Ontario Energy Board Commission de l’énergie de l’Ontario

Ontario

Ontario Energy Board

Filing Requirements For
Electricity Distribution Rate Applications
- 2018 Edition for 2019 Rate Applications -

Chapter 2

Cost of Service

July 12, 2018

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

2.0 General Requirements

The purpose of this document is to set out the filing requirements for cost of service rate applications by electricity distributors. The filing requirements have been established to require complete and transparent information sufficient to inform the Ontario Energy Board (OEB) and interested parties of all material facts related to the distribution of electricity by an electricity distributor in order to set rates.

2.0.1 Relevant Chapters

Chapter 2 relates to a cost of service rate application. In addition to the *Handbook for Utility Rate Applications* (the Rate Handbook), which outlines the key principles and expectations of the OEB when reviewing an application, the filing requirements contained in this chapter and Chapter 5 outline all of the relevant information that is necessary for a complete cost of service application. The OEB currently uses three incentive rate-setting (IR) methods: (1) 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.

While there are no filing requirements for Custom IR applications, utilities should be guided by these filing requirements when preparing Custom IR applications. If filing a Custom IR application which is underpinned by (a) cost of service test year(s), the utility must file all necessary documentation for a CoS application, including the Chapter 2 appendices and the models discussed in section 2.0.2.

Filing requirements for IRM rate applications (i.e. the Price Cap IR and Annual IR Index options) are provided in Chapter 3. Applicants should also 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.

The OEB posts an updated checklist on its electricity distribution rates web page annually based on these filing requirements. Distributors may find the checklist a useful aid in preparing their applications. Any deviations from the filing requirements need to be identified and explained.

[1] The OEB considers cost of service (CoS) and rebasing to be the same and therefore these terms are used interchangeably for the purposes of this chapter.

2.0.2 Appendices and Models

The various appendices and models 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-K – Employee Costs provides tables related to section 2.4.3.1 – Workforce Planning and Employee Compensation). These appendices and models are available in Microsoft Excel format on the OEB's website and must be completed by applicants and filed as part of a CoS application in PDF format, as well as in live Microsoft Excel format. Applicants must also provide PDF and Excel copies of the current tariff sheet. At the draft rate order stage, applicants are required to provide an updated Revenue Requirement Work Form (RRWF). Applicants are also required to update certain tabs in the Chapter 2 Appendices, if changes are necessary. The required tabs are indicated in the Appendices themselves at the "Index" tab and applicants must file the workbook in its entirety at the draft rate order stage.

The models issued by the OEB 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 applicant is responsible for the completeness and accuracy of its application. This includes the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses to support its application. The applicant is also 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.

2.0.3 Separation of Distribution Function

Distributors are rate-regulated by the OEB on a stand-alone basis, which means that the application must show the regulated entity separately from its parent company or any other affiliates, both regulated and 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.

2.0.4 Cost of Service Application in Advance of Scheduled Application

Distributors 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.

2.0.5 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 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.

2.0.6 Late Filing of Cost of Service Application

The OEB establishes deadlines for the filing of cost of service applications each year. Generally, distributors filing applications for January 1 rates are expected to file such applications by the end of April of the prior year. The effective date of rates approved for applications filed after the required date may be later than the effective date proposed.

Late applications filed after the commencement of the rate year for which the application is intended will not be accepted by the OEB. For example, for an application to set rates on a cost of service basis commencing May 1, 2019, an application filed after April 30, 2019 (the last business day before the commencement of the rate year) should be converted to a 2020 rate application. This means that the 2019 test year now becomes the bridge year and the applicant should provide a 2020 budget to underpin the updated test year. In this instance, the OEB expects that a distributor will not seek any further rate adjustment for the 2019 rate year but will remain with the rates set for 2018. Applicants for 2020 rates may seek, in this instance, to align their fiscal and rate years.

2.0.7 Structure of Application

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 (includes the Distribution System Plan)
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 at Tab 3. 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.

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

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, as described in section 2.2.1.1.
- 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 year (calendar year during which new rate year commences)
    - 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
- Tariff Schedule and Bill Impacts Model
- Chapter 2 Appendices
- Electricity Distributor Deferral and Variance Account Review (EDDVAR) Continuity Schedule
- Income Tax/Payments In Lieu of Federal and Provincial Corporate Tax (PILs) Work Form
- Cost Allocation Model
- Retail Transmission Service Rates (RTSR) Model
- Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Model
- Advanced/Incremental Capital Module (ACM/ICM) Model (if applicable)

When filing Excel models, applicants should ensure that any links within these models are not broken (e.g. links to other documents that are not filed with the application) and the filed versions of such models should be named so that they can be easily identified.

2.0.8 Materiality Thresholds

The applicant must provide justification for annual changes to its rate base, capital expenditures, and operations, maintenance and administration (OM&A) costs. To ensure the OEB's review is focused on matters that are material, generally the OEB requires explanations for variances exceeding certain amounts.

The thresholds differ for each applicant, depending on the magnitude of the revenue requirement. A written explanation is required for rate base, capital expenditures, and OM&A costs if the revenue requirement impact of variances exceeds the applicable utility-specific threshold 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.

2.0.9 Accounting Matters

The OEB notes that utilities must have converted to International Financial Reporting Standards (IFRS) as of January 1, 2015, unless they adopted United States Generally Accepted Accounting Principles (USGAAP) or Accounting Standards for Private Enterprises (ASPE). It is the OEB's expectation that most distributors will have rebased under IFRS or other accounting standards. Applicants that have not rebased under IFRS should consult previous filing requirements for guidance or contact OEB staff.

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 nine sections:

1) Table of Contents
2) Executive Summary and Business Plan
3) Customer Summary
3) Administration
4) Distribution System Overview
5) Application Summary
6) Customer Engagement
7) Performance Measurement
8) Financial Information
9) Distributor Consolidation

2.1.1 Table of Contents

The application must contain a Table of Contents listing the major sections and subsections of the application. The electronic version of the application must be appropriately bookmarked to provide direct access to each section and subsection of the Table of Contents.

2.1.2 Executive Summary and Business Plan

The applicant must provide an Executive Summary to identify key elements of its proposals and the Business Plan underpinning its application, as guided by the Rate Handbook, including plain language information about the applicant's goals.

2.1.3 Customer Summary

The applicant must also provide a brief but complete summary of its application that will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to customers of the applicant. This summary must include the main requests or proposals in the application with appropriate section references to the application content, as well as the rationale behind each request. The summary must include a description of the impacts of the requests, including bill impacts for a consumer using 750kWh, as well as a typical consumer for a distributor's service area for each of the residential and small business customer classes. The summary must be written in plain language in a way that is easily comprehensible to residential and small business customers.

2.1.4 Administration

This section must include the following:

- The contact information for the primary contact for the application, who 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 to communication with 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 the 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 which 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(s) regarding publication media.
- A list of one or more accessible community-based venues for each non-contiguous area that the utility serves. This would serve as the list of potential venues for a community meeting to be held to allow the applicant's customers to learn more about the application; to find out how the OEB will review the application; and to learn about how to get involved in, and provide comments on, the application. Where possible, the list of potential venues should include local community buildings such as community centres, legion halls, schools, libraries or similar facilities that are accessible to persons with disabilities, have free parking, and are on or near local transit routes, if applicable. The distributor is also asked to provide three or more possible dates for meetings that fall on a Tuesday, Wednesday or Thursday; do not conflict with any major community events; and on which the appropriate company executives and other necessary distributor employees would be available to attend and participate in the community meeting(s).
- Bill impacts (the bill impacts that result only from distribution cost changes per sub-total A of Tariff Schedule and Bill Impacts spreadsheet model) to be used for the notice of application for a typical residential customer using 750 kWh per month and for a General Service < 50kW customer using 2000 kWh per month. A distributor should also include and propose bill impacts based on alternative consumption profiles and customer groups as appropriate given the consumption patterns of its customers.
- Statement as to the form of hearing requested (i.e. written or oral) and an explanation for the applicant's preference
- The requested effective date
- A statement identifying and describing any changes to methodologies as used in previous applications

- Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application
- 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 also be provided. If the Conditions of Service would change as a result of approval of the application, the distributor must also identify all such changes.
- Confirmation that there are no rates or charges listed in the Conditions of Service that are not on the distributor's Tariff of Rates and Charges
- 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's Board of Directors 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.
- A list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts), new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified in Appendix 2-A and clearly documented in the appropriate sections of the application. A PDF copy of this Appendix should be provided in this section.

2.1.5 Distribution System 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 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 status (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) must be clearly identified, including the percentage of load that is supplied through the host distributor(s). If the distributor is a host distributor, the applicant should identify whether there is a separate

Embedded Distributor customer class or if any embedded distributors are included in other customer classes (such as GS > 50 kW).

- 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 that the distributor is asking the OEB to deem as distribution assets in the present application

2.1.6 Application Summary

At a minimum, the items listed below must be provided. Applicants must also separately identify 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.

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 each year and brief explanation of impacts resulting from any change in accounting standards

C. Load Forecast Summary

- Load and customer growth (% change kWh, kW and change in customer numbers[2] from last OEB-approved)
- Brief description of forecasting method(s) used for customer/connection and consumption/demand

D. Rate Base and DSP

- Summary of the major drivers of the DSP
- 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

[2] Please ensure when reporting customer numbers to indicate whether they are year-end or average.

- 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 summary table showing the proposed capital structure and cost of capital parameters resulting in the Weighted Average Cost of Capital (WACC)
- 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(s)
- Any new Deferral and Variance Accounts (DVAs) requested and any requested discontinuation of existing DVAs

I. Bill Impacts

- Summary of total bill impacts ($ and %) for typical customers in all customer classes

2.1.7 Customer Engagement and Community Meetings

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 that customers would face). The application should discuss any feedback provided by customers and how this feedback shaped the final proposals included in the application.

The impact of customer engagement activities on the development of the capital plan are to be filed as part of the capital plan requirements in Chapter 5.

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. Distributors should provide a summary of feedback received from customers through these engagement activities.

Distributors must complete Appendix 2-AC – Customer Engagement Worksheet. 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 in that exhibit.

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

The OEB will hold one or more community meetings for all cost of service or custom IR rate cases after the application has been filed. A distributor is required to participate in the OEB-hosted community meetings by providing relevant customer and local knowledge for meeting planning purposes, preparing a presentation and other materials as may be required, attending the meeting and having one or more executives of the distributor available to present the distributor's rate application information, and answer customer questions.

To ensure that the community meeting(s) does not significantly alter hearing timelines, the OEB expects a distributor to advise the OEB in writing no later than 30 days prior to filing its application of its intention to file with the OEB. This advanced notice will allow the OEB to contact the distributor and begin planning the meeting(s).

A distributor will be required to advertise the OEB's community meeting(s) on a bill insert developed by the OEB in the next available billing cycle following the filing of the application or sooner, as appropriate. The OEB may require the distributor to advertise the meeting(s) through other channels as well.

2.1.8 Performance Measurement

Under the Renewed Regulatory Framework (RRF), a distributor is expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services, e.g. efficiencies realized as a result of the implementation of smart meters and related technologies. To facilitate performance monitoring and benchmarking of distributors the OEB uses a scorecard approach.

The *Report of the Board on Performance Measures for Electricity Distributors: A Scorecard Approach* 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 which form the basis of the RRF Report.

Along with the scorecard, the OEB publishes a report each year on the benchmarking of electricity distributor cost performance. As described in the OEB's *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors,* an econometric model is used to generate efficiency rankings of each distributor to one of five groups based on their annually benchmarked cost performance.

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. The distributor must discuss its plan(s) for continuous improvement currently and going forward.

Applicants must identify performance improvement targets, 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 applicant must provide a forecast of its efficiency assessment using the PEG forecasting model for the test year for the purposes of providing the OEB with a directional indication of efficiency. The application should discuss how the results obtained from the PEG forecasting model have informed the applicant's business plan and the application.

2.1.9 Financial Information

This section must include the following:

- Non-consolidated audited financial statements of the utility (excluding operations of affiliated companies that are not rate-regulated) 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 in order to, as one example, separate non-distribution 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 distributor and of the parent company, as available and applicable
- Rating agency report(s), if available
- Prospectuses, information circulars, etc. for recent and planned public debt or equity offerings
- Any change in tax status (e.g. from a corporation to a limited partnership)
- A description of existing accounting orders and list of any departures from these orders
- Any departures from the Uniform System of Accounts (USoA)
- The accounting standard(s) used for general purpose financial statements and when they were adopted

If an applicant is conducting non-distribution 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: Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities G-2009-0300*, September 15, 2009, or any successor document.

2.1.10 Distributor Consolidation

A distributor that has acquired or amalgamated with (an) other distributor(s) may elect to defer rebasing for a period up to 10 years after the closing of the transaction.

If a distributor has acquired or amalgamated with any other distributor(s) since its last rebasing application, it should refer to the *Handbook to Electricity Distributor and Transmitter Consolidations*, issued on January 19, 2016 for information regarding the OEB's policy on rebasing after consolidation.

A distributor that is filing an application to rebase following a consolidation must:

- Identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs (e.g. programs, projects and/or assets) that are being proposed to remain in or enter rate base and/or revenue requirement
- Specify whether any commitments made to shareholders are to be funded through rates
- List the exhibits of its application in which any such incentives are discussed
- Detail the actual savings as a result of consolidation compared to what was in the approved consolidation application and explain how these savings are sustainable
- Detail the efficacy of any rate plan confirmed as part of a Mergers, Amalgamations, Acquisitions and Divestitures (MAADs) application
- Identify approved ACMs or ICMs from a previous Price Cap IR application it proposes be incorporated into rate base.

Distributors should note that the requirement to file a distribution system plan every five years still applies even if a consolidation application has been filed or approved.

2.2 Exhibit 2: Rate Base

This exhibit includes information on rate base, capital expenditures and service quality.

2.2.1 Rate Base

This exhibit must include the following sections:

1) Overview
2) Gross Assets – Property, Plant and Equipment (PP&E) and Accumulated Depreciation
3) Allowance for Working Capital

2.2.1.1 Overview

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

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 or quarterly values, it must document the methodology used. Rate base may 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. 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, 2018 and December 31, 2019 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 (CWIP) and Asset Retirement Obligations (AROs).

A distributor may include in-service balances previously recorded in deferral or variance accounts, such as MIST[3] 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.

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 ACM or IRM adjustment(s), including what was approved and what was spent, if the distributor received approval for an ACM or ICM adjustment as part of a previous IRM application

[3] "MIST meter" means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to "Metering Inside the Settlement Timeframe"

Continuity statements must be reconcilable to the calculated depreciation expenses, reported under Exhibit 4: Operating Costs, and presented by asset account. Further guidance is included in the filing requirements appendices spreadsheets and under section 2.4.4 below.

The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historical, bridge and test years, and that any amounts related to gains or losses on disposals have been included in Account 1575, IFRS-CGAAP Transitional PP&E amounts.

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 take one of two approaches for the calculation of its allowance for working capital: (1) use the default allowance of 7.5% of the sum of Cost of Power (CoP) and OM&A or (2) file a lead/lag study.

If the applicant has been directed by the OEB to undertake a lead/lag study as part of its last rate application, it must comply with that order.

The lead/lag study will include a lead/lag 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) 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.

The commodity price estimate used to calculate the CoP must be determined by the split between RPP and non-RPP Class A and Class B customers based on actual data and using the most current RPP (TOU) prices established for the May 1, 2018 to April 30, 2019 period. The calculation must fully consider all other impacts resulting from the *Ontario Fair Hydro Plan Act, 2017* (Fair Hydro Plan) as described in the OEB report *Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 to April 30, 2019.* Distributors must complete Appendix 2-Z – Commodity Expense.

In consideration of the impact of the Fair Hydro Plan, Non-RPP actual data must be split between Class A and Class B customers (RPP and non-RPP). Non-RPP Class B consumption data must be further split between customers eligible for the Global Adjustment (GA) modifier vs. non-eligible. The GA modifier must be applied to eligible customers and a weighted average commodity price must be determined by the split between RPP, eligible non-RPP and non-eligible Non-RPP customers. For customer classes that include Class A customers, a distributor must incorporate Class A GA cost by completing the relevant section in Appendix 2-Z.

If a distributor expects test year consumption data to vary significantly, a distributor may provide a forecast of the expected split between Class A and Class B and the expected split between RPP, non-RPP eligible for modifier and non-RPP non-eligible for modifier consumption data and provide a brief explanation of the forecast.

The calculation must use the most recent approved Uniform Transmission Rates (UTRs), Smart Metering Entity charge and regulatory charges.

2.2.2 Capital Expenditures

Included within this exhibit are the following sections, which will include the DSP as outlined in Chapter 5:

1) Distribution System Plan
2) Capital Expenditure Summary and Variance Analysis
3) New Policy Options for Funding Capital
4) Addition of ACM/ICM Assets to Rate Base
5) Capitalization Policy
6) Capitalization of Overhead
7) Costs of Eligible Investments for Distributors
8) Service Quality

2.2.2.1 Distribution System Plan

Distributors must file a consolidated DSP in accordance with Chapter 5. 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 element within Exhibit 2. Most distributors in recent years have found it convenient to file the DSP as an appendix to Exhibit 2; this has proven to be workable for review of the DSP as part of the rate application.

2.2.2.2 Capital Expenditures Summary and Variance Analysis

In addition to the DSP, the applicant must provide an overall summary of capital expenditures over the past five historical years, including the last OEB-approved amounts, as well as the bridge year and the test year. The summary must show capital expenditures, treatment of contributed capital, and additions and deductions from Construction Work in Progress. As part of Exhibit 2, a distributor must also provide explanations of year-over-year variances and an explanation of the variance, if any, between the OEB-approved capital expenditure amount in the last rebasing year as compared to the actual expenditures for that year.

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.

2.2.2.3 Policy Options for the Funding of Capital

On September 18, 2014, the OEB issued the *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*[4] (the ACM Report). The ACM reflects an evolution of the 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 come into service during the subsequent Price Cap IR term. These will be discrete projects as documented in the DSP. The distributor must establish the need for and prudence of these projects based on DSP information. The distributor must also identify that it is proposing ACM treatment for these future projects, and provide the preliminary cost information and ACM/ICM 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 the completed spreadsheet: Capital Module Applicable to ACM and ICM.

The timing and actual amount of the rate riders used to recover the costs of 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 the project comes into service. At

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[4] EB-2014-0219

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. The distributor must also provide explanations for material variances between actual and forecasted costs (and timing, if applicable). However, the nature and need for the project will be determined as part of the ACM in the cost of service application so it is considered as part of the overall DSP for the utility.

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.

On January 22, 2016, the OEB issued the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report*. This report made changes to the materiality threshold on which ICM and ACM proposals are assessed, but otherwise does not alter the requirements for ACM and ICM proposals by an applicant. The Supplemental Report also reaffirms the applicability of the half-year rule for determining the return on capital in the first year that assets enter service.

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

Any distributor that has an approved ACM or ICM from a previous Price Cap IR application must file a schedule of the ACM/ICM capital asset amounts (i.e. PP&E and associated depreciation) it proposes to 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 for variances between forecast and actual capital spending during the IRM plan term.

A distributor 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 charges are calculated using simple interest applied to the monthly opening balances and recorded in the following sub-accounts:

- 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 OEB for deferral and variance accounts for the respective quarterly period as published on the OEB's website.[5]

If the OEB determines that a true-up of variances is required, the recalculated revenue requirement relating to the OEB-approved ACM/ICM capital expenditures should be compared to the rate rider revenues collected in the same period and the variance will be refunded to or collected from customers through a rate rider.

2.2.2.5 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 accounting changes must be implemented consistent with the OEB's regulatory accounting policies as set out for MIFRS as contained in the *Report of the Board on Transition to International Financial Reporting Standards*, [6] the Kinectrics Report, and the Accounting Procedures Handbook (APH).

Since most of the scheduled cost of service filers for 2019 last rebased in 2014, most applicants will already have reflected in their rates updates to depreciation expense and capitalization policies in a previous rebasing application. 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, the applicant must identify any change(s) and the reason(s) for the change(s).

2.2.2.6 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 the change.

[5] 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.
[6] EB-2008-0408

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

For any costs incurred to make investments that are eligible for rate protection as described in section 79.1 of the *Ontario Energy Board Act, 1998* (OEB Act) and O.Reg. 330/09 under the OEB Act, including any facilities forecast to enter service beyond the test year, the distributor may seek approval to recover the rate protection component of the costs. The applicant must provide a proposal 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*[7] (the Direct Benefits Report). If eligible investments are approved by the OEB, a variance account is used to record the actual costs of the investments, and revenue received from the Independent Electicity System Operator (IESO) pursuant to the provincial pooling mechanism set out in section 79.1 of the OEB Act. Applicants should refer to the OEB's March 2015 APH Guidance for further information.

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 of its project(s). The component of such investments not eligible for rate protection will be treated the same as any other new capital investment undertaken by a distributor, and will not be separately tracked.

On March 22, 2017, the Ontario government enacted the *Burden Reduction Act*, 2017, which amended the OEB Act, subsection 79.1 (1) by striking out "shall provide" and substituting "may provide" in relation to the OEB approving rate protection for eligible investments for the purpose of connecting or enabling the connection of a qualifying generation facility. In conjunction with this change, the request for rate protection will be subject to the materiality threshold in section 2.0.8.

Appendices 2-FA through 2-FC must be filed, identifying all material eligible investments (to a maximum of five years) for which rate protection is required. These appendices form the mechanism to calculate the applied-for 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.

For distributors that are already receiving rate protection as a result of a previous application and approval (in many cases, based on a forecast of capital expenditures on

[7] EB-2009-0349

qualifying connection assets), the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold in section 2.0.8.

2.2.2.8 Service Quality

Chapter 7 of the OEB's Distribution System Code outlines the OEB's expectations regarding Service Quality Requirements (SQR) for Electricity Distributors. An applicant is required to provide the reported SQRs for the last five historical years. A distributor must also provide an explanation for any under-performance, if applicable, and provide actions taken or to be taken to address the issue. If available, any outcomes of such action must be provided.

A completed Appendix 2-G, documenting both the Service Quality and Service Reliability indicators, must be filed. An applicant must confirm that data are consistent with the scorecard or must explain any inconsistencies.

2.3 Exhibit 3: Operating Revenue

This exhibit includes evidence on the applicant's forecast of customers,[8] energy and load, service revenue and other revenue, and variance analyses related to these items.

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 and other variables used in forecasting volumes).

The applicant must also provide an explanation of the weather normalization methodology used. Generic load profiles and universal normalization methods may not reflect the unique customer mix, weather and economic activities of a utility's service territory.

The applicant must include in the test year forecast any impacts arising from the persistence of Conservaton 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 LRAMVA.

[8] Customer numbers must be identified as representing either year-end numbers or the annual average.

A distributor must complete Appendix 2-IB – Actual and Forecast Load and Customer Data. The customer/connection and load forecast for the test year must also be entered on a new tab of the Revenue Requirement Work Form, Sheet 10: Load Forecast.

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.

2.3.1.1 Multivariate Regression Model

The following must be provided:

- Rationale to support the model chosen. A discussion of modelling approaches considered and alternative models tested must be provided.
- 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)
- 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. If the applicant proposes an alternative approach, it must be supported.
        - Definitions of HDD and CDD, including:
            - Climatological measurement point(s) (i.e. identification of Environment Canada weather station(s)) and why these are appropriate for the distributor’s service territory
            - Identification of base degrees 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 10-year average <u>and</u> 20-year trends in HDD and CDD
    - Rationale to support the weather-normalization methodology 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. if billing data are not based on calendar monthly readings as obtained from

interval or smart meters) must be provided, including an explanation of why the constructed demand series is suitable for modelling.

- Any binary variables used to either account for individual data points or to account for seasonal or cyclical trends or for discontinuities in the historical data. Where such a variable has been used, a complete explanation and justification of the variable must be provided. The use of binary variables should be limited, and overlap with other variables should be avoided (e.g. including seasonal binary variables along with HDD and CDD).
- 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.

2.3.1.2 Normalized Average Use per Customer Model

The following must be provided:

- Rationale to support the NAC methodology 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 or forecasts 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 *Guidelines for Electricity Distributor Conservation and Demand Management*[9], it is expected that the distributor will integrate an adjustment into the 2019 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 (i.e. 2019) CDM programs on the 2019 load forecast.

The CDM targets and the LRAMVA balances are based on the reported IESO[10] 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

[9] EB-2012-0003

[10] Formerly the Ontario Power Authority

annualized amount. For this reason, the amount that will be used for the LRAMVA will be related to, but not equal to, the CDM adjustment for the load forecast.

The distributor should document the CDM savings to be used as the basis for the 2019 LRAMVA balance and the corresponding adjustment to the 2019 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 to a customer class, 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.

The distributor should include a proposal, with the appropriate rationale, for the level of CDM reductions reflected in the 2019 load forecast.

Appendix 2-I has been modified to also take into account projected savings in 2019 for 2018 and 2019 CDM programs that the distributor will undertake as part of the 2015-2020 CDM plan. The distributor also has the option to alter the default methodology for the 2015 to 2017 CDM kWh savings to align with its 2015-2020 CDM plan, but must clearly explain and support its proposed approach.

2.3.2 Accuracy of Load Forecast and Variance Analyses

Appendix 2-IB must be completed and the applicant must provide the following analyses:

- For customer / connection counts:
  - Identification as to whether customer/connection count is shown in year-end or year average format
  - Year-over-year variances in changes of customer/connection counts, with explanations for changes in the definition of, or major changes in the composition of, each customer class. Major changes would include material loss, gain or re-classification of customers in one or more customer classes
  - Explanations of the bridge year and test year forecasts by rate class
  - For the last cost of service rebasing, variance analysis between the last OEB-approved and the actual results. Explanations for material differences should be provided
- For consumption and demand:
  - Explanation, and details as necessary, to support how kWh are converted to kW for applicable demand-billed customer classes
  - Year-over-year variances in consumption (kWh) and demand (kW or Kilo Volts Amps (kVA)) (the latter for demand-billed classes) by rate class and for system consumption (kWh) overall, with explanations for material changes in the definition of, or major changes over time. This comparison should be done for both:

        - Comparison of historical actuals against each other
    - Comparison of historical weather-normalized actuals over time. Explanations of the bridge year and test year forecasts by rate class should be provided. Such analysis and explanation should document how these vary from or are trending from both historical actuals and from weather-normalized actuals
    - For the last cost of service rebasing, variance analysis between the last OEB-approved and the actual and weather-normalized actual results. Explanations for material differences should be provided.
- For revenues:
    - Calculation of bridge year forecast of revenues at existing rates
    - Calculation of test year forecasted revenues at each of:
        - Existing rates
        - Proposed rates[11]
    - Year-over-year variances in revenues comparing historical actuals and bridge and test year forecasts.

The following data and analyses should be provided with respect to average consumption for each rate class:

- Weather-actual and weather-normalized average annual consumption or demand per customer, as applicable for the rate class, for:
    - Last OEB-approved
    - Historical years
- Weather-normalized average annual consumption or demand per customer, as applicable for the rate class, for the bridge and test years
- An explanation of the net change in average consumption from last OEB-approved and actuals for historical, bridge and test years, based on year-over-year variances and any apparent trends in the data

Appendix 2-IA provides further instructions for filling out Appendix 2-IB.

All data used to determine the customers/connections, demand and load forecasts must be presented and filed in a live Microsoft Excel spreadsheet format.

2.3.3 Other Revenue

The following information on each of the other distribution revenue accounts must be provided and Appendix 2-H completed:

[11] Test year revenues at existing rates and at proposed rates are carried forward and used in Exhibit 6 (Revenue Requirement and Revenue Sufficiency/Deficiency), Exhibit 8 (Rate Design) and in the RRWF.

- 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 (including any credits to be provided to customers, e.g. for paperless billing)
- 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 (see Appendix 2-N for the required format)
- Accounts related to affiliate revenue and affiliate expense are shown in the footnote of Appendix 2-H.
- Revenue from affiliate transactions should be recorded in Account 4375, Revenues from Non Rate-Regulated Utility Operations.
- Expenses from affiliate transactions should be recorded in Account 4380, Expenses of Non Rate-Regulated Utility Operations.

A distributor shall refer to Article 220 - Uniform System of Accounts and Article 340 - Allocation of Costs and Transfer Pricing of the APH for more detailed accounting guidance.

Appendix 2-H – Other Operating Revenue, indicates that each account must be broken down in more detail, showing the components of each account.

The balances recorded in Account 4375, Revenues from Non Rate-Regulated Utility Operations, and Account 4380, Expenses of Non Rate-Regulated Utility Operations, must reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Cost Allocation for the three historic years, the bridge year and the test year. Any differences must be reconciled.

Any revenue related to microFIT charges must be recorded as a revenue off-set in Account 4235 – Miscellaneous Service Revenue and not be included as part of the base distribution revenue requirement.

As outlined in section 2.4.3.2 – Shared Services and Corporate Cost Allocation, costs that are included in an applicant’s OM&A must be excluded from the account balances incorporated into Appendix 2-H – Other Operating Revenue (i.e. excluded as offsets to the revenue requirement) and vice versa. Costs that are included in an applicant’s OM&A must also be excluded from Appendix 2-N – Shared Services and Corporate Cost Allocation.

The applicant must ensure that its transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business, products or services. If cross-subsidization occurs, the applicant must describe this issue in more detail and provide an explanation as to why the applicant has not rectified this issue.

The applicant must ensure compliance with Article 340 of the APH and provide explanations for any deviations if applicable.

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

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

2.4 Exhibit 4: Operating Expenses

Exhibit 4 includes information that summarizes the OM&A expenses, depreciation expense and taxes, collectively referred to as Operating Expenses. This exhibit must include the following sections:

- Overview
- Summary and Cost Driver Tables
- Program Delivery Costs with Variance Analyses
- Depreciation/Amortization/Depletion
- Taxes or Payments In Lieu of Taxes (PILs)
- Conservation and Demand Management

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, including OM&A per customer (and its components) for the historical, bridge and test years, as discussed above
- 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 filing cost of service applications should be mindful of this rate, and, if proposing to use a different inflation rate in support of their proposed OM&A, should provide a full explanation supporting their proposal.

- Business environment changes

2.4.2 OM&A 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 Full Time Equivalent (FTE)(Appendix 2-L).

Appendix 2-JC must be filed to provide OM&A details and variance analysis on a program basis. This table must reflect the entire OM&A envelope requested for recovery, and applicants must provide information for the bridge and test years. Appendix 2-JB should be used to provide 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.). Appendix 2-L includes a breakout of OM&A per customer into Operations and Maintenance per customer and Administration expenses per customer.

The applicant must identify the overall level of increase (decrease) in OM&A expense in the test year in relation to any decrease (increase) in capitalized overhead.

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, consistent with Appendix 2-D.

2.4.3 OM&A Program Delivery Costs with Variance Analysis

As identified previously, applicants must complete the revised Appendix 2-JC – OM&A Programs Table to identify OM&A costs by program. This will include a variance analysis between the test year costs against each of the last OEB-approved costs and the most recent actuals for variances that are outliers based on the historical trend. The variance analysis 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:

- Workforce Planning and 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 Workforce Planning and Employee Compensation

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 expects that distributors will provide a description of their previous and proposed workforce plans, including compensation strategy. Distributors must discuss the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTE numbers and compensation. A complete explanation for all years includes:

- Year-over-year variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees
- 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 that are virtual utilities (i.e. utilities that have outsourced all or the majority of functions, including employees, to affiliates) must also complete this appendix in relation to the employees of the affiliates 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, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A.

A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for the last OEB-approved rebasing application, and for 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.

The OEB initiated a consultation[12] on the regulatory treatment of pension and OPEB costs in May 2015. On September 14, 2017, the OEB issued its report on *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs*. An applicant is to be guided by this report in determining its pension and OPEB costs that it is requesting be recovered through rates in its application. The applicant must clearly indicate if pension and OPEB costs are proposed to be recovered using the default accrual basis or the cash basis. If an applicant is proposing to include pension and OPEB expenses based on the cash method, applicants must provide sufficient supporting rationale and evidence for adopting the cash method. If an applicant is proposing to change the basis in which pension and OPEB costs are included in OM&A from its last rebasing application (e.g. from cash to accrual) it must quantify the impact of the transition. For all circumstances the applicant must file the evidence required by the OEB to support the quantum.

2.4.3.2 Shared Services and Corporate Cost Allocation

Shared Services are 'shared corporate services' as defined in the Affiliate Relationships Code (ARC). The applicant must identify all shared services among the affiliated entities, including the extent to which an applicant is a "virtual" utility and justify its proposed shared services and corporate cost allocation in detail.

For shared services among affiliated entities, an applicant must provide at a minimum:

- The type of service provided or received
- The pricing methodology (e.g. cost-base, market-base, tendering, etc.)

Corporate Cost Allocation is an allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa). The applicant must provide at a minimum:

- A list of shared services
- The allocation methodology
- A list of costs and allocators and an explanation of how the distributor derived the allocator
- Any third party review of the corporate cost allocation methodology used

[12] EB-2015-0040

Applicants should ensure and be able to demonstrate 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 and for 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 Directors-related costs for affiliates that are included in the utility's own costs.

Please see section 2.3.3 – Other Revenue above for an overview of items that the applicant must address related to its affiliate transactions and the associated required regulatory accounting practices, distribution rate treatments, and adherence to the ARC.

2.4.3.3 Purchases of Non-Affiliate Services

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 material transactions that are not in compliance with the applicant's procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, the applicant must provide an explanation as to why this was the case, as well as the following information for these transactions:

- Summary of the nature and cost 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 IRM 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 the 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 incremental level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify 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), for the reasons provided in section 2.4.3.4 above. 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)

As set out in the *Report of the Board on Low Income Energy Assistance Program* (the LEAP Report), the OEB 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. A distributor must include the relevant LEAP amount as part of its OM&A expenses in its initial application, which should be updated at the draft rate order stage. For greater clarity, OEB-approved total distribution revenue means a distributor's forecasted service revenue requirement as approved by the OEB.

Applicants may propose a LEAP fund higher than 0.12% if its demographics might lead to greater need. Details of those demographics should be provided.

The LEAP amount is to be recovered from all rate classes based on the respective distribution revenue of each of those rate classes.

2.4.3.7 Charitable and Political Donations

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). Applicants must provide detailed information for all contributions that are claimed for recovery.

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[13] 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 and support 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. The applicant must file the applicable depreciation appendix as provided in the Chapter 2 Appendix 2-C.These must tie back to the accumulated depreciation balances in the fixed asset continuity schedule (Appendix 2-BA) under rate base.
- 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). In the *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report* the OEB determined that the half-year rule approach would continue to be used. Distributors can propose a different 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

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

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. Most distributors filing for 2019 rates have rebased with these accounting changes for depreciation expense reflected in a prior application.

An applicant that has not made any changes to its depreciation expense policy or asset service lives must state that this is the case. For an applicant that has made any depreciation expense policy or asset service lives changes since its last rebasing application, the following is required:

- Identification of the changes and a detailed explanation for the causes of the changes, including any changes subsequent to those made by January 1, 2013
- The applicant must use the OEB-sponsored Kinectrics Report 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. 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 if there have been changes in asset service lives since the applicant's last rebasing application or if this is the first rebasing application that an applicant is reflecting the OEB's mandatory depreciation expense policy changes.

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

Applicants must make use of the stand-alone principle when determining these amounts.[14] 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.

2.4.5.1 Income Taxes or PILs

The applicant must provide the following information:

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

- Detailed calculations of income tax or PILs, as applicable. These calculations must include a completed PDF and live Microsoft Excel version of the Income Tax /PILs model available on the OEB's website, including derivation of adjustments (e.g. tax credits, CCA adjustments) for the historical, bridge and test years. Regulatory assets and liabilities must be excluded from taxes/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 the most recent Federal and Provincial tax returns. Non-utility tax items, if material, must be separated. This is to be done in the PILs model.
- Financial statements included with tax returns, if different from the financial statements filed in support of the application (see section 2.1.9)
- A calculation of tax credits (e.g. Apprenticeship Training Tax Credits, education tax credits). A Scientific Research and Experimental Development 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 must be either removed or redacted from the filing, and the unredacted version need not be filed.
- Supporting schedules, calculations and explanations for "other additions" and "other deductions" in the applicant's PILs model
- Completion of the integrity checks in the PILs model

2.4.5.2 Other Taxes

Taxes other than income taxes or PILs, as defined in the APH (e.g. property taxes), should only be included in Account 6105, effective January 1, 2012. Account 6105 is not an OM&A account and should therefore be excluded from all OM&A totals. The applicant should provide an explanation of how these tax amounts are derived.

2.4.5.3 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 2019 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.

2.4.6 Conservation and Demand Management

CDM activity is predominately funded through programs contracted with the IESO and funded through the GA
mechanism, and therefore costs directly attributable to these CDM programs (e.g. staff labour dedicated to such programs) must not be included in the revenue requirement to be recovered through distribution rates. An application must provide a statement confirming that no such costs are included in the revenue requirement. Conservation programs funded per section 5.4.1.1 of Chapter 5 are included in the revenue requirement.

2.4.6.1 Lost Revenue Adjustment Mechanism

The lost revenue adjustment mechanism variance account (LRAMVA) is a retrospective adjustment designed to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs. The OEB established Account 1568 as the LRAMVA to capture the difference between the OEB-approved CDM forecast and actual results at the customer rate class level.

On April 26, 2012, the OEB issued *Guidelines for Electricity Distributor Conservation and Demand Management* (2012 CDM Guidelines). The 2012 CDM Guidelines provide details on the LRAMVA for the 2011 to 2014 period. Accounting guidelines on the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the 2012 CDM Guidelines for further details.

On May 19, 2016, the OEB issued the *Report of the OEB on Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs* (the LRAMVA Report). The OEB updated its policy on how peak demand savings from energy efficiency and demand response programs should be treated for LRAMVA purposes. The OEB expects distributors to refer to the LRAMVA Report and follow the new policy.

In July 2016, the OEB developed a generic LRAMVA work form to provide distributors with a consistent approach to calculate LRAMVA. The LRAMVA work form consolidates information that LDCs have received from the IESO.

In December 2016, the OEB indicated in various decisions[15] that changes to an approved LRAMVA amount were not permitted. This policy affects the treatment of verified savings adjustments that can be claimed by distributors. If an LRAMVA amount was approved and disposed, the persistence of the savings adjustment(s) can only be

[15] EB-2016-0075 (Guelph Hydro 2017 IRM) and EB-2016-0080 (Hydro One Brampton 2017 IRM)

claimed on a "go-forward" basis.[16] LDCs cannot seek recovery of LRAMVA amounts related to savings adjustments for a year in which the corresponding LRAMVA amount has been approved by the OEB on a final basis. For example, if an LDC has received approval of its 2014 LRAMVA balance, excluding 2014 savings adjustments, the LDC must forgo any LRAMVA amounts related to the 2014 savings adjustments as the 2014 LRAMVA balance was approved by the OEB on a final basis.

2.4.6.2 Disposition of the LRAMVA

At a minimum, distributors must apply for the clearance of energy- and/or demand-related LRAMVA balances attributable to approved energy efficiency programs in a CoS application.

The distributor shall compare the OEB-approved LRAMVA threshold to actual CDM results at a rate class level. The variances 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 LRAMVA threshold and actual CDM results in the LRAMVA for the 2015-2020 period, as noted in the OEB's *Conservation and Demand Management Requirement Guidelines for Electricity Distributors*[17] (2016 CDM Guidelines).

As documented in the LRAMVA Report, DR3 (Demand Response 3) savings should generally not be included in the LRAM savings unless supported by empirical evidence being reviewed in the CoS application. Any requests for approval of lost revenues related to peak demand savings from demand response programs can only be part of a rebasing application due to the complexity and unique nature of the calculation of lost revenues from peak demand savings.

The following information should be provided in the application:

- A statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition
- A statement confirming that LRAMVA was based on verified savings results that are supported by the distributor's final CDM Annual Report and Persistence Savings Report issued by the IESO. (At the time of filing, a distributor may have only received the initial CDM report. The LRAMVA claim may be based on the information in that report at the time of filing of the application, but it is expected that the claim will be updated when the final report is issued, and that approved disposition will reflect the final report.) Reports must be filed in Microsoft Excel format.
- A statement indicating that the distributor has relied on the most recent input

[16] See EB-2016-0214 for an example (North Bay Hydro 2017 IRM)

[17] Originally issued on December 19, 2014, updated on August 11, 2016

assumptions available at the time of program evaluation

- A summary table showing the principal and carrying charges amounts by rate class and the resultant rate riders for each rate class. Projected carrying charges related to the disposition should be calculated in the LRAMVA work form.
- A statement confirming the period of rate recovery
- Rationale must be provided for disposing the balance in the LRAMVA, if one or more rate classes do not generate significant rate riders
- Details for the forecasted CDM savings included in the LRAMVA calculation including reference to the OEB's approval, or an explanation if there are no forecast CDM savings
- A statement explaining how the rate class allocations for actual CDM savings are determined by customer class and program for each year. Documentation (e.g. tables supporting the rate class allocations) should be filed in Tab 3-a of the LRAMVA work form.
- A statement confirming whether additional documentation or data was provided in support of projects that were not included in the LDC's Final CDM Annual Report (e.g. streetlighting projects). Distributors billing data by project must be included in the work form in Tab 8 of the LRAMVA work form, as applicable.
- For a distributor's streetlighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided:
    - Explanation of the methodology to calculate streetlighting savings
    - Confirmation whether the streetlighting savings were calculated in accordance with OEB-approved load profiles for streetlighting projects
    - Confirmation whether the streetlighting project(s) received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings

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 the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084) (the 2009 Report), issued December 11, 2009.

The OEB issues 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, with respect to the following:

- Long-term debt
- Short-term debt
- Preference shares
- Common equity

Explanations are required for material changes in actual capital structure or material differences between actual and deemed capital structure, 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 the proposed rate(s), including key assumptions

The cost of debt is a frequently contested area in applications. Notional debt is that portion of the deemed debt capitalization that results from differences between the distributor's actual debt and the deemed debt thickness of 60% (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, with regards to dividend policy (paying out earnings) versus 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 rather than the current deemed long-term debt rate issued by the OEB. This approach has been upheld in several decisions in recent years.[18]

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 (and thus no current or historical information on actual debt costs for the utility).

2.5.3 Not-for-Profit Corporations

In prior decisions, the OEB determined that applicants which are not-for-profit corporations may apply using the OEB's deemed capital structure and cost of capital.

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

- The requested capital structure
- The requested cost of capital (including the proposed cost of long-term and short-term debt and the proposed return on equity)
- A statement as to whether the revenues derived from the return on equity component of the cost of capital will be used to fund reserves (operating, capital, insurance, etc.) or will be used for other purposes
- If the revenues derived from the return on equity component of the cost of capital will be used to fund reserves, provide the specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied.

[18] December 19, 2014 (Updated August 11, 2016) Hydro One Remote Communities Decision with Reasons, EB-2008-0232, page 12, London Hydro Inc. Decision with Reasons, EB-2008-0235, pages 36-37

- If the revenues derived from the return on equity component of the cost of capital will be used for other purposes, provide a statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities). Provide rationale supporting the use of the revenues in this manner. Also provide the governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities.

If the applicant has approved reserves from previous OEB decisions, the applicant must also document the following:

- 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

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 keep 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 Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects, MIST meters) 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 filed in the application must be provided so that parties can easily map the summary cost driver information in this exhibit to the evidence elsewhere in the application that supports it.

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

2.6.1 Revenue Requirement Work Form

The RRWF is a live Microsoft Excel spreadsheet issued by the OEB along with these filing requirements that provides a high-level summary of the numbers in the application.

The RRWF also serves as a summary of the changes to the proposed revenue requirement through the stages of application processing. Applicants should also be mindful that the “Summary of Proposed Changes” (Tab 14: Tracking Form), summarizing cumulative changes to key results of the application is required. This tab must be completed and kept updated during the course of the application review process.

Beginning with 2017, the RRWF was expanded to include summaries of customer/connection and load forecast, cost allocation, rate design and revenue reconciliation data. These changes allow for the RRWF to calculate and present a summary of the proposed distribution rates, excluding any rate riders or rate adders. This has enabled elimination of some of the appendices, such as 2-P and 2-V, which are replaced by tabs in the RRWF. The RRWF thus serves as a cost of service rate generation model. However, it does not have the level of detail in models used by distributors in supporting their applications, and is not intended to replace them. It does serve as a summary used to check the proposed revenue requirement and the rates to recover it through the application process. If the enhanced RRWF cannot reflect a distributor’s proposed rates accurately, the distributor must file its rate generator model.

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 to be used in various Appendices and schedules as required and discussed elsewhere in Chapter 2 (e.g. Appendices 2-JA, 2-JB, 2-JC).

The RRWF must be filed in this exhibit in PDF format 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 reconcile with the appropriate numbers in other exhibits.

2.7 Exhibit 7: Cost Allocation

This exhibit includes information on cost allocation study requirements, class revenue requirements and revenue-to-cost ratios.

2.7.1 Cost Allocation Study Requirements

The OEB outlined its cost allocation policies in the OEB's reports of November 28, 2007 *Report of the Board on Application of Cost Allocation for Electricity Distributors*[19] and March 31, 2011 *Review of Electricity Distribution Cost Allocation Policy*[20] (the Cost Allocation Reports).

A completed cost allocation study using the OEB-approved methodology, or a comparable study and 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 is available on the OEB's website. Sheets 11 and 12 of the RRWF[21] must also be completed.

In a letter dated June 12, 2015, the OEB stated that it expected distributors to be mindful of material changes to load profiles and to propose updates in their respective cost of service applications when warranted. To date, most distributors have adjusted load profiles provided by Hydro One in their cost allocation studies. The Hydro One profiles were based on 2004 data, and consumption patterns may have changed since then due to factors such as technology, macroeconomic changes, conservation programs and time of use pricing. Distributors should make best efforts to update all classes' load profiles using the most recent available data, particularly from smart, MIST and interval meters. Recently, the OEB has required that load profiles for all classes be updated at the same time, not just selective updating.[22]

If a distributor is not able to update its load profiles at this time, an explanation should be provided and the distributor should confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed. In such cases, the load profiles provided by Hydro One for use in the original 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 has disappeared, or is forecasted to disappear in the test year. The cost allocation 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 the class load profile, and ensure consistency with the load forecast information as per section 2.3.2.

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[19] EB-2007-0667

[20] EB-2010-0219

[21] Sheet 11 is "Cost Allocation and Rate Design" and Sheet 12 is "New Rate Design Policy for Residential Customers." These replace the former Appendix 2-P and 2-PA.

[22] EB-2014-0002, Horizon Utilities Corporation, Decision and Order, December 11, 2014, p.6

The distributor must provide a spreadsheet and a description with example calculations to show how the demand data in the cost allocation model was derived from the load forecast and load profiles.

Distributors should refer to section 2.6.4 of the March 31, 2011 Cost Allocation Report concerning weighting factors for allocation of certain costs. Distributors are expected to develop their own weighting factors, and a description of the weighting factors is required. As explained in that report, if the distributor has chosen to use the default weighting factors, an explanation for this choice 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, whether using the OEB-issued one or a different model, with the application.

2.7.1.1 Specific Customer Class(es)

The following sections provide policy guidance on cost allocation matters for specific customer classes.

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 may have used in a previous rebasing 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 distributor 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 the RRWF.
- If the host distributor proposes to establish a new embedded distributor class, the host distributor must include that class in its cost allocation study and in the RRWF and provide rationale and supporting evidence for the establishment of an

Embedded Distributor class, as applicable. The host distributor must provide the costs of serving the embedded distributor(s), 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 the RRWF. 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 distributor(s), 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)

For allocation of costs related to unmetered loads, distributors should refer to the OEB's *Report of the Board on Review of the Board's Cost Allocation Policy for Unmetered Loads*, which amended section 2.4.6 of the DSC, and the OEB's letter of June 12, 2015, which outlined a 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.

The OEB expects distributors to document their communications with unmetered load customers, including street lighting customers, and how the distributor assisted 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.

MicroFIT class

The OEB does not expect a distributor to include microFIT as a separate class in the cost allocation model beginning in 2017. The OEB establishes a generic rate which can be adopted. The OEB has reviewed the generic rate for the 2019 rate year and will not change the current microFit rate. If an applicant believes that it has unique circumstances which would justify a different rate it must file appropriate documentation to support such a rate.

Standby Rates

A standby rate is charged by a distributor to a customer with load displacement facilities behind its meter to compensate the distributor for the cost of maintaining the ability to accommodate the total load of the customer at any time. The charge must not inadvertently subsidize other customers or unduly burden the load displacement customer.

Standby rates have been approved on an interim basis since 2006 for most distributors.

On April 2, 2015, the OEB issued a *Board Policy on Rate Design for Electricity Residential Customers* in which the OEB indicated that it intends to remove the standby charge when the new rate policy is implemented for commercial customers.

Distributors may still 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, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).

2.7.1.2 New Customer Class(es)

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

2.7.1.3 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 provide continuity of information, the distributor must restate information from its previous cost of service application concerning class revenue requirements in the RRWF on the basis of the proposed customer classes, where possible.

2.7.2 Class Revenue Requirements

The RRWF shows the format for filing cost allocation information in Sheet 11: Cost Allocation and Rate Design and includes four tables. The first table is the format for showing the test year class revenue requirements, which are 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.

Rate rebalancing is the process of adjusting rates for different customer rate classes in order to ensure that the revenues collected from each class reasonably reflect the costs to service customers in each class while ensuring the distributor recovers its overall revenue requirement. To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply 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 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 OEB has established ranges for revenue-to-cost ratios. The range of acceptable ratios is in section 2.9.4 of the March 31, 2011 Cost Allocation Report.

As per the OEB's letter of June 12, 2015, 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 December 19, 2013 *Report of the Board on Review of the Board's Cost Allocation Policy for Unmetered Loads*.

The third table on sheet 11 of the RRWF 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, and expressed as ratios 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 within a reasonable period of time. Moving revenues closer to costs in one class also means that there will be offsetting adjustments to one or more classes. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant. Applicants are also reminded of the OEB's policy that revenue-to-cost ratios should not be moved away from unity;[23] this may not always be possible when making adjustments overall, but applicants should explain their proposed adjustments and attempt to minimize variances from the OEB's policy.

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 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 account balances 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
- Retail Transmission Service Rates (RTSRs)
- Retail Service Charges
- Regulatory Charges
- Specific Service Charges
- Low Voltage Service Rates
- Loss Adjustment Factors
- Tariff of Rates and Charges
- Revenue Reconciliation
- Bill Impact Information

[23] EB-2007-0667, pp. 6-7

- Rate Mitigation

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 rate adders, funding adders and rate riders (e.g. LV, smart meter rate riders, Green Energy Act (GEA) and smart grid rate riders, deferral/variance account disposition).

2.8.2 Rate Design Policy

On April 2, 2015, the OEB released its *Board Policy on A New Distribution Rate Design for Residential Electricity Customers*,[24] 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, meaning that many distributors, including those filing rebasing applications for 2019, will be completing

[24] EB-2012-0410

their transition to fully fixed rates for residential customers for 2019.[25] 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. All distributors applying for 2019 rates are expected to file proposals to continue to implement this policy.

In proposing a transition to a fully fixed monthly service charge, the distributor must follow the approach set out in Tab 12 of the RRWF. 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.[26]

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.

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, subsequent updates to the Uniform Transmission Rates (UTRs) and any host distributor's rates. 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 per 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

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[25] Some distributors may require, and have received, OEB approval for one or two additional years to fully transition to 100% fixed distribution charges for residential customers due to rate mitigation in earlier applications from 2016 onwards.

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

Retail services refer to services provided by a distributor to retailers or customers related to the competitive supply of 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 adequate notice of proposed changes. Distributors should also include the results of any consultation in its application.

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 2.9.4.

2.8.5 Regulatory Charges

The Wholesale Market Service (WMS) rate is designed to allow distributors to recover costs charged by the IESO for the operation of the IESO-administered markets and the operation of the IESO-controlled grid.

The WMS rate is an energy-based rate (per kWh) applicable 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 WMS rate.

The Rural or Remote Electricity Rate Protection (RRRP) program is designed to reduce costs for eligible customers located in certain rural or remote areas where the cost of distributing electricity is higher.

The Standard Supply Service Charge is set by the OEB as an administrative fee payable by customers who purchase electricity directly from their distributor.

These rates are set by the OEB on a generic (i.e. province-wide) basis. Applicants should refer to the most recent rate order for the current approved rate. 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 a different rate, in addition to a detailed derivation of their proposed rate.

2.8.6 Specific Service Charges

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. Distributors must separately identify in the

Application 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.

The calculation of the charges must include 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 provide an explanation for the nature of the costs being recovered. A schedule outlining the revenues or capital contributions recovered from these rates and charges from the last OEB-approved year (both what was approved and the actual for that year) to 2017 and the revenue or capital contributions forecasted for the 2018 bridge and 2019 test years must also be provided, as well as a proposal and explanation as to 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).

Wireline Pole Attachment Charge

On March 22, 2018, the OEB issued its *Report on Wireline Pole Attachment Charges*,[27] updating its approach to wireline pole attachments.

The OEB has determined that it is in the public interest to set a province-wide wireline pole attachment charge of $43.63 per pole per year for each user. This new charge will apply to all licensed distributors that have not received OEB approval for a distributor-specific pole attachment charge. The OEB determined that, as a transitional measure, to mitigate the impact of the increase from the previous charge of $22.35 per pole per year for each user, a distributor without a distributor-specific charge will charge the province-wide pole attachment charge of $28.09 from September 1, 2018 to December 31, 2018. This charge will increase to $43.63 effective January 1, 2019. The pole attachment charge will then be adjusted annually based on the OEB's inflation factor commencing on January 1, 2020.

[27] EB-2015-0304

In a letter issued March 22, 2018, the OEB instructed distributors to record the excess incremental revenue as of September 1, 2018 until the effective date of its rebased rates in a new variance account related to pole attachment charges. Distributors will need to refund the closing balance in the distributor's next cost of service application. For 2019 CoS applications, the balance in this account will be out of scope.

A distributor may choose to use utility-specific costs and pursue a utility-specific pole attachment charge that better reflects their cost structure using the OEB's updated methodology. If a distributor chooses to apply for a custom charge, it must file a completed version of the OEB's Pole Attachment Workform and include the following information as part of their application:

- A statement confirming the proposed distributor-specific pole attachment charge, the year of data used, and when the proposed pole attachment charge will take effect
- A statement discussing the main cost drivers for changes to the pole attachment charge, including rationale for key changes
- A table summarizing the key inputs in the rate calculation, and a statement confirming that the RRR data (i.e. Account 1830, 5120) and pre-tax weighted cost of capital are consistent with the data filed in other cost of service models
- Confirmation of the total number of poles and joint use poles in the rate calculation, and a table outlining the rate of pole replacements and percentage of poles depreciated over the past five years
- Confirmation of the number of attachers that are specific to the distributor's service territory, if a different attacher number than the default number of 1.3 is proposed. A description of the types of attachments on poles, and a discussion of contractual arrangements with other entities that affect the number of attachments, including overlashing attachments, that are counted as part of the LDC's distribution poles
- Explanation of changes to the power deduction factor, if applicable, from the default power deduction factor of 15%. Distributors must complete Tab 4-a and explain the methodology to determine the distributor-specific power deduction factor. Distributors should provide supporting data and analysis, as applicable, in new tabs in the Pole Attachment Work Form or as additional attachments.
- Explanation of changes to the hybrid equal sharing allocation rate, if applicable, and the drivers of the proposed change
- Explanation of changes to the allocation factor of pole maintenance from Account 5120 to third party attachers, if the allocation factor is different than the default value of 48.5%. Table 8 in Tab 4 must be completed, and supporting analysis must be provided in new tabs in the Pole Attachment Work Form or as additional attachments.
- A description of the activities performed by the distributor to directly accommodate third party attachers. Distributors should include a discussion of the methodology, costs and data sources to calculate each component of direct costs. Distributors

should show the detailed calculations of total administration and loss of productivity (LOP) costs, including staff time and labour rates, as applicable.

2.8.7 Low Voltage Service Rates (where applicable)

If the distributor is (fully or partially) embedded, the distributor must provide the following information:

- Forecast of LV costs, which is the sum of the 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 forecasted 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 forecasted LV costs to customer classes (generally in proportion to transmission connection rate revenues)
- Proposed LV rates by customer class to reflect these costs

2.8.8 Smart Meter Entity Charge

On March 1, 2018, the OEB approved the application by the IESO, in its capacity as the Smart Metering Entity (SME), for a smart metering charge (SMC) for the 2018-2022 period. The OEB also issued a letter to all licensed electricity distributors outlining that the SMC is a pass through amount to be charged by distributors to all applicable customers in the Residential and General Service <50kW classes. The retail level charge appears as the Smart Metering Entity Charge on a distributor's tariff of rates and charges.

On March 23, 2018, the OEB issued updated guidance on the Smart Metering Entity Charge. Distributors must follow the accounting guidance provided in the OEB letter.[28]

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.

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[28] OEB Letter *Updated Guidance on Smart Metering Entity Charge*, dated March 23, 2018

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
- If the proposed distribution loss factor is greater than 5%, an explanation for the level of the loss factor, 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 in the Tariff Schedule and Bill Impacts model.

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 and charges on the Tariff of Rates and Charges to be approved by the OEB. Distributors may only charge rates that have been approved by order of the OEB. Proposed tariffs must include the applicable regulatory charges (i.e. WMC, Rural or Remote Electricity Rate Protection, and Standard Supply Service Administration charge), and any other generic rates such as the current SMC, as ordered by the OEB.

2.8.11 Revenue Reconciliation

With the proposed Tariff of Rates and Charges, the following information must be provided:

- Detailed calculations of revenue per customer class under current rates and proposed rates
- Detailed reconciliation of customer class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component, etc.)

A table to reconcile the base revenue requirement against the proposed rates must be provided. Previously this was Appendix 2-V, which has now been moved to and integrated into the RRWF in Sheet 13: Rate Design. The purpose of the revenue reconciliation is to check that the test year demand and the proposed rates recover the base revenue requirement to serve the forecasted customers and demand/consumption, subject to rounding. Rates and charges entered in the table on Sheet 13: Rate Design 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

This information must be filed for all customer classes in the Tariff Schedule and Bill Impacts model which identifies existing rates and proposed changes to rates, and calculates detailed bill impacts (including % change in distribution excluding pass-through costs (e.g. DVAs) – "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 into the Tariff Schedule and Bill Impacts model should be rounded to the decimal places as shown on the existing and proposed Tariff of Rates and Charges.

On April 14, 2016, the OEB issued the report *Defining Ontario's Typical Electricity Customer* in which it determined that the typical residential consumption that will be used for illustrative purposes should now be 750 kWh per month.

Bill impacts must be provided for a residential customer consuming 750 kWh per month, a residential customer consuming at the lowest 10th percentile of consumption (as described in 2.8.13), and a general service customer consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide bill impacts for a range of consumption levels that are relevant to their service territory for each customer class. A general guideline of consumption levels is provided in the Tariff Schedule and Bill Impacts model.

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 impact for such customer(s), and provide an explanation.

2.8.13 Rate Mitigation

A distributor is expected to review bill impacts to determine if measures should be implemented to smooth impacts resulting from the application. A mitigation plan, as discussed in section 2.8.13.2, must be filed if total bill increases for any customer class exceed 10%.

2.8.13.1 Residential Rate Design

In order to support the initial transition to fully fixed distribution rates, the OEB designed two tests to determine when a mitigation plan must be provided – a threshold test for the change in the fixed charge, and an overall bill impact test. The OEB is requiring distributors once again to calculate and report on the rate impacts of the change in 2018 so that mitigation strategies may be employed to smooth the transition for the customers most impacted, such as those that consume less electricity.

If, as a result of the transition to fixed rates, the monthly service charge would rise by more than $4 in a single year, a distributor is expected to apply to extend the transition period beyond four years. A distributor shall propose an alternative or additional strategy in the event that an additional transition year is insufficient. Consistent with OEB policy regarding rate mitigation, a distributor may propose as part of its application that no extension is necessary; such a position must be substantiated with reasons.

While the rate design is revenue neutral across the residential class, the impact on individual customers will vary with consumption. The OEB requires distributors to calculate the combined impact of the fixed rate increase and any other changes in the cost of distribution service for those residential RPP customers who are at the 10th percentile[29] of overall consumption, to a minimum of 50 kWh per month. 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 10th percentile; this 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 total bill impact of the elements proposed in this application is 10% or greater for RPP customers consuming at the 10th percentile, a distributor must file a plan to mitigate the impact for the whole residential class or indicate, with support, why such a plan is not required. The distributor will have the ability to propose the approach to mitigation,

[29] That is, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis.

including, but not limited to, the option to extend the transition to fixed rates over a longer period.

It is the OEB's expectation that, for mitigation as a result of the transition to fixed rates, distributors will propose strategies that target only the residential class to avoid any material cross-subsidy between classes. Beyond the issue of residential rate design specifically addressed in this section, distributors are reminded that they must file a mitigation plan if total bill increases for any customer class exceed 10%.

2.8.13.2 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:

- Identification of all customer classes or groups of customers that would experience increases in excess of 10% and the magnitude of these increases
- 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
- Any other information the distributor believes is relevant to its mitigation proposal

The distributor must ensure that the populated Tariff Schedule and Bill Impacts model reflects any mitigation plan proposed in the application.

2.8.13.3 Rate Harmonization Mitigation Issues

Distributors that have merged and that 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 justification in its plan as to why mitigation 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 deferral and variance accounts and sub-accounts with balances that have not been disposed of yet. The applicant must provide a brief description of any account that the applicant may have used differently than as described in the APH or another OEB document.
- A continuity schedule for the period from the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all outstanding deferral and variance accounts. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the Electricity Reporting and Record-keeping Requirements is to be provided in the DVA Continuity Schedule. A completed version of the DVA Continuity Schedule, available on the OEB's website, 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 confirm that it has used the rates established by the OEB by month or by quarter for each year. The rates that should be used are provided on the OEB's website. The most recently posted interest rate is used for any future periods.
- 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 (RRR) and documented in the applicant's Audited Financial Statements
- Identification of which Group 2 accounts the distributor proposes be continued and which it proposes be discontinued on a going-forward basis, with an explanation for these proposals
- Identification of any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account (see section 2.9.5). This must correspond with information provided in Exhibit 1 (see section 2.1.6).
- 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). The OEB expects that no adjustments will be made to any deferral and variance account balances previously approved by the OEB on a final basis. If adjustments were made, the applicant must provide explanations for

the nature and the amounts of 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, mapped to USoA account numbers. The distributor must reconcile the USoA numbers to the audited financial statements. If there are any differences 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 GA Charge into RPP and non-RPP portions. If this is not the case, the distributor must provide an explanation.
- A statement confirming that the commodity account balances proposed for disposition reflect:
    - Amounts that have been trued-up with the IESO (or host distributor) for the RPP related GA (IESO Charge Type 1142). This also means that the preliminary estimates related to tier 1, tier 2 and each TOU block are trued-up.
    - GA costs proportionate to actual RPP and non-RPP volume consumption (i.e. Charge Type 148 is reflected in the commodity accounts in proportion to actual RPP and non-RPP proportions)

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

For applicants that have already rebased under MIFRS[30] but have made further material changes since the adoption of IFRS on January 1, 2015 for audited financial statement purposes, these impacts should also be recorded in Account 1575, and an explanation provided. If no material changes were identified, the applicant should indicate the total dollar value of the change, explain why the change was not material, and provide a statement confirming that it has considered all possible impacts.

2.9.2 Retail Service Charges

If the distributor has 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 balance(s) in Account 1518 and/or Account 1548

[30] Including if the applicant has already rebased using the regulatory accounting changes under CGAAP for depreciation expense and capitalization policies. These changes were mandated by the OEB to be implemented by January 1, 2013.

- Provide a schedule identifying all revenues and expenses listed by USoA account numbers that are incorporated into the variances recorded in Account 1518 and/or Account 1548
- State whether or not the distributor has followed Article 490, Retail Services and Settlement Variances of the APH for Account 1518 and Account 1548. The distributor must provide an explanation and quantify the variance if the distributor has not followed Article 490, even if the distributor has zero balances in these accounts.

2.9.3 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 most current audited financial statements and provide explanations for any variances
- If the RRR balances do not agree to the year-end balances in the continuity schedule, a distributor must reconcile and explain the difference(s). For any utility specific accounts requested for disposition (e.g. Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived must be provided. The relevant accounting order must also be provided. Request final disposition of residual balances for vintage Account 1595 sub-accounts only once. Distributors are expected to seek disposition of the audited account balance a year after a rate rider's sunset date. No further transactions are expected to flow through the account (see Appendix A – Application of Recoveries in Account 1595 for more detail).
- Propose the mechanism for disposition with all relevant calculations:
    - The allocation of each account, including the rationale for the allocation. 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).
    - The proposed billing determinants, including 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
- Rate riders where the volumetric rider is $0.0000 for one or more classes must not be included on the tariff for those classes. The entire OEB-approved amount for recovery or refund will typically be recorded in a Uniform System of Accounts account to be determined by the OEB for disposition in a future rate setting.

- Propose rate riders for recovery or refund of balances for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period, an explanation must be provided.
- The DVA model should calculate the DVA disposition rate riders using the load data included in the load forecast section of the application.
- Establish separate rate riders to recover the balances in the RSVAs from wholesale market participants (WMP) who must not be allocated the RSVA account balances related to charges for which the market participants settle directly with the IESO (e.g. wholesale energy, wholesale market services).
    - A WMP refers to any entity that participates directly in any of the IESO-administered markets. These participants settle commodity and market-related charges with the IESO even if they are embedded in a distributor's distribution system. As a consequence, a distributor must not allocate any balances to these customers from Account 1580 RSVA – Wholesale Market Services Charge, Account 1580 Variance WMS, Sub-Account CBR Class B, Account 1588 RSVA – Power, and Account 1589 RSVA – Global Adjustment to a WMP.
    - A distributor must ensure that rate riders are appropriately calculated for the following remaining charges that are still settled with a distributor. These are Account 1584 RSVA – Retail Transmission Network Charge, Account 1586 RSVA – Retail Transmission Connection Charge and Account 1595 – Disposition/Refund of Regulatory Balances.
- Propose disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance.
    - In the DVA Continuity Schedule, applicants must indicate whether they serve any Class A customers during the period where the Account 1580 CBR Class B sub-account balance accumulated. If yes, a separate rate rider will be calculated in Tab 5.3 CBR B of the DVA Continuity Schedule. However, in the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580 CBR Class B sub-account will be added to the Account 1580 – WMS control account to be disposed through the general purpose Group 1 DVA rate riders. The balance in sub-account CBR Class B must be disposed over the default period of one year. If the distributor did not have any Class A customers during the period in which the Account 1580 CBR Class B sub-account balance accumulated, the DVA Continuity Schedule will also transfer the sub-account balance to the Account 1580 – WMS control account and include the CBR amounts as part of the general purpose Group 1 DVA rate riders.
    - Account 1580 sub- account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance.

- The DVA Continuity Schedule will also allocate the portion of Account 1580 sub-account CBR Class B to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be charged/refunded the general CBR Class B rider. Customers should be charged in a consistent manner for the entire rate rider period until the sunset date, regardless of whether customers transitioned between Class A and Class B during the disposition period.

2.9.3.1 Disposition of Global Adjustment Variance

Class B and A Customers

Most customers pay the 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 GA based on their percentage contribution to the top five peak Ontario demand hours (i.e. peak demand factor) over a year-long period.[31] Distributors that settle GA costs with Class A customers on the basis of actual GA prices shall allocate no GA variance balance to these customers for the period that customers were designated as Class A.

For Class B non-RPP customers, the GA 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 Class B customers. Effective in 2017, the billing determinant and all the rate riders for the GA will be calculated on an energy basis (kWh) regardless of the billing determinant used for distribution rates for the particular class. The DVA Continuity Schedule will calculate the GA rate riders on an energy basis.

The DVA Continuity Schedule will also allocate the portion of Account 1589 GA to customers who transitioned between Class A and Class B based on customer specific consumption levels. All transition customers will only be responsible for the customer specific amount allocated to them. They will not be charged/refunded the general GA rate

[31] 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. Effective January 1, 2017, the ICI expanded to include all electricity users with an average monthly peak demand over 1 MW. In April, 2017, the ICI further reduced the ICI threshold to 500 kW to make targeted manufacturing and industrial sectors, including greenhouses, eligible to opt-in to the ICI.

rider. Customers should be charged in a consistent manner for the entire rate rider period until the sunset date, regardless of whether customers transitioned between Class A and Class B during the disposition period.

GA Analysis Workform

Starting for the 2018 rate applications, all distributors must complete the GA Analysis Workform. The new workform will help the OEB assess if the annual variance recorded in Account 1589 is reasonable. The workform compares the general ledger principal balance to an expected principal balance based on monthly GA volumes, revenues and costs.

A discrepancy between the actual and expected balance may be explained and quantified by a number of factors, such as an outstanding IESO settlement true-up payment. The explanatory items should reduce the discrepancy and provide distributor-specific information to the OEB. Any remaining, unexplained discrepancy will be assessed for materiality and could prompt further analysis before disposition is approved. Unexplained discrepancies should be calculated separately for each calendar year. Any unexplained discrepancy for each year greater than +/- 1% of total annual IESO GA charges will be considered material.

The GA Analysis Workform is included in the DVA Continuity Schedule on the OEB's website and is to be filed in live Microsoft Excel format.

Description of Settlement Process

A distributor must support its GA claims with a description of its settlement process with the IESO or host distributor.

The description should include the following:

- The GA prices the distributor uses to bill (and record unbilled entries) to its various customer classes (i.e. 1st estimate, 2nd estimate or actual). Confirm that the GA rate that is used is applied consistently for all billing and unbilled revenue transactions for non-RPP Class B customers in each customer class. In addition, where the same GA rate is not used for non-RPP Class B customers in all customer classes, explain what GA rate is applied to each customer class.

- The distributor's process for providing consumption estimates to the IESO as part of its RPP settlement process and the RPP settlement process used to true-up estimated amounts to actual amounts. Specifically, the distributor should indicate what type of data is used to determine the volume estimates of RPP customers at different TOU periods or Tier 1 and 2 blocks. A distributor must also provide the timing of actual data when it becomes available and the subsequent true-up process.

- The distributor's method for estimating RPP and non-RPP volume consumption, as well as its treatment of volumes related to embedded generation or embedded distribution customers

- The distributor's internal control tests, if any, in validating estimated and actual consumption figures used in its RPP settlement process and subsequent true-up adjustments

Distributors are reminded that they are expected to use accrual accounting.

Description of Accounting Methods and Transactions for each Year in which the Applicant is requesting the Balances for Disposition

A distributor must provide the OEB with a description of its financial accounting practices as they relate to its recording of transactions in commodity accounts 1588 and 1589. In addition, a distributor must disclose the nature, timing, and dollar impact of any subsequent adjustments recorded after the reporting period that adjust the initial transactions from preliminary estimates to actual figures based on consumption data. In addition, distributors must complete Tab X in the GA Analysis Workform for each applicable fiscal year subsequent to the most recent year in which Group 1 Accounts were approved for disposition on a final basis by the OEB.

If a distributor uses the actual GA price to bill non-RPP Class B customers for an entire rate class, it must make a proposal to exclude these customer classes from the allocation of the balance of Account 1589 RSVA GA and the calculation of the resulting rate riders. These rate classes are not to be charged/refunded the GA rate rider as they did not contribute to the accumulation of the balance of Account 1589 RSVA GA.

2.9.3.2 Commodity Accounts 1588 and 1589

RPP Settlement True-up

Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589*, applicants must reflect RPP Settlement true-up claims pertaining to the period that is being requested for disposition in the RSVA Power (Account 1588) and RSVA GA (Account 1589) variance accounts. In doing so, distributors are to follow the guidance provided in the above noted letter.

Certification of Evidence

Given issues that have arisen with commodity accounts 1588 RSVA Power and 1589 RSVA GA balances, the OEB now requires a certification by the Chief Executive Officer

(CEO), or Chief Financial Officer (CFO), or equivalent. The application must include a certification that the distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed, consistent with the certification requirements in Chapter 1 of the filing requirements.

2.9.4 Establishment of New Deferral and Variance Accounts

In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:

- Causation. The forecasted expense must be clearly outside of the base upon which rates were derived.
- 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.
- Prudence. The nature of the costs and forecasted quantum must be based on a plan that sets out how the costs will 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.

Appendix A: Application of Recoveries in Account 1595

When approval for disposition of deferral and variance account balances is received from the OEB, the approved amounts of principal and interest carrying charges is transferred to Account 1595 for that rate year.

Applicants are expected to request disposition of residual balances in Account 1595 sub-accounts for each vintage year only once. Distributors are expected to seek disposition of the audited account balances a year after a rate rider's sunset date has expired. No further transactions are expected to flow through sub-account 1595 once the residual balance has been disposed. The 1595 sub-accounts for each vintage year are to be disposed only once on a final basis. No further dispositions of these accounts are expected thereafter unless justified by the distributor.

1595 Analysis Workform

Starting for the 2019 rate applications, distributors who meet the requirements for disposition of residual balances of Account 1595 sub-accounts, must complete the 1595 Analysis Workform. The new workform will help the OEB assess if the residual balances in Account 1595 sub-accounts for each vintage year are reasonable. The workform compares principal and interest amounts previously approved for disposition to the residual balances remaining after amounts have been recovered/refunded to customers through rate riders.

Initially, residual balances will be assessed for materiality and could prompt further review before disposition is approved. Balances in Account 1595 will first be assessed in two groups of accounts: one being the amounts attributable to GA, and the other being the remainder of Group 1 and Group 2 Accounts (if applicable). A residual balance in either of the two groups of accounts exceeding +/- 10% of the original amounts previously approved for disposition would be considered material. Material residual balances will require further analysis, consisting of separating the components of the residual balances by each applicable rate rider[32] and by customer rate class. Distributors are expected to provide detailed explanations for any significant residual balances attributable to specific rate riders for each customer rate class. Explanations must include, for example, volume differences between forecast volumes (used to calculate the rate riders) as compared to actual volumes at which the rate riders were billed.

The 1595 Analysis Workform is available on the OEB's website and is to be filed in live Microsoft Excel format.

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[32] Residual account balances will be made up of amounts relating to at least two rate riders (i.e. the GA Rate Rider and the DVA Rate Rider)