explanations, even if such variances are below the 5% threshold, if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior OEB decisions, and prior period adjustments); and/or (2) the cumulative effect of immaterial differences over several accounts total to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings.
- Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period. If a distributor is proposing to allocate a deferral or variance account for which the OEB has not established an approved allocator, the distributor must propose an allocator based on the cost driver(s)..
- Propose a charge type (fixed or variable) for recovery purposes, in accordance with section 2.8.2 (Rate Design Policy), and include this in the continuity schedule.
- Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period, an explanation must be provided.
- Establish separate rate riders to recover the balances in the RSVAs from Market Participants ("MPs") who must not be allocated the RSVA account balances related to charges for which the MPs settle directly with the IESO (e.g. wholesale energy, wholesale market services).

- In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:
  - o Causation – The forecasted expense must be clearly outside of the base upon which rates were derived;
  - o Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements; and
  - o Prudence – The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, applicants must include a draft accounting order which must include a description of the mechanics of the account, including providing examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

2.9.7.1 Global Adjustment

Most customers pay the global adjustment (GA) charge based on the amount of electricity they consume in a month (kWh). These customers are referred to as Class B. Customers who participate in the Industrial Conservation Initiative (ICI), referred to as Class A, pay global adjustment based on their percentage contribution to the top five peak Ontario demand hours (i.e. peak demand factor) over a year-long period. Given that distributors typically settle GA costs with Class A customers on the basis of actual (i.e. non-estimated) costs, no global adjustment variance balance shall be allocated to these customers.

For Class B customers, the global adjustment variance account (Account 1589) captures the difference between the amounts billed (or estimated to be billed) to non-RPP customers by the distributor and the actual amount paid by the distributor to the IESO (or host distributor) for those customers.

When clearing balances from the GA variance account, distributors must establish a separate rate rider included in the delivery component of the bill that would apply prospectively to non-RPP customers.

As a new addition for 2016 applications, a distributor must now provide a description of its settlement process with the IESO or host distributor. It must specify the GA rate it uses when billing its customers (1^{st} estimate, 2^{nd} estimate or actual) for each rate class, itemize its process for providing consumption estimates to the IESO, and describe the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. The description should detail the distributor's method for estimating RPP and non-RPP consumption, as well as its treatment of embedded generation or any embedded distribution customers. Distributors are reminded that they are expected to use accrual accounting.

As of July 1, 2015, per O.Reg 429/04, an eligible customer with a maximum hourly demand over three megawatts, but less than five megawatts, can elect to become a Class A for an applicable adjustment period of one year.

Any distributor who serves any eligible Class A customers is asked to identify the number of Class A customers it served in 2014 and is serving as of July 1, 2015, if different. If more than two class A customers are served, the distributor must report the combined peak demand factor of its Class A customers for each period.

A distributor with one of these newly Class A-eligible customers should also propose an appropriate allocation for the recovery of the global adjustment variance balance based on their settlement process with the IESO or host distributor for any residual GA variance balances that might have accrued prior to those customers being classified as Class A customers. This information will be used to inform future disposition of GA variance account balances.