Orientation Session for Electricity Distributors Rebasing for 2015 Rates

AGENDA

Ontario

Ontario Energy Board, 2300 Yonge Street, Toronto, Ontario
West Hearing Room, 25th Floor

July 24, 2014		
8:45	Welcome and Meet Your Case Manager	Lynne Anderson
9:00	Striving for Excellence	Rosemarie Leclair
9:30	The Role of The Registrar - What it is and what does it mean for the application process - Review of the Board's updated rules and practice directions	Kristi Sebalj
10:00	The Applications Process - A review of the hearing process, COS application timelines, and the new role of Board staff	Maureen Helt
10:30	Refreshment Break	
10:45	Filing Requirements - Summary of key changes	Martin Davies
11:15	New Policy Options - Review of proposed policies and how they may impact CoS applications	Keith Ritchie
11:45	Lunch Break (provided)	
12:30	Customer Engagement Activity - Review of the requirements and the new appendix	Birgit Armstrong
1:00	Consolidated Distribution System Plans - Keys to success and avoidance of common pitfalls	David Richmond Nabih Mikhail
1:30	Treatment of REG Investments - Review of the requirements and updated COS appendix on direct benefits	Harold Thiessen
2:00	Load Forecasting - Including the treatment of CDM impacts	Keith Ritchie
2:30	Refreshment Break	
2:45	Setting Rates using MIFRS - Review of requirements for 2015 filers and Ch. 2 appendices	Donna Kwan
3:15	Cost Allocation and Rate Design - Review of what has changed since last rebasing	Vince Cooney
3:45	Intervenors' Perspective - How intervenors assess applications	Jay Shepherd
4:15	Questions on other topics and closing comments	Ted Antonopoulos
4:30	End	

2015 Cost of Service Rebasing Rates Orientation - July 24, 2014
Ontario Energy Board
Attendees

1)	**E**ssex Powerlines Corporation	Michelle Soucie	msoucie@essexpower.ca
2)	**E**ssex Powerlines Corporation	Richard Dimmel	rdimmel@essexpowerlines.ca
3)	**F**estival Hydro Inc.	Debbie Reece	dreece@festivalhydro.com
4)	**G**uelph Hydro	Cristina Birceanu	cbirceanu@guelphhydro.com
5)	**H**alton Hills	Tracy Rehberg-Rawlingson	tracyr@haltonhillshydro.com
6)	**H**ydro Ottawa	Jane Scott	janescott@hydroottawa.com
7)	**K**ingston Hydro Corp.	Sherry Gibson	sgibson@utilitieskingston.com
8)	**K**ingston (Utilities Kingston)	Jim Miller	jmiller@utilitieskingston.com
9)	**N**iagara Penninsula Energy Inc.	Paul Blythin	Paul.Blythin@npei.ca
10)	**N**iagara Peninsula Energy Inc.	Suzanne Wilson	Suzanne.Wilson@npei.ca
11)	**N**iagara Peninsula Energy Inc.	Brian Wilke	Brian.wilke@npei.ca
12)	**N**orth Bay Hydro	Melissa Casson	mcasson@northbayhydro.com
13)	**N**orth Bay Hydro	Bruce Bacon	bbacon@blgcanada.com
14)	**O**rillia Power Corporation	Pauline Welsh	pwelsh@orilliapower.ca
15)	**O**ttawa River Power Corporation	Jane Wilkinson-Donnelly	jwilkinson@orpowercorp.com
16)	**O**ttawa River Power Corporation	Manuela Ris-Schofield	manuela@tandemenergyservices.ca
17)	**P**owerStream Inc.	Vitalika Quenville	vitalika.quenville@powerstream.ca
18)	**P**owerStream Inc.	Larry Iwamoto	larry.iwamoto@powerstream.ca
19)	**P**owerStream Inc.	Alison Price	alison.price@powerstream.ca
20)	**P**owerStream Inc.	Tamar Heisler	tamar.heisler@powerstream.ca
21)	**T**oronto Hydro-Electric System Limited	Daliana Coban	dcoban@torontohydro.com
22)	**T**oronto Hydro-Electric System Limited	Anthony Lam	alam@torontohydro.com
23)	**W**aterloo North Hydro Inc.	Chris Amos	camos@wnhydro.com
24)	**W**aterloo North Hydro Inc.	Alyson Conrad	aconrad@wnhydro.com
25)	**W**aterloo North Hydro Inc.	Albert Singh	asingh@wnhydro.com
26)	**W**ellington North Power	Ken Robertson	krobertson@checenergy.ca
27)	**W**ellington North Power	Judy Rosebrugh	jrosebrugh@wellingtonnorthpower.com
28)	**W**ellington North Power	Richard Bucknall	rbucknall@wellingtonnorthpower.com
29)	**W**hitby Hydro Electric Corporation	Ramona Abi-Rashed	RABI@whitbyhydro.on.ca
30)	**W**hitby Hydro Electric Corporation	Cindy Perrin	cperrin@whitbyhydro.on.ca
31)	**W**hitby Hydro Electric Corporation	Mike Chase	mchase@whitbyhydro.on.ca

2015 Cost of Service Applications
Case Managers

Distributor	Docket Number	Case Manager [1]
January 1 Rate Year		
Algoma Power Inc.	EB-2014-0055	Suresh Advani
Festival Hydro Inc.	EB-2014-0073	Birgit Armstrong
Hydro One Brampton Networks Inc.	EB-2014-0083	Martha McOuat
St. Thomas Energy Inc.	EB-2014-0113	Stephen Vetsis
May 1 Rate Year		
Hearst Power Distribution Company Ltd.	EB-2014-0080	Martha McOuat
Niagara Peninsula Energy Inc.	EB-2014-0096	Keith Ritchie
North Bay Hydro Distribution Ltd.	EB-2014-0099	Marc Abramovitz
Ottawa River Power Corporation	EB-2014-0105	Birgit Armstrong
Woodstock Hydro Services Inc.	EB-2014-0125	Kelli Benincasa

[1] This information is preliminary and may be subject to change.

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

Orientation Session
Electricity Distributors Rebasing for 2015 Rates
The Role of the Registrar

Kristi Sebalj, Registrar
July 24, 2014

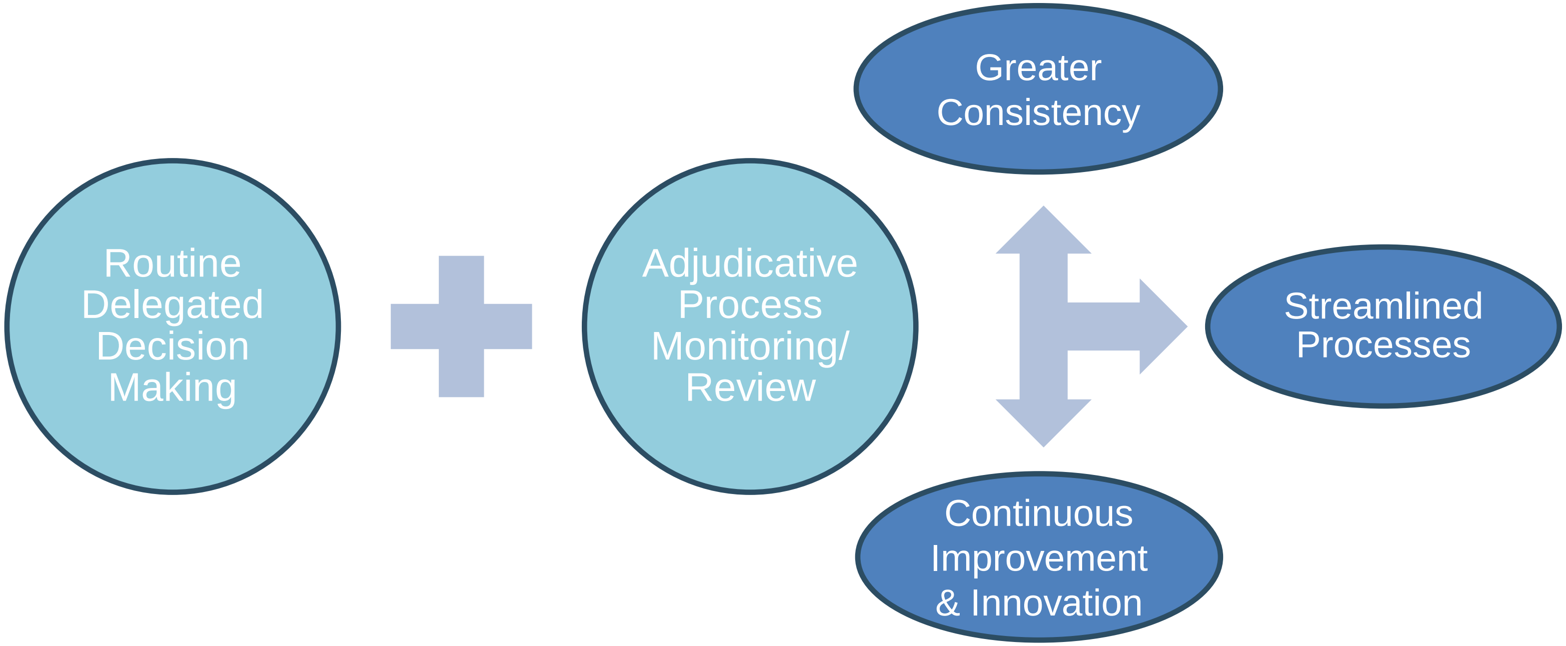
Agenda

1. Review of Registrar Role

2. Review of updated Rules and Practice Directions

3. Questions

Registrar


Routine Delegated Decision Making
Adjudicative Process Monitoring/ Review
Greater Consistency
Streamlined Processes
Continuous Improvement & Innovation

Registrar – Delegated Decision Making

- Routine delegated decision-making

- All applications that are not otherwise delegated under s. 6(1)

  - Issue notice
  - Issue PO#1

Registrar – Delegated Decision Making

- Notice
  - Determination of appropriate publication
  - Receive, consider and grant/refuse requests for:
    - intervenor status
    - cost eligibility

- Issue PO#1
  - Decision with respect to intervenor and cost eligibility requests
  - Set out procedure for hearing up to end of discovery
    - Guidance on RRFE expectations
    - Intervenor attendance
    - Issues list process following discovery

Registrar – Adjudicative Process

- Support and enhance regulatory efficiency/consistency by:
  - Monitoring adjudicative process
  - Identifying and address process related issues
  - Ensuring the Board's processes are serving the needs of all participants (Board, staff, stakeholders, applicants, intervenors)
  - Review and amend Rules and Practice Directions as/when necessary
  - Innovating where better processes are known/identified

Updated Rules and Practice Directions

- Over the past two years, the Board has reviewed the way it exercises its mandate through adjudicative proceedings, including:
  - process for rate hearings
  - access to proceedings
  - the role of Board staff
- A review of our application process and experience from recent proceedings highlighted the value of revising the Board's *Rules* and *Practice Directions* to provide guidance to applicants and stakeholders and facilitate consumer access to our proceedings

Key Changes - Rules

PURPOSE	CHANGE	AMENDMENT TO
To improve transparency of and stakeholder access to information on parties that intervene regularly.	Parties file information about their organization and representative(s) for posting on the Board's website.	*Rules (22.03(b))* *Practice Direction on Cost Awards (3.03.1)*
Provide stakeholders with web-based access to proceedings.	Stakeholders can sign up through the Board's website to monitor a Board proceeding.	*Rules (9.03)*
Increase efficiency in participation in proceedings.	Observer status eliminated. Still able to follow a proceeding on the website.	*Rules*

Key Changes - Rules

PURPOSE	CHANGE	AMENDMENT TO
Consistency in information filed when amendments to evidentiary record are made.	New and explicit requirements with respect to changes to the evidentiary record.	*Rules (11)*
Ensure a complete record.	Applicant must address the issues raised in letters of comment by way of a document filed in the proceeding.	*Rules (23.03)*
Efficiency/consistency in discovery.	Specific requirements for interrogatories and responses which are consistent across applications.	*Rules (26.02)*

Key Changes – Cost Awards

PURPOSE	CHANGE	AMENDMENT TO
To improve cost claim information on: - effort by activity and - intervenor collaboration.	Eligible parties provide better information in support of their cost claim .	*Practice Direction on Cost Awards (5.01 + new claim form)*
To clarify cost eligibility criteria on the interests represented by eligible parties.	Parties are eligible to apply for a cost award if the interest or policy perspective represented is relevant to the Board's mandate and to the subject proceeding.	*Practice Direction on Cost Awards*
To improve cost claim information on: - effort by activity and - intervenor collaboration.	Eligible parties provide better information in support of their cost claim .	*Practice Direction on Cost Awards*

Key Changes – Settlement Conferences

PURPOSE	CHANGE	AMENDMENT TO
Increase clarity of settlements.	Requirement to provide evidence and rationale for settlements.	*Rules (30.03)*
Clarify role of Board staff in settlement conferences.	Board staff to make submission on settlement proposals (whether settlement represents an acceptable outcome and whether the rationale is adequate) and in some circumstances be a party to the settlement.	*Practice Direction on Settlement Conferences*
Clarify status of parties that do not participate in settlement conference.	Except with leave of the Board a late intervenor or party that did not participate in the settlement conference cannot oppose it.	*Practice Direction on Settlement Conferences*

Questions

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Orientation Session
Electricity Distributors Rebasing for 2015 Rates

The Applications Process

Maureen Helt, Legal Counsel
July 24, 2014

Applications and Hearing Process Review

- In 2012, the Board initiated a review of its applications and hearing process, and engaged Optimus|SBR to assist.
  - *Changes implemented over the last two years (new notice, checklists, technology in hearing room, protocols for testing models, orientation sessions for applicants, hearing timeline changes, pilots)*
  - *Some changes reflected in filing requirements (materiality , MD&A and executive summary, clarifying RRFE language)*
  - *Some changes reflected in recent processes for reviewing and hearing an application (issues list after discovery)*
- A number of pilots were completed for 2013 applications
  - *Untranscribed teleconference before interrogatories*
  - *Staff interrogatories first, then intervenors*
  - *Intervenor interrogatories first, then staff*
- The offline teleconference was used in two more applications for 2014 rates
- While there is a "typical" process, the Board may revise for specific circumstances or to pilot other approaches
- The Board has concluded there should be greater use of pre-hearing conferences before oral hearings

Steps in a written hearing

Cost of service written hearings include:

- Notice
- Filing and testing evidence
- Settlement conference
- Submissions (if needed)
- Decision
- Rate Order

OEB Act requires a hearing unless no-one is materially affected by the application. Hearings can be written or oral.

Typical timeline for written hearing

Application Filed - Day 0

Notice - Day 23

P.O.# 1 - Day 50

Completion of Record - Day 150

Decision - Day 185

Rate Order - Day 230

Application filed

Application Filed - Day 0

August 29

Check for completeness

If application doesn't meet filing requirements, application cannot be processed without further evidence – we will specify

Note: letter of acknowledgement does not mean application is accepted as complete.

Notice issued

Notice - Day 23

September 22

If application is complete, notice is issued with directions for service

Typical requirements: newspaper publication, service on previous intervenors, post on website

If application not complete, process clock stops until necessary evidence filed.

Notice period

Notice - Day 23

September 23 – October 14

Intervention and letters of comment are received

Once publication is complete:

- File pdf version of “completed” notice that includes deadline for interventions
- File affidavit of service to prove notice given as directed

OEB has to wait for intervention period to expire before taking the next step.

Creating a record

P.O.# 1 -
Day 50

October 20

Several options for creating an evidentiary record

- Initial process set out by Registrar in Procedural Order #1

Options include:

- Interrogatories
- Technical conference

Choice determined by nature of application.

Testing evidence – typical steps

The goal is one round of discovery

As the approach under RRFE continues to evolve, two rounds of discovery may be needed

Typical timelines:

Timelines	
Interrogatories issued:	October 24
Responses to IRs due:	November 14
2nd round of IRs or Technical Conference:	November 28
Response to 2nd round of IRs or undertakings received	December 5

Testing evidence - options

- Pre or post IR discussion or untranscribed technical conference (live or by phone)
  - *Useful for clarifying understanding of evidence – may need filings to follow up*
- Sequential IRs: Board staff (or intervenors) ask IRs, answers received, then intervenors (or Board staff) ask IRs
  - *Useful for specific technical areas, but may take extra time*

ADR – Settlement proposal

Nearly all cost of service hearings include ADR – many have reached full settlements

- Board may exclude certain issues from settlement
- ADR: ~1 week after the second round of discovery complete (e.g. IR answers)
- Proposed settlement filed: ~2 weeks later
- Board acceptance / rejection or questions (oral or written) in considering the public interest: ~2 weeks after settlement proposal filed

If no ADR – go to submissions.

ADR – Staff's Role

Staff will be a party when there are less than two intervenors. Otherwise staff will continue in its role as an active participant who is not a party to the settlement.

- Staff will continue to raise policy issues for the parties to consider in their negotiations
  - ✓ if the policy matters remain outstanding or staff is concerned about the application of a policy, staff will include this in its submission following the filing of the agreement, as per the normal course

- Staff will continue to remind parties to set out in the Settlement Agreement sufficient rationale for the proposed settlement of each issue
  - ✓ Staff will continue to assist during the drafting phase as required

ADR – Staff's Role

What is New:

- Submissions: Staff will file a submission on any proposed settlement agreement, regardless of whether there are policy issues at play or not.
  - ✓ In the submission, if staff has concerns it may opine on the monetary or financial outcomes of the settlement agreement or the reasons for the position taken.
  - ✓ As with policy matters, staff will raise any concerns with the quantum during the settlement discussions for the parties to consider (this is so that there are no surprises when staff files its submission)

- Rationale: while sufficient rationale and "value for money" are not new concepts in ADRs, staff will remind parties that the rationale for proposals must focus on value and outcomes (including any long term impacts), as opposed to just costs.
  - ✓ Staff will encourage parties to assess and describe the proposal from the perspectives of:
    - delivering value for customers;
    - maintaining a sound business plan, both financially and operationally;
    - ensuring consistency with Board's policies.

- Unless any concerns have been identified during the discussions, staff's submissions are expected to be a short generic statement.

Submissions

Submissions necessary if no full settlement achieved

Typical order of submissions:

- Board staff submission
- Intervenors' submissions: ~3 days to 1 week after Board staff
- Applicant's reply ~2 weeks later

Can have argument in chief by applicant before Board staff if evidence has changed significantly during hearing or requests need clarification.

The Board can determine that it will hold an oral hearing before written submissions

Hearing complete

Completion of Record - Day 150

January 26

The record (including the settlement proposal and any submissions) should be completed.

Depends on whether there were:

- 2 rounds of discovery
- any elements settled shortening the time for submissions
- other extra steps needed (motions, intervenor evidence, etc)

Decision

Decision - Day 185

March 2

Written decision scheduled to be issued – this is the date on the metric on the OEB website.

Draft rate order

A draft rate order must be prepared in accordance with the decision

Steps in review:

- Draft rate order filed ~2 weeks after decision
- Board staff and intervenor comment ~1 week after draft order filed
- Reply to comments ~1 week later

Rate order

Rate Order - Day 230

April 16

Rate Order with the Tariff of Rates and Charges scheduled to be issued.

Oral hearing – additional steps

The following steps may be added in an oral hearing:

- Issues conference
- Procedural and motions day
- Pre-hearing conference
- Oral cross-examination
- Oral or written submissions
- Standard timeline: 280 days to decision plus rate order

Oral hearing protocol

- Board members hear the testimony of witnesses in the formal hearing room
- Parties cross-examine the witnesses
- Hearings are public (rare exceptions) and recorded by a court reporter, who must hear everything a witness says
- Applicants are required to provide a person to display their Exhibits on the hearing room monitors (training will be available)

Tips:

- Business attire
- Stand when Board panel enters or exits
- No food (coffee OK, but not when testifying!)
- No cell phones

Questions?

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Orientation Session
Electricity Distributors Rebasing for 2015 Rates

Cost of Service Filing Requirements
Summary of Key Changes

Martin Davies, Project Advisor, Electricity Rates and Accounting
July 24, 2014

2015 Rebasing List - Status

2015 COS

Algoma Power
Festival Hydro
Hydro One Brampton
St. Thomas Energy
Attawapiskat Power
Fort Albany Power
Hearst Power
Kashechewan Power
Niagara Peninsula Energy
North Bay Hydro
Woodstock Hydro

2016 COS

Grimsby Power
Guelph Hydro
Hydro Ottawa
Whitby Hydro
Orillia Power
Essex Powerlines
Waterloo North
Wellington North

Price Cap IR - May 1
Price Cap IR- Jan 1

Introduction

- Rate Applications and Hearing Process Review (APR) initiated June 2012
- Renewed Regulatory Framework for Electricity (RRFE) Report issued October 2012
  - All 2015 applicants subject to RRFE
- LDCs with a May 1 rate year
  - application deadline is August 29, 2014
  - For an effective date after May 1, distributors should submit their applications in a timely manner giving due consideration to the Board's timelines.
- Chpts 1, 2, 3 & 5 make up Dx rate applications compendium
  - Chapter 1: Overview applicable to all Dx rate applications
  - Chapter 2: Cost of Service Filing Requirements
  - Chapter 3: Incentive Rate-setting Filing Requirements
  - Chapter 5: Consolidated Distribution System Plan Filing Requirements

Substantive Changes

1. Administrative
2. Consolidation of Key Policy Statements and Learnings from Previous Year
3. New Requirements Arising From RRFE
4. Revisions Arising From APR (first implemented for 2014 applications)
5. MD&A/Executive Summary Distinctions
6. Revisions to Certain Other Existing Information Requirements

Administrative

- Focus on not repeating content of existing Board documents (chapters 1 & 2)
  - Chapter 1 revised to acknowledge recent updates to the *Rules of Practice and Procedure.*
    - Detailed discussion of filing of interrogatories has been removed with applicants required to consult *Rules of Practice and Procedure.*

- Formatting changes
  - Style, fonts, certain sections moved

Consolidation of Key Policy Statements and Learnings from Previous Year

- 2.3 General Requirements
  - New sections on Performance Evaluation and Scorecard and Corporate Governance
- Exhibit 2 (Rate Base)
  - Chapter 5 - Consolidated Distribution System Plans
    - Focus on good planning
    - Assessed on the basis of all 5 years of the DSP
    - Direct link between AMP and proposed test year budget
    - Applications not demonstrating good planning may not be further considered by the Board pending the filing of additional information supporting the application
    - Mandatory filing for distributors

Consolidation of Key Policy Statements and Learnings from Previous Year (cont'd)

- Exhibit 2 (Rate Base) – Other
  - Distributors wishing to propose an approach for the funding of capital as outlined in the Board's consultation on capital funding policy options may do so in their 2015 rate applications.
- Exhibit 7 (Cost Allocation)
  - Embedded distributor class
    - Revised to reflect December 2013 report on the treatment of embedded distributors
- Exhibit 8 (Rate Design)
  - Fixed Charges
    - Distributors wishing to propose a fixed monthly charge as outlined in the Board's rate design consultation may do so in their 2015 rate applications.
  - Specific Service Charges - Monthly billing
    - Distributors can propose initiatives to reduce costs of transitioning to monthly billing (e.g. a credit charge for customers who opt for a paperless bill)
    -

Performance Evaluation

- The Scorecard
  - On March 5, 2014, the Board issued its EB-2010-0379 *Report of the Board on Performance Measures for Electricity Distributors: A Scorecard Approach*
  - Sets out the Board's policies on the measures that will be used to assess a distributor's effectiveness and improvement in achieving the four outcomes
  - The Scorecard is the form and implementation of the Board's performance monitoring tool
  - Distributor should discuss:

    (1) performance in relation to the Board's performance outcomes over the last five years, at the current point in time and projections for continuous improvements over the term of the application;

    (2) how the distributor's self-assessment has informed its business plan and the application and describe what measures are planned to achieve further continuous improvement including any short, medium and long distance performance targets that are being set by the distributor for itself.

New Requirements Arising From RRFE

- Introduction
  - New wording to explain the lens that should be used in preparing an application
- Exhibit 1 (Administrative Documents)
  - Management Discussion and Analysis required
  - New Appendix 2-AC summary of engagement activities and initiatives
- Exhibit 4 (Operating Expenses)
  - New wording to focus examination on business cases as opposed to individual activities

Revisions Arising from APR (first implemented for 2014 applications)

- Materiality
  - Chapter 1
    - Focus on exploration through the discovery process of material issues
    - Excessive detail of non-material issues to be considered at cost awards
  - Chapter 2
    - OM&A and Rate Base thresholds unchanged
    - New for 2015: Variance analysis on OM&A “programs” required only for outliers
    - 5% threshold established for explanations of DVA with certain exceptions (exhibit 9)
- Letters of Comment
  - Chapter 2
    - All responses to matters raised in letters of comment are to be filed with the Board during the course of the proceeding (exhibit 1)

Revisions Arising from APR (cont'd)

- Executive Summary
  - Chapter 2
    - New requirement since you last rebased, to replace Overview of Filing (exhibit 1)
- Bill impacts
  - Distributor only impacts excluding pass throughs for notice (exhibit 1)
- Clarity of Expectations
  - Language changes to be clear on what is required

MD&A/Executive Summary Distinctions

- MD&A
  - Business plan should describe both goals and plans to meet them
  - Fundamental elements to whether objectives are appropriately aligned with customer preferences and deliverability of goals
  - Plain language information about objectives and business plan and how these relate to the application and align with critical RRFE objectives
  - Applicant should also state whether its objectives have changed and how the plan to deliver on certain goals reflects customer feedback
  - Should include a broad utility overview/past and expected performance impacts

MD&A/Executive Summary Distinctions (cont'd)

- Executive Summary
  - Format is a brief summary of the key elements of the application:

A:	Revenue Requirement
B:	Budgeting and Accounting Assumptions
C:	Load Forecast Summary
D:	Rate Base and Capital Plan
E:	Operations, Maintenance and Administration Expense
F :	Cost of Capital
G:	Cost Allocation and Rate Design
H:	Deferral and Variance Accounts
I:	Bill Impacts

Revisions to Certain Other Existing Information Requirements

- Accounting changes
  - To address issues in previous applications and clarify expectations
  - ASPE and USGAAP no longer referenced
  - Reduced filing requirements for LDCs that have no further impacts arising from the transition to IFRS
  - IFRS transition cost deferral account to be disposed with forecast to 2015
- Renewable Energy Generation (REG) Investments
  - Draft Accounting Order for “IESO Revenues” Variance Account required
  - Modified Appendix 2-FA/FB
- Load Forecast
  - New Appendix 2-IA Summary and Variances of Actual and Forecast Data required
  - Revised section on CDM Adjustment and Appendix 2-I (exhibit 3)
- CDM
  - Modified to take into account the new CDM target period

Revisions to Certain Other Existing Information Requirements (cont'd)

- PILs
  - For rate-setting purposes, applicants should maximize tax credits and take the maximum deductions allowed
- RRWF
  - New section to explain its purpose. New component has been added for tracking changes to revenue requirement after every major step of a proceeding
- Tariff of Rates and Charges
  - Requirement for tracked changes version of current tariff sheet no longer required (exhibit 8)
- Seeking Approval to Align Rate Year with Fiscal Year
  - Discussion of rationale no longer required.

Revisions to Certain Other Existing Information Requirements (cont'd)

- Not-for-Profit Corporations
  - Applicants that are not-for-profit corporations shall retain the excess revenue in excess of costs only for the purpose of meeting the need to build up appropriate operating and capital reserves
  - Once the appropriate limits for these reserves have been achieved, an application seeking a rate adjustment would be expected
  - Additional information as to expected documentation has been incorporated into this year's update.

Questions

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

VT INCEPIT FIDELIS SIC PERMANET
Ontario

Ontario Energy Board

Filing Requirements
For
Electricity Distribution Rate Applications
- 2014 Edition for 2015 Rate Applications -

Last Revised on July 18, 2014
(Originally issued on November 14, 2006)

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

Ontario Energy Board

Filing Requirements For
Electricity Distribution Rate Applications
- 2014 Edition for 2015 Rates Applications -

Chapter 1

Overview

July 18, 2014

Chapter 1 Overview

This document provides information about the filing requirements for electricity distribution rate applications. It is designed to provide direction to applicants, and it is expected that applicants will file applications consistent with the filing requirements. If circumstances warrant, the Board may require an applicant to file evidence in addition to what is identified in the filing requirements.

The filing requirements apply only to electricity distributors. Unless specifically identified, the words "utility", "utilities", "applicant" or "applicants" in this document refer to electricity distributors.

Transmitters should consult the January 2, 2014 edition of the filing requirements for transmitters for guidance on rate applications.

References to a "party" or "parties" may, depending on the context, refer to the applicant, Board staff and any registered intervenors either individually or collectively.

Renewed Regulatory Framework for Electricity

On October 18, 2012, the Board released its *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") which introduced three rate-setting methods: (1) 4th Generation Incentive Rate-setting ("IR"), (2) Custom IR and (3) Annual IR Index.

Chapters Included in this Filing Requirement Document

This Filing Requirements document sets out the information that must be included in a rate application.

Chapter 1 outlines generic procedural matters and certain expectations of the Board from parties participating in the adjudication process pursuant to Chapters 2, 3 and 5.

Chapter 2 details the filing requirements for a cost of service rate application based on a forward test year that the Board will require from an electricity distribution company.

Chapter 3 details the filing requirements under the incentive regulation mechanism. This approach will be used for electricity distributors when there is no requirement to file a cost of service rate application. Chapter 3 includes specific guidance on requirements related to both the 4th Generation IR (now called "Price Cap IR") and Annual IR Index approaches.

Chapter 5, which was issued by the Board on March 28, 2013, "*Consolidated Distribution System Plan Filing Requirements,*" sets out filing requirements for consolidated distribution system plans. These filing requirements outline the information required by the Board to assess a distributor's planned expenditures on distribution system and other infrastructure. Distributors must review this Chapter and its cover letter, regardless of which rate-setting option they are contemplating, to ensure that they are meeting the specific requirements of this Chapter, which are applicable to all rate-setting methods listed above.

Completeness and Accuracy of an Application

An application to the Board must provide sufficient detail to enable the Board to make a determination as to whether the proposals are reasonable. The onus is on the applicant to substantiate the need for and reasonableness of the costs that are the basis of proposed new rates. A clearly written application that demonstrates the need for the proposed rates, complete with sufficient justification for those rates, is essential to facilitate an effective regulatory review and a timely decision. The filing requirements provide the <u>minimum</u> information that applicants must file for a complete application. However, applicants should provide any additional information that is necessary to justify the approvals being sought in the application.

The Board's examination of an application and its subsequent decision are based only on the evidence filed in that case. This regulatory process ensures that all interested parties to the proceeding have an opportunity to see the entire record, participate meaningfully in the proceeding and understand the reasons for a decision. Consequently, a complete and accurate evidentiary record is essential.

The purpose of the interrogatory process is to test the evidence before the Board, and not to seek information that should have been provided in the original application. The Board will consider an application complete if it meets <u>all</u> of the <u>applicable</u> filing requirements.

Applications must be accurate and information and data presented must be consistent across all exhibits, appendices and models. If an application does not meet <u>all</u> of these requirements, or if there are inconsistencies identified in the information or data presented, the Board may put the application in abeyance unless satisfactory justification for missing or inconsistent information has been provided, or until revised evidence is filed.

Certification of Evidence

Applications filed with the Board must be certified by a senior officer of the applicant that the evidence filed is accurate, consistent and complete to the best of his/her knowledge.

Updating an Application

When material changes or updates to a filing are necessary, a thorough explanation of the changes must be provided, along with revisions to the affected evidence and related schedules. This process is contemplated in Rule 11.02 of the *Rules of Practice and Procedure*. When these changes or updates are contemplated in later stages of a proceeding, applicants should proceed with the update only if there is a material change to the evidence already before the Board. Rule 11.03 states that any such updates should clearly indicate the date of the revision and the part(s) revised.

Interrogatories

The Board is aware of the number of interrogatories that the regulatory review process can generate. The Board advises applicants to consider the clarity, completeness and accuracy of their evidence in order to reduce the need for interrogatories. The Board also advises parties to carefully consider the relevance and materiality of information before requesting it through interrogatories.

It is the Board's expectation that parties will not engage in detailed exploration of items that do not appear to be material. For rate applications, parties should be guided by the materiality thresholds documented in Chapters 2 and 3 in assessing what is material. The Board will consider at the cost award stage of the process whether or not specific intervenors have engaged in excessively detailed exploration of non-material issues and may reflect this in the cost award decision.

Applicants must consult Rules 26 and 27 of the Board's *Rules of Practice and Procedure,* April 24, 2014 revision, for additional information on the filing of interrogatories and matters related to such filings.

Confidential Information

The Board relies on full and complete disclosure of all relevant material in order to ensure that its decisions are well-informed. The Board's expectation is that applicants will make every effort to file material contained in an application publicly and completely without redactions in order to ensure the transparency of the review process. The Board's *Rules of Practice and Procedure* (the "Rules") and the *Practice Direction on Confidential Filings* (the "Practice Direction") do allow for applicants and other parties to request that certain information be treated as confidential. In such cases, the relevant Rules and procedures are to be followed by all participants in a proceeding before the Board. Applicants considering the need for confidential filing of material are expected to review and follow the Practice Direction.

The Board and parties to a proceeding are required to devote additional resources to the administration, management and adjudication of confidentiality requests and confidential filings. Parties must ensure that filings for which they intend to request confidential treatment are clearly relevant to any matter at issue in the proceeding, whether the information is being filed as part of an application, as an exhibit, in response to an interrogatory or as an undertaking. An illustrative list of the types of information that the Board has previously assessed or maintained as confidential is set out in Appendix B of the Practice Direction.

Parties should also take note of the requirements related to relevance of interrogatories outlined in this chapter, which are also applicable to information which is requested and raises confidentiality concerns. Parties should give particular attention to the relevance of any information requested by interrogatories in relation to confidential filings given the administrative issues associated with the management of those filings.

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

Ontario Energy Board

Filing Requirements For Electricity Distribution Rate Applications - 2014 Edition for 2015 Rates Applications -

Chapter 2

Cost of Service

July 18, 2014

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

2.0 Introduction

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

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

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

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

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

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

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

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

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

The filing requirements contained in this Chapter (and Chapter 5) outline all the relevant information necessary for a complete cost of service-based application. The various appendices referenced in this chapter are linked to each of the sections in Chapter 2 and provide schedules to be completed by the applicant to facilitate the filing of all required information (e.g., Appendix 2-P Cost Allocation provides tables related to section 2.10.3 Revenue-to-Cost Ratios). These appendices are available in Microsoft Excel format on the Board's web site and must be completed by applicants and filed as part of a CoS application, including in live Microsoft Excel format.

The models issued by the Board, including those contained in the appendices to this chapter, are provided to assist the applicant in filing a rate application, and to provide consistent formatting for all distributors for greater efficiency of the review process. An application to the Board is the applicant's responsibility and the Board expects that the application will be complete and accurate. Likewise, the applicant bears the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses in supporting its application. The applicant is responsible for advising the Board 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 a Board model does not necessarily mean that the Board will approve the results.

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

2.1 Cost of Service Application in Advance of Scheduled Application

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

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

2.2 Seeking Approval to Align Rate Year with Fiscal Year

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

2.3 General Requirements

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

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

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

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

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

The items outlined below are general requirements that are applicable throughout the application:

- Written direct evidence is to be included before data schedules;
- Average of the opening and closing fiscal year balances must be used for items in rate base;
- Total Capitalization (debt and equity) must equate to Total Rate Base;
- Data for the following years, at a minimum, must be provided:
    - Test Year = Prospective Rate Year;
    - Bridge Year = Current Year;
    - Three Most Recent Historical Years (or for as many years as are necessary to provide actuals back to and including the most recent Board-Approved Test Year, but not less than three years); and
    - Most recent Board-Approved Test Year.
- Documents are to be provided in bookmarked and in text-searchable Adobe PDF format.

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

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

2.3.1 Integrated Distribution Planning

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

Chapter 5 implements the Board's policy direction on an integrated approach to distribution network planning, as set out in the RRFE Report, and applies to distributors filing cost of service applications for the rebasing of their rates under the Price Cap IR or a Custom IR application.

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

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

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

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

For distributor applications going forward, the Board's "*Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence*" will no longer be applicable, and such investments will henceforth be reviewed by the Board in the same fashion as other proposed capital expenditures. The funding mechanisms set out in the "*Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence*" specifically for renewable generation connection and smart grid development will not be available for expenditures proposed in cost of service applications to which Chapter 5 applies as noted above.

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

Distributors yet to file a cost of service application containing a consolidated distribution system plan pursuant to Chapter 5 will continue to be able to record renewable energy generation costs, smart grid demonstration costs and funding adder revenues (for existing funding adders) in deferral accounts already established for this purpose.

These distributors may also seek new funding adders for material eligible investments if they are on the Price Cap IR plan as part of their IRM applications, until such time as the first cost of service application containing a consolidated distribution system plan.

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

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

Further information on the requirements to implement recovery from all Ontario ratepayers can be found in section 2.5.2.5.

2.3.2 Accounting Standards

This section provides information on International Financial Reporting Standards ("IFRS") and Canadian Generally Accepted Accounting Principles ("CGAAP") accounting standards relevant to the filing of 2015 cost of service applications.

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

2.3.2.1 Modified IFRS Application

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

- *Report of the Board: Transition to IFRS*; dated July 28, 2009;
- *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment* (the "Addendum"), dated June 13, 2011;
- *Asset Depreciation Study for the Ontario Energy Board*, Kinectrics Inc. ("Kinetrics Report") for distributors sponsored by the Board dated July 8, 2010;

- Regulatory Accounting Policy Direction Regarding Changes to Depreciation Expense and Capitalization Policies in 2012 and 2013, dated July 17, 2012; and
- Accounting Policy Changes for Accounts 1575 and 1576, dated June 25, 2013.

In February 2013, the Accounting Standards Board decided to extend the deferral of the mandatory adoption of IFRS for Canadian utilities with qualifying rate-regulated activities for financial reporting purposes to January 1, 2015. January 1, 2015 is the mandatory year of adoption for IFRS, therefore, all applicants are expected to file for the test year on the basis of modified IFRS ("MIFRS"), whether they have already adopted IFRS for financial reporting purposes or will adopt IFRS for financial reporting purposes effective January 1, 2015. For most distributors filing for 2015 rates, 2015 will be the year of adoption. CGAAP applications are not expected to be filed.

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

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

Changes to Depreciation and Capitalization Policies:

Per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP in 2012 were required to implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes were mandatory in 2013 for all distributors that had not yet made these changes, and therefore, all applications for 2015 rates should reflect that these changes were made in 2012 or 2013. In the year that the accounting policy changes were implemented, two sets of the applicable information must be presented to show the accounting policy changes. Each set of information must include the PP&E and depreciation schedules.

2.3.3 Performance Evaluation

Under the Renewed Regulatory Framework a distributor is expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services. To facilitate performance monitoring and benchmarking of distributors the Board will use a Scorecard approach.

On March 5, 2014, the Board issued its EB-2010-0379 *Report of the Board on Performance Measures for Electricity Distributors: A Scorecard Approach* which sets out the Board's policies on the measures that will be used by the Board to assess a distributor's effectiveness and continuous improvement in achieving the four outcomes of customer focus, operational effectiveness, public policy responsiveness and financial performance to the benefit of existing and future customers. The form and implementation of the Board's performance monitoring tool – the Scorecard – is also addressed in the Report.

The completed Scorecard presents the five most recent years of available data for each measure. It is designed to track and show an individual distributor's performance gains over a period of time and at a point in time. The distributor's completed Scorecard will be published and made available in the public domain. Therefore, it has been designed to be relevant and meaningful to customers and other stakeholders.

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

In its application, a distributor should discuss its performance for each of the Board's performance outcomes over the last five years, its performance at the current point in time, and its projections for continuous improvements over the term of the application. The application should discuss how the distributor's self-assessment has informed its business plan and the application and describe what measures are planned to achieve further continuous improvement, including any short-, medium-, and long-term performance targets that are being set by the distributor for itself.

2.3.4 Corporate Governance

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

The Board has initiated a policy consultation on corporate governance. This policy consultation will provide the Board with a greater understanding of corporate governance structures and practices that are currently in place for electricity distributors. In particular, consultations with stakeholders, along with research, will focus on the following:

- organizational structure; and
- corporate governance practices.

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

The specific information required by the Board is discussed in section 2.4.8.

2.4 Exhibit 1: Administrative Documents

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

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

2.4.1 Management Discussion and Analysis

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

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

2.4.2 Executive Summary

In addition to providing its overall business strategy, including a narrative of how its approach supports the four outcomes established by the Board in the RRFE report, the applicant has an opportunity in this section to identify key elements of its application. As a minimum, a brief summary of the following items must be provided, if applicable.

A. Revenue Requirement

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

B. Budgeting and Accounting Assumptions

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

C. Load Forecast Summary

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

D. Rate Base and Capital Plan

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

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

E. Operations, Maintenance and Administration Expense

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

F. Cost of Capital

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

G. Cost Allocation and Rate Design

- Summary of any deviations from the Board's cost allocation and rate design methodologies; and
- Summary of any significant changes proposed to revenue-to-cost ratios and fixed/variable splits; and
- 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 RPP and non-RPP customers;
- Disposition period; and
- New Deferral and Variance Accounts requested.

I. Bill Impacts

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

2.4.3 Customer Engagement

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

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

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

If distributors have not undertaken customer engagement activities, distributors must explain why and if any such activities are planned in the future.

Distributors should complete Appendix 2-AC Customer Engagement Activities Summary.

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

2.4.4 Financial Information

This section must include the following:

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

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

- Annual Report and Management's Discussion and Analysis for the most recent year of the parent company, if applicable;

- Rating Agency Report(s), if available;

- Prospectuses, information circulars, etc. for recent and planned public debt or equity offerings.

- Changes in tax status (e.g. a change from a corporation to a limited partnership) must be disclosed;

- Existing accounting orders and list of any departures from the Uniform System of Accounts, including references to accounting orders;

- The accounting standards used for general purpose financial statements and when they were adopted;

- If an applicant is conducting non-utility businesses, such as generation, it must confirm that the accounting treatment it has used has segregated all of these activities from its rate-regulated activities. Distributors owning generation facilities should consult the Board's *Guidelines: Regulation and Accounting Treatments for Distributor-Owned Generation Facilities* G-2009-0300, September 15, 2009.

2.4.5 Materiality Thresholds

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

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

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

Applicants are reminded that the onus is on the applicant to make its case and ensure that the Board has the information it needs to properly assess and deliberate on the application.

2.4.6 Administration

This section must include the following:

- Table of Contents;

- Contact information. The primary contact for the application 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 Board will communicate with this person during the course of the application. After completion of the application, the Board will revert communication to the primary licence contact;

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

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

- Statement as to who will be affected by the application, and which publication(s) the applicant proposes that notice must appear, whether it is a paid publication or not, the readership and circulation numbers, and the rationale for why the stated publication(s) are appropriate;

- Bill impacts (for distributors the distribution only bill impacts as per sub-total A of Appendix 2-W) to be used for the notice of application for a typical residential customer using 800 kWh per month and for a General Service <50kW customer using 2000 kWh per month, or as applicable;

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

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

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

- A statement identifying any changes to the methodologies used in previous applications and a description of the changes;

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

- 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. If there are changes to its Conditions of Service as a result of approval of the application, the distributor must identify all such changes.

2.4.7 Applicant Overview

- Description of applicant's service area:

    - General description and map showing where the utility operates within the province, and the communities serviced by the utility. A utility may provide more detailed geographic and/or engineering maps where these may be useful to understand parts of the application, such as capital expansion or replacement programs;

- A description of whether the distributor is a host distributor (i.e. distributing electricity to another distributor's network at distribution-level voltages) and/or an embedded distributor (i.e. receiving electricity at distribution-level voltages from any host distributor). The distributor must identify the embedded and/or host distributor(s). Partially embedded status must also be clearly identified, including the percentage of load that is supplied through the host distributor(s); and

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

2.4.8 Corporate Governance

The following information must be filed:

- Corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include any planned changes in corporate or operational structure (including any changes in legal organization and control) and rationale for organizational change and the estimated cost impact, including the following;

- o Corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company board; and
- o The reporting relationships between utility management and parent company officials.

- Information about the distributor's corporate governance practices:

1. Board of Directors
   a. The number of board members and how many are independent. State whether or not there is a policy on the number or proportion of independent directors; and
   b. A description of what the board of directors does to facilitate its exercise of independent judgment in carrying out its responsibilities.

2. Board Mandate
   The text of the board's written mandate. If the board does not have a written mandate, describe how the board delineates its role and responsibilities.

3. Board Meetings
   A schedule of the meetings of the Board in the current fiscal year (2014 for 2015 CoS filers).

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

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

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

7. Board Committees
   Identification of any committees of the Board;
   a. For each committee identified:
      (i) a description of the functions of the committee; and
      (ii) the text of the charter for the committee, if one exists.
   b. If there is an audit committee, a statement as to whether or not the members of the committee are (i) independent; and (ii) financially literate.

2.4.9 Letters of Comment

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

2.5 Exhibit 2: Rate Base

This exhibit includes information on:

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

2.5.1 Rate Base

This exhibit must include the following sections:

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

2.5.1.1 Overview

The applicant must provide a complete appendix 2-BA.

For rate base, the applicant must include the opening and closing balances, and the average of the opening and closing balances for gross assets and accumulated depreciation. Alternatively, if an applicant uses a similar method, such as calculating the average in service based on the average of monthly values, it must document the methodology used. Rate base shall also include an allowance for working capital.

At a minimum, the filed material in support of the requested rate base must include data for the Historical Actuals, Bridge 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. Variance analyses must provide a written explanation for rate base-related material when there is a variance greater than the applicable materiality threshold.

If continuity statements have been re-stated for the purposes of the application, 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 Board-approved vs. Historical Actual (for most recent historical Board-approved year);
- Historical Actual vs. preceding Historical Actual (for the relevant number of years);
- Historical Actual vs. Bridge; and
- Bridge vs. Test Year.

The opening and closing balances of gross 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, 2014 and December 31, 2015 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 Work in Progress and Asset Retirement Obligations.

A distributor may include in-service balances previously recorded in deferral or variance accounts (such as smart meters or renewable generation/smart grid related accounts) in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition. This may result in opening balances not reconciling to the closing bridge year property, plant and equipment balances. If this is the case, 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 figures. Distributors must provide the same reconciliation for accumulated depreciation.

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

2.5.1.2 Gross Assets – Property Plant and Equipment and Accumulated Depreciation

The applicant must provide the following information:

- Breakdown by function (transmission or high voltage plant, distribution plant, general plant, other plant) for required statements and analyses;
- Detailed breakdown by major plant account for each functionalized plant item. For the test year, each plant item must be accompanied by a description;
- Summary of any incremental capital module adjustment(s), including what was approved and what was spent, if the distributor received approval for an incremental capital module adjustment as part of a previous IRM application;
- Continuity statements must be reconcilable to the calculated depreciation expenses, under Exhibit 4 – Operating Costs, and presented by asset account. Further guidance is included in the appendices and under section 2.7.4 of these filing requirements.

2.5.1.3 Allowance for Working Capital

In a letter dated April 12, 2012, the Board provided an update to electricity distributors and transmitters on the options established in the June 22, 2011 cost of service filing requirements for the calculation of the allowance for working capital for the 2013 rate year. The applicant may take one of two approaches for the calculation of its allowance for working capital: (1) the 13% allowance approach; or (2) the filing of a lead/lag study.

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

- 13% Allowance Approach

  The 13% Allowance Approach is calculated to be 13% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

The commodity price estimate used to calculate the Cost of Power must be determined by the split between RPP and non-RPP customers based on actual data and using the most current RPP (TOU) price. The calculation must reflect the most recent Uniform Transmission Rates approved by the Board (EB-2012-0031), issued on January 9, 2014 for 2014 rates and effective January 1, 2014. The calculation must include the impacts arising from the new Smart Metering Entity charge approved by the Board on March 28, 2013 in its EB-2012-0100/EB-2012-0211 Decision and Order.

- Lead/Lag Study

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

  - The time between the date customers receive service and the date that the customers' payments are available to the distributor (the lag); and
  - 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 generally dollar-weighted. The dollar-weighted net lag (i.e. lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. This amount is included in the applicant's rate base determination.

2.5.1.4 Treatment of Stranded Assets Related to Smart Meter Deployment

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

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

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

On December 15, 2011, the Board issued *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition*. Section 3.7 and Appendix A-1 provide the most current guidance on the treatment for recovery of costs for stranded meters replaced by smart meters.

If not already addressed in a previous Board decision, distributors must file as part of their 2015 application a proposed treatment for the recovery of stranded meters that conforms with the approach taken by the Board as follows:

- The total estimated NBV of the stranded meters as of December 31, 2014, or a revised amount calculated in accordance with the above-noted accounting guidance, must be removed from rate base (see Appendix 2-S). The 2015 revenue requirement must not include either a return on capital (i.e. debt cost and return on equity) or depreciation expense associated with the total estimated stranded meter costs removed from rate base;
- The total estimated NBV of the stranded meters must be recovered through separate rate riders for the applicable customer classes. A distributor must outline the manner in which it intends to allocate recovery of the NBV of the stranded meters to the applicable customer rate classes and the rationale for the selected approach;
- The total estimated stranded meter costs must be tracked in “Sub-account Stranded Meter Costs” of Account 1555; and
- The associated recoveries from the separate rate riders must also be recorded in this sub-account to reduce the balance in the sub-account.

In order to keep the distributor whole, as noted above, separate rate riders for the applicable customer classes must be proposed to recover the amount of the total estimated stranded costs (i.e. the Stranded Meter Rate Rider).

Distributors wishing to propose a different approach to that outlined above must provide a full explanation of the proposed approach and justification for it, including why the described approach would not be applicable to their circumstances.

If the recovery of stranded conventional meters replaced by smart meters has not been reviewed and approved for recovery in a previous application, the distributor must make a proposal for a Stranded Meter Rate Rider to recover the residual amounts. This applies even for distributors that have had smart meter costs reviewed and approved in stand-alone or IRM applications since their previous cost of service application. A completed Appendix 2-S must also be provided.

2.5.2 Capital Expenditures

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

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

2.5.2.1 Planning

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

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

Regional Planning

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

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

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

Planning Horizon

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

Chapter 5 is to be used by distributors in combination with this Chapter 2. Chapter 5 supersedes the Board's *Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence* (EB-2009-0397). However, information on the costs of any eligible investments identified pursuant to Chapter 5 for which a distributor is seeking prudence review and approval is to be provided as set out in section 2.5.2.5 below.

2.5.2.2 Required Information

As part of this exhibit, distributors must file a consolidated DSP in accordance with Chapter 5 for matters pertaining to asset management, renewable energy generation, smart grid and regional planning. The consolidated DSP should be filed as a stand-alone document. Specifically, all elements of the DSP must be contained in one document and filed as part of Exhibit 2.

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

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

- Written explanation of variances, including that of actuals versus the Board-approved amounts for the applicant's last Board-approved cost of service application; and
- For capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds.

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

2.5.2.3 Capitalization Policy

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

Per the Board's letter of July 17, 2012, electricity distributors that elected to remain on CGAAP in 2012 must have implemented regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes were mandatory in 2013 for all distributors that had not made these changes, and therefore, all cost of service applications for 2015 rates should reflect that these changes were made in 2012 or 2013.

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

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

2.5.2.4 Capitalization of Overhead

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

Burden Rates

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

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

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

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

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

2.5.2.6 New Policy Options for the Funding of Capital

On June 20, 2014, the Board initiated a consultation on *New Policy Options for the Funding of Capital Investments* (EB-2014-0219). While the policy consultation is still ongoing, distributors can propose an approach in their applications based on the proposed policy options, for the Board's consideration.

2.5.2.7 Addition of ICM Assets to Rate Base

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

The applicant must also file the account balances recorded under:

- Account 1508 Other Regulatory Asset, Sub-account, Incremental Capital Expenditures;
- Account 1508 Other Regulatory Asset, Sub-account, Depreciation Expense;
- Account 1508 Other Regulatory Asset, Sub-account, Accumulated Depreciation; and
- Account 1508, Other Regulatory Asset, Sub-account, Incremental Capital Expenditures Rate Rider.

If the Board approves the true-up of any variances, the recalculated revenue requirement relating to the Board-approved ICM capital expenditures should be compared to the rate rider revenues collected in the same period and these variances will be refunded to, or collected from, customers through a rate rider.

2.5.2.8 Service Quality and Reliability Performance

The following information must be provided:

- Reported Electricity Service Quality Requirements ("ESQRs"), as set out in Chapter 7 of the *Distribution System Code*, for the last five completed years. In the event performance is below the established standard, the applicant must provide an explanation for the under-performance, as well as actions taken to address this matter, and any outcomes, as appropriate; and
- SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index), for the last five completed years. Reliability performance for SAIDI and SAIFI must be reported for the two indicators for: (1) All interruptions, and (2) All interruptions excluding Loss of Supply (Cause Code 2). In the event performance is outside of the established range, the applicant must provide an explanation for the under-performance, actions taken to address the issue, and any outcomes (if available).

A completed Appendix 2-G must be filed. Service Quality Indicators are now also required to be provided in this appendix.

2.6 Exhibit 3: Operating Revenue

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

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

The information presented must include:

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

2.6.1 Load and Revenue Forecasts

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

The applicant must also provide an explanation of the weather normalization methodology used. The Board recognizes that an important aspect of any case is the uniqueness of the distributor and the circumstances in which it operates. Generic load profiles and universal normalization methods may not reflect the unique customer mix, weather, and economies of each utility's service territory.

The applicant must include in the test year forecast any impacts arising from the persistence of historical conservation and demand management ("CDM") programs, as well as the forecast impacts arising from new programs in the bridge and test years either through the current 4-year framework or the new 6-year framework. This CDM component of the forecast must be specifically identified by class, as the amount approved by the Board will be the basis for the lost revenue adjustment mechanism variance account ("LRAMVA").

Two types of load forecasting models have generally been filed with the Board in previous cost of service applications. These are Multivariate Regression and Normalized Average Use per Customer ("NAC") models. While the applicant is not restricted to using these approaches, the following information is required for these two modelling methodologies, when used.

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

2.6.1.1 Multivariate Regression Model

- Rationale as to why the proposed model was chosen;
- Statistics of the regression equation(s) (coefficient estimates and associated t-statistics, and model statistics such as R^2, adjusted R^2, F-statistic, or Root-Mean-Squared-Error, etc.). Explanation for any resulting unintuitive relationships (e.g. negative correlation between load growth and economic growth, load growth and customer growth, etc.). A discussion of modelling approaches and alternative models tested must be provided;
- Explanation of the weather normalization methodology proposed including:
  - If the monthly Heating Degree Days ("HDD") and/or Cooling Degree Days ("CDD") are used to determine normal weather, the monthly HDD and CDD based on a) 10-year average and b) a trend based on 20-years;
  - Definition of HDD and CDD:
    - Climatological measurement point (i.e. identification of Environment Canada weather station(s)) and why that is (those are) appropriate for the distributor's service territory; and
    - Identification of base numbers from which HDDs and CDDs are measured (e.g. 18° C).
  - In addition to the proposed test year load forecast, the load forecasts based on a) 10-year average and b) 20-year trends in HDD and CDD; and
  - Rationale as to why the proposed normal weather methodology was chosen.
- Sources of data used for both the endogenous and exogenous variables. Where a variable has been constructed, a complete explanation of the variable, data used and source of the data must be provided. Where a utility has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. billing data not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation as to why the constructed demand series is suitable for modelling;
- Explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.); and

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

2.6.1.2 Normalized Average Use per Customer ("NAC") Model

- Rationale as to why the proposed NAC methodology was chosen;
- Data supporting the calculation of NAC values used in the application for each rate class;
- Description of how CDM impacts have been accounted for in the historical period, and how CDM impacts, including the CDM targets that are a condition of a distributor's licence, are factored into the test year load forecast; and
- Discussion of weather normalization considerations.

2.6.1.3 CDM Adjustment for the Load Forecast for Distributors

Consistent with the Board's *Guideline EB-2012-0003 - Guidelines for Electricity Distributor Conservation and Demand Management*, it is expected that the distributor will integrate an adjustment into the 2015 load forecast that takes into account CDM impacts. The distributor should ensure that it has fully considered measured impacts persisting from prior years, and the expected impacts from new programs on the 2015 load forecast.

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

Further, the actual results for 2011-2013 historical years, which are likely to be used to develop the base forecast, include the impacts of 2011 to 2013 CDM programs. The CDM adjustment to the load forecast should also take into account the historical CDM results factored into the base load forecast before the CDM adjustment, in order to avoid double counting the impacts.

The distributor should document the CDM savings to be used as the basis for the 2015 LRAMVA balance and the corresponding adjustment to the 2015 load forecast. In addition, the allocation of the CDM savings for the LRAMVA and the load forecast adjustment should be provided by customer class and for both kWh and, as applicable, kW. The distributor should document its proposal adequately. Appendix 2-I is provided as one approach for calculating the aggregate amounts for the LRAMVA and the corresponding CDM adjustment to the load forecast.

Appendix 2-I has been updated for 2015 cost of service applications to take into account the 2011-2013 CDM impacts as reported by the OPA, and the forecasted 2014

CDM program impacts assuming that the distributor achieves 100% of its 2011-2014 CDM licence condition target.

On March 31, 2014, the Minister of Energy issued a directive to the Board and a letter of direction to the OPA regarding new CDM targets for the period January 1, 2015 to December 31, 2020. These targets are structured to achieve 7 TWh of energy reductions province-wide over this six-year period, consistent with the 2013 Long-term Energy Plan. As of the issuance date of these Filing Requirements, the OPA has not allocated the 7 TWh reductions to all Ontario distributors. The distributor should include a proposal, with the appropriate rationale, for the level of CDM reductions reflected in the 2015 load forecast.

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

All distributors will be required to make CDM programs available to customers in their licensed service areas between January 1, 2015 and December 31, 2020. Therefore, an assumption of no incremental CDM savings in 2015 will generally not be appropriate and will need to be supported with detailed rationale.

2.6.2 Accuracy of Load Forecast and Variance Analyses

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

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

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

- Customer count increases or decreases forecasted for the Test Year with explanations of the forecast by rate class and identification as to whether customer count is shown in year-end or year average format;

- Explanations for changes in the definition of, or major changes in the composition of, each class, such as the loss, gain or re-classification of major customers in one or more customer classes;
- Weather-normalized (if applicable) average historical actual consumption per customer for historical 5 years and forecasted average consumption for the Bridge Year and Test Year;
- For each rate class, an explanation of the net change in average consumption from last Board Approved and actual for Historical, Bridge Year and Test Year;
- Details for the development of the billing kW value for applicable classes; and
- Revenues, provided on the basis of both existing and proposed rates.

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

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

All data used to determine the forecasts must be presented and filed in live Microsoft Excel spreadsheet format, as also discussed under section 2.6.1.1 above.

2.6.3 Other Revenue

The applicant must provide the following information on Other Revenue. The following information on each of the other distribution revenue accounts (see Appendix 2-H for the required format) must be provided;

- Comparison of actual revenues for historical years to forecast revenue for Bridge and Test Years, including explanations for significant variances in year-over-year comparisons;
- Any new proposed specific service charges, changes to rates or new rules for applying existing specific service charges; and
- Any revenue from affiliate transactions, shared services or corporate cost allocations as described in section 2.7.3.2. For each affiliate transaction, identification of the service, the nature of the service provided to affiliated entities, accounts used to record the revenue and the associated costs to provide the service.

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

2.7 Exhibit 4: Operating Expenses

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

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

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

This exhibit must include the following sections:

1) Overview;
2) Summary and Cost Driver Tables;
3) Program Delivery Costs with Variance Analysis;
4) Depreciation/Amortization/Depletion;
5) Taxes; and
6) CDM.

2.7.1 Overview

The overview should provide a brief explanation (quantitative and qualitative) of the following:

- OM&A Test Year Levels;
- Associated cost drivers and significant changes that have occurred relative to historical and bridge years;
- Overall trends in costs;
- Inflation Rate assumed: The Board will determine an appropriate inflation rate for use by utilities with respect to IRM rate applications, and distributors should be mindful of this rate, and if adopting an inflation rate other than the rate determined by the Board should provide a full explanation as to why this has been done; and
- Business environment changes.

2.7.2 Summary and Cost Driver Tables

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

- Summary of Recoverable OM&A Expenses (Appendix 2-JA);
- OM&A Cost Drivers (Appendix 2-JB);
- OM&A Programs Table and Variance Analysis (Appendix 2-JC); and
- Recoverable OM&A Cost per Customer and per Full Time Equivalent (Appendix 2-L).

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

2.7.3 Program Delivery Costs with Variance Analysis

As identified previously, applicants must complete the revised Appendix 2-JC OM&A Programs Table, making best efforts to identify OM&A costs by program, and, if not, by major functions. This will include a variance analysis between the Test Year costs and the last Board-approved costs and the most recent actuals.

This variance analysis should be limited to variances that are outliers based on the historical trend and should include an explanation on 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:

1) Employee Compensation;
2) Shared Services and Corporate Cost Allocation;
3) Purchases of Non-Affiliate Services;
4) One-time Costs;
5) Regulatory Costs;
6) Low Income Energy Assistance Programs; and
7) Charitable and Political Donations.

2.7.3.1 Employee Compensation Breakdown

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

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

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

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

- Year-over-year variances, inflation rates used for forecasts, plans for any new employee additions and relevant details on collective agreements (e.g., the date the agreement was signed, the effective date, length of term and any information available to the applicant on other collective agreements entered into in the same time period);
- Basis for performance pay, eligible employee groups, goals, measures, and review processes for any pay-for-performance plans; and
- Any relevant studies conducted by or for the applicant (e.g., compensation benchmarking).

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

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

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

2.7.3.2 Shared Services and Corporate Cost Allocation

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

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

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

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

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

The applicant must complete Appendix 2-N in relation to each service provided or received for Historical (actuals), Bridge and Test years. The table found in Appendix 2-N must be completed for each year. Additional rows may be added if required. Applicants must provide a reconciliation of the revenue arising from Appendix 2-N with the amounts included in Other Revenue in section 2.6.3.

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

- Test Year vs. Last Board-approved; and
- Test Year vs. Most Recent Actuals.

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

2.7.3.3 Purchases of Non-Affiliate Services

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

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

- Summary of the nature of the product or service that is the subject of the transaction; and
- A description of the specific methodology used in determining the vendor (including a summary of the tendering process/cost approach, etc.).

2.7.3.4 One-time Costs

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

2.7.3.5 Regulatory Costs

The applicant must provide a breakdown of the actual and anticipated regulatory costs, including OEB cost assessments and expenses for the current application such as legal fees, consultant fees, costs awards, etc. Appendix 2-M must be completed. The applicant must provide information supporting the level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify how such costs are to be recovered (i.e., over what period the costs are proposed to be recovered). For distributors, the recovery period would normally be the duration of the expected cost of service plus IRM term under the Price Cap IR option. If the applicant is proposing a different recovery period, it must explain why it believes this is appropriate.

2.7.3.6 Low-income Energy Assistance Programs ("LEAP")

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

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

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

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

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

2.7.3.7 Charitable and Political Donations

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

The applicant must file the amounts paid in charitable donations (per year) from the last Board-approved rebasing application up to and including the test year. The recovery of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to the distributor's customers in paying their electricity bills and assistance to low income consumers (e.g. applicable programs under 2.7.3.6 above). If the applicant wishes to recover such contributions, it must provide detailed information for such claims.

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

2.7.4 Depreciation, Amortization and Depletion

Applicants must demonstrate that the proposed levels of depreciation/amortization expense are appropriately reflective of the useful lives of the assets and the Board`s accounting policies.

The Kinectrics Report[2] provides information that the Board expects distributors will consider as they develop asset service lives to be included in their cost of service applications. However, while the Kinectrics Report contains a range of useful lives for assets, distributors must ensure that these ranges (and the specific useful lives selected within the ranges) are appropriate to their circumstances when preparing an application and must provide explanations for any useful lives that are proposed in the application that are not within the ranges contained in the Kinectrics Report.

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

- The applicant must provide details for Depreciation, Amortization and Depletion by asset group for the Historical, Bridge and Test Years, including asset amounts and rates of depreciation or amortization. This must tie back to the accumulated depreciation balances in the fixed asset continuity schedule (Appendix 2-BA) under Rate Base.
- The applicant must identify any Asset Retirement Obligations ("AROs") and any associated depreciation or accretion expenses in relation to the AROs, including the basis for and calculation of these amounts.
- The Board's general policy for electricity distribution rate setting has been that capital additions would normally attract six months of depreciation expense when

[2] Issued July 8, 2010

they enter service in the test year. This is commonly referred to as the "half-year" rule. On June 20, 2014, the Board initiated a consultation *New Policy Options for the Funding of Capital Investments* (EB-2014-0219). While the policy consultation is still ongoing, distributors can propose an approach in their applications based on the proposed policy options for the Board's consideration.

- The applicant must also identify its historical practice and its proposal for the test year. Variances from the half-year rule, such as calculating depreciation based on the month that an asset enters service, must be documented with explanation.
- The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant must provide a written description of the depreciation practices followed and used in preparing the application. The applicant must provide a summary of changes to its depreciation/amortization policy made since the applicant's last cost of service filing.
- The applicant must ensure that the significant parts or components of each item of PP&E are being depreciated separately, in accordance with its adopted accounting standard. The applicant must explain any deviations from this practice.

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

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

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

Applicants should make use of the stand-alone principle when determining these amounts[3]. Applicants are expected to exercise sound tax planning and are expected for rate-setting purposes to maximize tax credits and take the maximum deductions allowed.

The applicant must provide the information outlined below:

- Detailed calculations of Income Tax or PILs, as applicable (including a completed pdf and live Microsoft Excel version of the Income Tax /PILs model available on the Board's web site), including derivation of adjustments (e.g., Tax credits, CCA adjustments) for the Historical, Bridge and Test Years. Regulatory assets (and regulatory liabilities) must generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts;
- Supporting schedules and calculations identifying reconciling items;
- Copies of most recent Federal and Provincial tax returns (non-utility tax items, if material, must be separated);
- Financial statements included with tax returns, if different from the financial statements filed in support of the application (section 2.4.3);
- A calculation of tax credits (e.g., Apprenticeship Training Tax Credits, education tax credits). A Scientific Research and Experimental Development ("SRED") return, if filed, may have confidential personal information of the people who are apprenticing like SIN, address, hourly rate, etc. All such personal confidential information must be excluded or redacted from the filing; and
- Supporting schedules, calculations and explanations for "other additions" and "other deductions" in the applicant's PILs model.

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

2.7.5.1 Non-recoverable and Disallowed Expenses

There may be some distribution-only expenses incurred by a distributor that are deductible for general tax purposes, but for which recovery in 2015 distribution rates is partially or fully disallowed.

[3] Please see Introduction, page 2 of this document.

Where an expense incurred by a distributor is non-recoverable in the revenue requirement (e.g. certain charitable donations as discussed in 2.7.3.7 above) or disallowed for regulatory purposes, such costs should also be excluded from the regulatory tax calculation.

2.7.5.2 Integrity Checks

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

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

2.7.6 Conservation and Demand Management

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

2.7.6.1 Lost Revenue Adjustment Mechanism

The lost revenue adjustment mechanism ("LRAM") is a retrospective adjustment, which is designed to account for differences between the forecast revenue loss embedded in rates and the actual revenue loss.

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

2.7.6.2 LRAM for pre-2011 CDM activities

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

2.7.6.3 LRAM Variance Account (LRAMVA)

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

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

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

Disposition of the LRAMVA

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

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

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

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

2.8 Exhibit 5: Cost of Capital and Capital Structure

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

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

2.8.1 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 Board Approved and Test year. Appendix 2-OB must be completed for all required historical years, the bridge year and the Test year.

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

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

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

2.8.2 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 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 is affiliated or with a third party, expected term/maturity, any capital project(s) that the debt funding is for, etc.); and
- If the applicant is proposing any rate that is different from the Board guidelines, a justification of forecast costs by item, including key assumptions.

2.8.3 Not-for-Profit Corporations

In prior Board Decisions and Orders,[4] the Board has determined that applicants that are not-for-profit corporations shall retain the excess revenue in excess of its costs only for the purpose of meeting the applicant's need to build up appropriate operating and capital reserves based on applicant's forecast in the test year ("Reserve Requirement"). The Board has further stated that, once the appropriate limits for these reserves have been achieved, it would expect such applicants to submit an application seeking a rate adjustment to discontinue the buildup.

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

- The applicant shall provide the detailed calculation for its test year revenue requirement based on its Reserve Requirement. The applicant's revenue requirement shall equal to the sum of all costs plus the annual incremental amounts needed for building up the proposed reserves;
- The proposed reserves (operating, capital, insurance, etc.), the rationale for the need to establish each reserve, the time period of building up the reserves, and the procedure and policy of each reserve. The policy and procedure of each reserve should include the following information:
    i. The definition of each reserve;
    ii. The purpose, goals and intended use of each reserve;
    iii. The capped amounts of each reserve and the methodology used to derive such amounts;
    iv. The mechanism and the process to build, use and maintain the reserves;

[4] Attawapiskat Power Corporation 2006 CoS Decision and Order EB-2005-0233; Five Nations Energy Inc. 2010 CoS Decision and Order EB-2009-0387

- A description of the applicant's governance of the not-for-profit corporation, including the following:
    i. Policy on Reserve Requirement
    ii. The roles and responsibilities of the applicant's Board of Directors and management with regards to the need for types of reserve funds and establishing and preserving the amounts for each types of reserves;
    iii. The authorization and approval process for access and use of the reserves;
    iv. Investment objectives and policies for the reserve funds; and
    v. Reporting requirements and monitoring.

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

2.9 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; and
- Gross Deficiency or Sufficiency in Revenue.

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

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

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

2.9.1 Revenue Requirement Work Form

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

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

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

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

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

2.10 Exhibit 7: Cost Allocation

The following areas are discussed in this exhibit:

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

2.10.1 Cost Allocation Study Requirements

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

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

For any customer class for which updated load profiles are not available, the load profiles provided by Hydro One for use in the Informational Filing may be used, scaled to match the load forecast as it relates to the respective rate classes (see section 2.6.2 above). In particular, if a rate class has experienced a decline in customers or disappeared, or will disappear in the Test Year, the model must be consistent with the updated load forecast, and include an explanation of the changed load forecast of the rate class. Similar treatment would also apply in the case where a new customer class is being created.

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

If using the Board-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 c-15 and c-17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information. A complete hard copy of the cost allocation model is not required, but the distributor must file a complete live Microsoft Excel cost allocation model with the application.

Large General Service and Large Use Classes

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

Embedded Distributor Class

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

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

Unmetered Loads

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

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

The revenue requirement of the Street lighting class has been shown based on experience to be sensitive to inputs related to the number of connections (which determines the number of services) as distinct from the number of street lighting devices (which determines the estimated coincident and non-coincident loads). Distributors are encouraged to use information that is as accurate as possible based on their physical network design, and demand and consumption profile of devices and to stay apprised of progress in modeling of allocation of costs in this area including any further Board policy changes.

microFIT class

The Board does not expect a distributor to include microFIT as a separate class in the cost allocation model in 2015. The model will produce a calculation of unit costs which the Board will use to update the uniform microFIT rate at a future date. Unlike other classes, the cost information is not used to establish a separate class revenue requirement for the microFIT class.

New Customer Class(es)

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

Eliminated Customer Class(es)

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

2.10.2 Class Revenue Requirements

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

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

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

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

2.10.3 Revenue-to-Cost Ratios

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

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

- The previously approved ratios most recently implemented by the distributor;
- The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model; and
- The ratios that are proposed for the test year, which are the proposed class revenues, together with the updated cost allocation model.

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

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

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

2.11 Exhibit 8: Rate Design

The following areas are discussed in this exhibit:

1) Fixed/Variable Proportion;
2) Rate Design Policy Consultation
3) Retail Transmission Service Rates (RTSRs);
4) Retail Service Charges;
5) Wholesale Market Service Rate;
6) Smart Metering Charge;
7) Specific Service Charges;
8) Low Voltage Service Rates (where applicable);
9) Loss Adjustment Factors;
10) Tariff of Rates and Charges;
11) Revenue Reconciliation;
12) Bill Impact Information; and
13) Rate Mitigation (where applicable).

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

2.11.1 Fixed/Variable Proportion

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

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

If a distributor's current fixed charge 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.

The fixed/variable analysis must be net of (i.e. exclude) rate adders, funding adders and rate riders (i.e. Low Voltage, smart meter rate riders, GEA and smart grid rate riders, deferral/variance account disposition, etc.).

2.11.2 Rate Design Policy Consultation

On April 3, 2014, the Board released its *Draft Report on Rate Design for Electricity Distributors (EB-2012-0410)* which proposed implementing a fixed monthly charge for distribution service. While the policy consultation is still ongoing, distributors can propose a fixed monthly charge within their applications based on the proposed policy options as applicable, for the Board's consideration. In proposing a fixed monthly service charge to recover distribution service costs, the distributor must provide an explanation of the method used to design the fixed charge.

2.11.3 Retail Transmission Service Rates ("RTSRs")

In preparing its application, the distributor must reference the Board's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates,* October 22, 2008, and subsequent updates to the Uniform Transmission Rates ("UTRs"). A completed version of the RTSR model must be filed in pdf and live Microsoft Excel.

The distributor must ensure that the information provided in this section is consistent with that provided in the working capital allowance calculation provided in Section 2.5.1.3, as it relates to rates such as RTSRs, or provide explanations for any differences.

2.11.4 Retail Service Charges

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

Distributors must maintain the appropriate Retail Service Costs Variance Accounts ("RCVA") to record the difference between charges rendered to customers and retailers, and the direct incremental costs for the provision of these services. The RCVAs are discussed in section 2.12.6.

2.11.5 Wholesale Market Service Rate

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

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

This rate will be set by the Board on a generic basis. Distributors wishing to apply for a rate other than the generic rate set by the Board must provide justification as to why their specific circumstances would warrant such a different rate.

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. Furthermore, on December 19, 2013, the Board issued a Decision and Rate Order (EB-2013-0396) which approved the rate for rural and remote rate protection ("RRRP") to be $0.0013 per kilowatt hour, effective May 1, 2014. Distributors should reflect a total charge of $0.0057 per kilowatt hour in their applications.

2.11.6 Smart Metering Charge

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

2.11.7 Specific Service Charges

A distributor must describe the purpose of each new or revised specific service charge for which it is seeking approval*.* Distributors must specify which charges are new and for which existing charges they are proposing changes.

Distributors 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 such charge including the following elements:

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

Distributors must also identify any rates and charges that are included in the Conditions of Service but do not appear on the Board-approved tariff sheet, and an explanation for the nature of the costs being recovered must be provided. A schedule outlining the revenues recovered from these rates and charges from 2010 to 2013 and the revenue forecasted for the 2014 bridge and 2015 test years must also be provided as well as an explanation whether these rates and charges must 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 2.6.3).

On June 27, 2014, the Board released a letter initiating a *Policy Review of Electricity and Natural Gas Distributor's Residential Customer Billing Practices and Performance (EB-2014-0219).* While the policy review is still ongoing, distributors may propose activities or initiatives that will reduce the costs of a transition to monthly. For example, this could include a proposal to promote greater use of electronic billing by seeking approval for a credit service charge to be provided to customers who opt for a paperless bill.

2.11.8 Low Voltage Service Rates (where applicable)

If the distributor is (fully or partially) embedded (see section 2.4.7) the distributor must provide the following information:

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

2.11.9 Loss Adjustment Factors

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

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

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

2.11.10 Tariff of Rates and Charges

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

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

2.11.11 Revenue Reconciliation

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

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

The applicant must provide a completed Appendix 2-V.

2.11.12 Bill Impact Information

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

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

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

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

2.11.13 Rate Mitigation

In the RRFE report the Board concluded that it will maintain its current policy on rate mitigation.

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

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

2.11.13.1 Mitigation Plan Approaches

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

- A specification of all customer classes or groups of customers that were initially identified as having increases in excess of 10% and the magnitude of these increases;
- A detailed description of any mitigation measures undertaken, e.g. reductions to the revenue requirement, inter- or intra-class shifts, or longer disposition periods for deferral and variance account balances;
- A justification for all mitigation measures proposed, including reasons if no mitigation is proposed;
- Revised impact calculations in Appendix 2-W reflecting the mitigation plan ; and
- Any other information the distributor believes is relevant to its mitigation proposal.

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

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

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

2.11.13.2 Rate Harmonization Mitigation Issues

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

In the event that the combined impact of the cost of service based rate increases and harmonization effects result in total bill increases for any customer class exceeding 10%, the distributor must include a discussion of proposed measures to mitigate any such increases in its mitigation plan discussed in section 2.11.13 or provide a justification as to why a plan is not required.

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

2.12 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:

- List of all outstanding deferral and variance accounts and sub-accounts. The applicant must provide a brief description of any account that the applicant may have used differently than as described in the APH;
- A continuity schedule for the period following the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances. A completed version of the continuity schedule available on the Board's web site must be filed in live Microsoft Excel format;
- Interest rates applied to calculate the carrying charges for each regulatory deferral and variance account. The applicant must provide the rates by month or by quarter for each year. These rates are provided on the Board's website. The most recent posted interest rate is used for any future periods until updated by the Board;
- Explanation if the account balances in the continuity schedule differ from the account balances in the trial balance reported through the *Electricity Reporting and Record-keeping Requirements* and the Audited Financial Statements;

- Identification of which Group 2 accounts the distributor will continue and which will be discontinued on a going-forward basis, with an explanation for each;
- Statement as to any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account. This must correspond with information provided in Exhibit 1 (see section 2.4.6);
- 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 Board on a final basis in both cost of service and IRM proceedings (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding). If this is the case, the applicant must provide explanations for the nature and amounts of the adjustments and include supporting documentation, under a section titled “Adjustments to Deferral and Variance Accounts.”
- A breakdown of energy sales and cost of power expense balances, as reported in the audited financial statements by distributors, mapped to USoA account number. The distributor must reconcile these numbers to the audited financial statements. If there is a difference between the energy sales and cost of power expense reported numbers, the distributor must explain why it is making a profit or loss on the commodity; and
- A statement confirming that the distributor pro-rates the IESO Global Adjustment Charge into the RPP and non-RPP portions. If this is not the case, the distributor must provide an explanation.

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

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

2.12.2 Harmonized Sales Tax Deferral Account

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

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

No more amounts should be recorded in Account 1592 (PILs and Tax Variances for 2006 and subsequent years, Sub-account HST/OVAT ITCs for the test year and going forward), as the impact of the HST and associated ITCs on capital and operating costs in the test year must be reflected in the applied-for revenue requirement. For the 2015 test year for example, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to December 31, 2014 since the test year, which starts January 1, 2015 would include the HST impacts in rates going forward. If the test year's rate year begins May 1, 2015, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to April 30, 2015.

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

2.12.3 One-time Incremental IFRS Costs

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

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

- File for disposition of the balance in Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance reflecting the difference between the amounts recovered in rates and the actual incurred one-time administrative incremental IFRS transition costs. Any one-time administrative incremental IFRS transition costs already included for recovery in rates must be included as credits on a separate line in Appendix 2-U;
- Provide a statement as to whether any one-time administrative incremental IFRS transition costs are embedded in the proposed 2015 revenue requirement. If this is the case, the applicant must state the section of the proposed 2015 revenue requirement that includes these costs, the quantum and explain why it is included in the 2015 revenue requirement instead of the Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account;
- Provide explanations for each category of costs recorded in the Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account

or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account. The applicant must explain how the costs recorded meet the criteria of one-time IFRS administrative incremental costs;

- Provide explanations for material variances that may be recorded in the Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance account; and
- Per the October 2009 APH FAQ #3 regarding costs that are permitted to be recorded in the Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account and Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account, the applicant must provide a confirmation statement that no capital costs, ongoing IFRS compliance costs, or impacts arising from adopting accounting policy changes are recorded in Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account. If this is not the case, the applicant must provide an explanation.

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

Account 1575 will apply to an applicant that files a 2015 cost of service application on the basis of MIFRS. For an applicant filing based on MIFRS, Account 1575 must capture all PP&E accounting changes made on transition to IFRS, with the exception of those related to capitalization and depreciation that are captured in Account 1576.

Deferral Account 1575 and variance Account 1576 cannot be used interchangeably and the applicant must follow the required accounting treatment applicable under each account. The accounting changes applicable to Account 1576 are not applicable to Account 1575 in relation to “changeover date” accounting on the applicant’s adoption of IFRS. Depending on the date the applicant implemented capitalization and depreciation policy changes and the date the applicant adopts IFRS, applicants are typically expected to have balances in Account 1576 as a result of the Board mandated capitalization and depreciation policy changes under CGAAP as referenced in 2.12.5 below. Applicants may also have balances recorded in Account 1575 for any further PP&E accounting changes made on transition to IFRS.

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

Applicants must provide the following:

- A breakdown of the balance related to the IFRS-CGAAP Transitional PP&E Amount that is effective on the transition date to MIFRS. The applicant must provide the supporting analysis of the amounts in this account by completing Appendix 2-EA;

- A listing and quantification of the drivers of the change in closing net PP&E (CGAAP versus MIFRS). The Fixed Asset Continuity Schedule (Appendix 2-BA) in the rate application must not be adjusted for balances related to the IFRS-CGAAP Transitional PP&E Amount. The applicant must show that the application of the accounting policies change is applied on a prospective basis in the year in which the accounting changes occurred (e.g., 2014);
- A breakdown for quantification of any accounting changes arising from the transition to IFRS in relation to PP&E (e.g. customer contributions, asset retirement obligations, interest capitalization, etc.), including an explanation for each of the accounting changes made by the applicant;
- A separate volumetric rate rider for Account 1575 for the clearance of the account balance over the proposed disposition period, including all calculations showing its derivation. The applicant must show that the rate rider is comprised of the amortized amount of the account balance over the number of years proposed for the disposition period (e.g. five years);
- A rate of return component (i.e., weighted average cost of capital) to be applied to the balance of Account 1575, including all calculations showing its derivation. The rate of return amount must be amortized over the number of years proposed for the disposition period (e.g. five years) and added together with the account balance amortized amount for inclusion in the Account 1575 rate rider. The amount for the return component must not be recorded in Account 1575;
- A statement confirming that no carrying charges are applied to the balance in the account;
- An explanation for the basis of the proposed disposition period to clear the Account 1575 rate rider. The Board's determination of the disposition period will be on a case-by-case basis and will be guided primarily by such considerations as bill impacts and the financial impact on applicants; and
- The balance of the account in the DVA Continuity Schedule.

2.12.5 Account 1576, Accounting Changes Under CGAAP

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

For the typical applicant that files a 2015 test year application under MIFRS and made the changes to capitalization or depreciation policies by January 1, 2013 under CGAAP, the applicant must file with the Board a request to clear Account 1576 for these changes as part of the cost of service application.

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

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

Applicants must provide the following:

- The Fixed Asset Continuity Schedule (Appendix 2-BA) in the rate application, which must not be adjusted for balances related to Account 1576. The applicant must show that the application of the accounting policies change is applied on a prospective basis in the year in which the accounting charges occurred (e.g. 2013);
- A breakdown of the balance related to Account 1576. The applicant must provide the supporting analysis of the amounts in this account by completing Appendices 2-EB or 2-EC. The drivers of the change in closing net PP&E (former policies under CGAAP versus revised policies under CGAAP) must be identified and quantified;
- A separate volumetric rate rider for Account 1576 for the clearance of the account balance over the proposed disposition period, including all calculations showing its derivation. The applicant must show that the rate rider is comprised of the amortized amount of account balance over the number of years proposed for the disposition period (e.g. five years);
- A rate of return component (i.e., weighted average cost of capital) to be applied to the balance of Account 1576, including all calculations showing its derivation. The rate of return amount must be amortized over the number of years proposed for the disposition period (e.g. five years) and added together with the account balance amortized amount for inclusion in the Account 1576 rate rider. The amount for the return component must not be recorded in Account 1576;
- A statement confirming that no carrying charges are applied to the balance in the account;
- An explanation for the basis of the proposed disposition period to clear the account balance through the Account 1576 rate rider. The Board’s determination of the disposition period will be on a case-by-case basis and will be guided primarily by such considerations as bill impacts and the financial impact on distributors; and

- The balance of the account in the DVA Continuity Schedule.

2.12.6 Retail Service Charges

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

- Confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services;
- Identify the drivers for the balances in Account 1518 and/or Account 1548;
- Provide a schedule identifying all revenues and expenses listed by USoA account number, that are incorporated into the variances recorded in Account 1518 and/or Account 1548 for 2013, the actual/forecast for 2014 and a forecast for 2015; and
- State whether or not the distributor has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. The distributor must provide an explanation and quantify the variance if the distributor has not followed Article 490.

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

2.12.7 Disposition of Deferral and Variance Accounts

The applicant must:

- Identify all accounts for which it is seeking disposition;
- Identify any accounts for which the applicant is not proposing disposition and the reasons why;
- Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements and provide explanations for any variances;
- Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's RRR filings for each account;
- Provide explanations, even if such variances are below the 5% threshold, if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior Board decisions, and prior period adjustments); and/or (2) the

cumulative effect of immaterial differences over several accounts total to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings;

- Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period. If a distributor is proposing to allocate a deferral or variance account for which the Board has not established an approved allocator, the distributor must propose an allocator based on the cost driver(s), along with the charge type (fixed or variable) for recovery purposes, and include this in the continuity schedule;
- Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period, an explanation must be provided;
- Establish separate rate riders to recover the balances in the RSVAs from Market Participants ("MPs") who must not be allocated the RSVA account balances related to charges for which the MPs settle directly with the IESO (e.g. wholesale energy, wholesale market services);
- Establish separate rate riders to recover the balance of Account 1589 - Global Adjustment from non-RPP customers. Distributors who serve Class A customers per O.Reg 429/04 (i.e. customers greater than 5 MW) must propose an appropriate allocation for the recovery of the global adjustment variance balance based on their settlement process with the IESO: and
- 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 Board-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements; and
    - Prudence – The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

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

2.12.8 LRAM Variance Account (LRAMVA)

Material included in this section in the 2014 version of Chapter 2 has been moved to section 2.7.6.3

2.12.8.1 Disposition of the LRAMVA

Material included in this section in the 2014 version of Chapter 2 has been moved to section 2.7.6.3.

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

Orientation Session
Electricity Distributors Rebasing for 2015 Rates
New Policy Options

Keith Ritchie – Project Advisor, Electricity Rates and Accounting
July 24, 2014

Overview

- Regional Planning (may include Service Area Amendments)
- Advanced Capital Module
- ½ Year Rule
- Fixed Monthly Charge for Distribution Service
- Incentives to reduce costs for Monthly Billing

Service Area Amendments and MAADs Rate-Making Policy Review (EB-2014-0138)

- March 31, 2014 – staff discussion paper on a *Review of the Board's Polices and Processes to Facilitate Electricity Distributor Efficiency: Service Area Amendments and Rate-Making Associated with Distributor Consolidation*

- Wording included in FRs to remind LDCs that in looking at their plans for expansion, the distributor has considered municipal boundaries but in a regional context, i.e. how best to serve boundary areas

Planning

- Distributors will be expected to file evidence that demonstrates that regional issues have been appropriately considered and, where applicable, addressed in developing the utility's proposed capital expenditure plan.

- As part of its planning, a distributor should consider municipal planning, including any plans for expansion of municipal boundaries from a regional perspective to demonstrate the most cost effective solutions are being considered. (*FR section 2.5.2.1*)

New Policy Options for the Funding of Capital Investments (EB-2014-0219)

- Initiated June 20, 2014

- Advanced Capital Module and ½ Year Rule
  - Invited group of utilities, EDA, intervenors
  - provided feedback on concepts of ACM and D_1 –factor

- While the policy consultation is still ongoing:
  - distributors can propose an approach in their applications based on the proposed policy options, for the Board's consideration (*FR sections 2.5.2.6 and 2.7.4*)

Summary of Capital Modules

Capital Modules	Cost of Service Application	Price Cap IR Application (for year in which capital project goes into service)	Next Cost of Service
ACM (Advanced Capital Module)	• Identify **discrete** projects in DSP which might qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information • Preliminary calculation of threshold capex (i.e. materiality test)	• Updated threshold capex based on current information to confirm that the project continues to qualify for ACM treatment • Explain significant differences in timing or costs from DSP forecast • Provide incremental revenue requirement calculation and proposed ACM rate riders	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable) • Based on above, the Board may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV
ICM (Incremental Capital Module)	• Not Applicable	• **Opportunity for ICM if demonstrated that the discrete project could not have been foreseen or sufficiently planned as part of DSP** • Establish need for and prudence of these projects • Provide threshold capex, incremental revenue requirement calculation and proposed ICM rate riders (reflecting updated formula and means test)	• Same as above

Summary of the ½ Year Rule Adjustment Factor

The D_1 -factor

- D_1 is the ratio of the incremental revenue requirement to adjust for full year impact:
  - The D_1-factor represents the "other half" of the revenue requirement impact for test year additions
  - depreciation expense, return on capital and associated taxes/PILs expenses beyond the cost of service test year for test year capital additions
- Current price cap IR formula is:

$$P_{t+1} = P_t \times (1 + (IPI - 0 - stretch\_factor \pm Z))$$

- In first price cap IR adjustment following rebasing, price cap formula would be:

$$P_{t+1} = P_t \times (1 + (IPI - 0 - stretch\_factor \pm Z + D_1))$$

- D_1 can be easily calculated based on information available and approved in a cost of service application
  - Applied as a factor in the price cap formula, to increase base rates accordingly
  - It would affect all classes and fixed/variable rates equally
  - Once approved, its application and quantum in the first Price Cap IR application following rebasing should not be controversial
  - No further adjustment in future years
  - Depending on circumstances, D_1 would be an adjustment of likely 3% or less to distribution rates, incremental to annual price cap adjustment in that first Price Cap IR application (Note: Dx base rates are ~ 25% of total bill)
  - D_1 factor only available for 2015 CoS filers onward

Rate Design for Electricity Distributors (EB-2012-0410)

- This initiative builds on extensive work and consultations previously undertaken by the Board.
  - Revenue Decoupling (EB-2010-0060); and
  - Rate Design for the Recovery of Electricity Distribution Costs (EB-2007-0031)

- April 3, 2014 - the Board released its Draft Report
  - proposed implementing a fixed monthly charge for distribution service
  - While the policy consultation is still ongoing:
    - distributors can propose a fixed monthly charge within their applications based on the proposed policy options as applicable, for the Board's consideration.
    - distributor must provide an explanation of the method used to design the fixed charge (*FR section 2.11.2*)

Policy Review of Electricity and Natural Gas Distributor's Residential Customer Billing Practices and Performance (EB-2014-0219)

- Initiated June 27, 2014
- While the policy review is still ongoing:
  - distributors may propose activities or initiatives that will reduce the costs of a transition to monthly billing.
  - E.g. this could include a proposal to promote greater use of electronic billing by seeking approval for a credit service charge to be provided to customers who opt for a paperless bill (*FR section 2.11.7*)

Questions?

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

Orientation Session
Electricity Distributors Rebasing for 2015 Rates

Customer Engagement Activity

Birgit Armstrong, Advisor, Electricity Rates and Prices
July 24, 2014

Overview

- Performance Outcomes
- Filing Requirements
  - Chapter 2/Exhibit 1 – A Summary Overview
  - Appendix 2-AC
  - Chapter 5/DSP – Details and Impacts of Customer Engagement Activities
- Performance Measurement
  - The Scorecard Approach

Performance outcomes

- A Key Outcome established in the RRFE is Customer Focus
- For applications this includes a requirement for customer engagement, both in regards to distribution system plans and for the application in general

Examples of Customer Engagement Activities – 2014 Cost of Service Applications

Outreach Activities Provides feedback to incorporate into the planning process	Communications Increases customer awareness, trust and energy literacy
Own Survey	Awareness Initiatives
Survey by Third Party	Attendance at Community Events
Town Hall Meetings	Re-Designed Website
Focus Groups	Bill Inserts/E-Mail Blasts
Social Media Campaigns	Customer Education Seminars
Direct Communications (In-Person)	Re-Designed Corporate Brand

- To inform plans, a useful tool should include:
  - Clear and specific goals;
  - Description of the considered investment and the value of those proposals to customers (i.e. costs, benefits and rate impacts);

Filing Requirements – Chapter 2

- In Exhibit 1, the Board expects distributors to provide an overview/summary of customer engagement activities, including the following elements:
  - Discuss how customers were engaged, this should include communication and/or outreach activities;
  - Provide the feedback received from customers and show how that has impacted distributors' plans;
  - Complete new Appendix 2-AC Customer Engagement Activities Summary;
  - If a distributor has not included any customer engagement activities, distributors must explain why and what activities are planned for the future.

Filing Requirements – Appendix 2-AC

2015 Addition to Chapter 2 Appendices

File Number:	0
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
	1, 2.	
	1, 2.	
	1, 2.	
	1, 2.	
	1, 2.	

Filing Requirements – Chapter 5

- Coordinated planning with third parties as required in Chapter 5, includes engaging with customers.
- In order to demonstrate that a distributor has met the Board customer engagement expectations, a DSP should provide details of these activities, including:
  - Purpose of the consultation;
  - A value proposition the proposed investment represents for customers;
  - Customer preferences/inputs;
  - Indication of whether the consultations have affected the DSP and if so, how;

Performance Evaluation – The Scorecard

- *Report of the Board on Performance Measures for Electricity Distributors: A Scorecard Approach,* March 5, 2014 (EB-2010-0379).
- Customer Focus is one of four performance outcomes and performance in the following areas will be assessed:

Service Quality	Customer Satisfaction
New Residential Services connected on Time	First Contact Resolution
Scheduled Appointments met on Time	Billing Accuracy
Telephone calls answered on Time	Customer Satisfaction Survey Results

Customer Satisfaction Survey

- The Board expects distributors' surveys will at a minimum, canvass customer satisfaction in the following key areas:

  a. Power Quality and Reliability;
  b. Price;
  c. Billing and Payment;
  d. Communications; and
  e. Customer Service Experience.

- A distributor has full discretion to determine how to conduct their surveys, however distributors are required to report results biannually.

- The Board has not set a defined target for this measure.

Questions

Thank you

Need information?

Industry Relations Inquiry:
Email: IndustryRelations@ontarioenergyboard.ca

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

Orientation Session
Electricity Distributors' Rebasing for 2015 Rates

Consolidated Distribution System Plan

Keys to Success and Avoidance of Common Pitfalls

David Richmond, Manager, Facilities & Infrastructure
Nabih Mikhail, Project Advisor, Facilities & Infrastructure
July 24, 2014

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Chapter 5 & Chapter 2: capital expenditure focus

- Chapter 5 consolidates a distributor's information
  - on system planning, focussing on the asset management and capital expenditure planning processes used to identify, select, prioritize and schedule all types of investment; and
  - on the resulting integrated 5 year plan, detailing the investments for which costs are proposed for recovery
- Chapter 2 focusses on a distributor's information
  - on the impact of their proposed capital expenditures as explained in Chapter 5 on test year rate base and the revenue requirement

this presentation:

- Assumes Familiarity with Chapter 5, Filing Requirements – Consolidated Distribution System Plan, March 28, 2013.
- A two-part Integrated Planning presentation can be found on the Board's 2014 EDR webpage from last year's Orientation Session:
  - Part 1: Regional Infrastructure Planning
  - Part 2: Chapter 5, Consolidated Distribution Plan Filing Requirements
- Highlights keys to success, and avoidance of common pitfalls – Lessons learned from 7 DSP Plans included in the 2014 CoS Applications

Renewed Regulatory Framework: expectations for and evaluation of distributor plans

- the Board expects that a distributor's investment plan will
  - optimize investment across all categories of capital expenditure through a longer term, integrated approach
  - balance capital investments and O&M expenditures
  - reflect regional and smart grid considerations
  - serve present and future customers
  - place a greater focus on delivering value for money
  - align distributor and customer interests
  - support the achievement of public policy objectives
- good planning will ensure that the desired *performance outcomes* are being achieved

RRFE Performance Outcomes:
Customer Focus
Operational Effectiveness
Public Policy Responsiveness
Financial Performance

Board staff perspective: Keys to Success/Avoidance of Pitfalls [5.3.1] , [5.3.3]

Asset Management Process (AMP) & System Renewal {1of 4}

- System Renewal Investment generally follows two Modes:
  - Traditional Maintenance-based Mode
  - Proactive Capital Rebuild Mode

- A well developed AMP is key towards the goal of Lifecycle Optimization of a Distributor's assets and is characterized by:
  - clear plan/steps to operationalize stated goals and strategic directions
  - organization buy-in "top down" and "bottom up"

- the adopted mode for "Investment in System Renewal" by a Distributor should match:
  - the degree of sophistication of the asset condition assessment (ACA);
  - the degree of comprehensiveness of the asset Health Indices;
  - the accuracy of and confidence of predicting probability of individual asset failure for the various asset groups

Asset Management Process (AMP) & System Renewal {2 of 4}

- Traditional Maintenance-based Mode for System Renewal **is appropriate** for asset groups where:
  - only qualitative asset condition information is collected and asset registry for that asset group is in development; or
  - asset registry is developed, but asset replacement is based on typical useful life (TUL) adjusted based on qualitative ACA basis, where some asset groups traditionally exceeded TUL such as Overhead and Pad-Mounted transformers

Board staff perspective: Keys to Success/Avoidance of Pitfalls [5.3.1] , [5.3.3]

Asset Management Process (AMP) & System Renewal {3 of 4 }

- Proactive Capital Rebuild Mode for asset groups **is appropriate**, where:
  - Asset replacement is based on predicting accurately asset failures

Note: All distributors gave a road map on achieving a good basis for moving towards a Proactive Capital Rebuild Mode

- Proactive Capital Rebuild Mode for Distributors, with essential tools not fully developed (e.g., Asset Registry and Health Indexes) **is appropriate**, where:
  - Certain initiatives such as voltage conversion initiatives are based on variety of drivers and can be justified on the project's cost effectiveness
  - Some used specialized consultants to assess major assets such as a transformer station assessment to predict the window for targeting assets replacement including key system elements – the power transformers, breakers..etc

Asset Management Process (AMP) & System Renewal {4 of 4 }

– Proactive Capital Rebuild Mode for Larger Distributors is **appropriate** where:

- **Asset Registry** is fully developed using Geographic Information System (GIS), for each asset in all major asset groups – Poles, Overhead and Pad-Mounted Transformers, Overhead Line Switches, Pad-Mounted Switchgear, Underground Cables..etc

- **Health Index** (HI) framework is developed for each asset group based on quantitative multi-faceted parameters with appropriate weights leading to assignment of an HI to all assets in each of the noted asset groups

- **Probability of Failure function per asset group is modified by the HI scores** of all assets to produce a "Probability Dense Curve of Stress". For a HI of an Asset, its probability of failure can be established

- **Economic consequences of failure to customers can be evaluated.** The total cost of failure is the sum of the cost to the distributor and the cost of interruption of power to the customer. Minimizing the total cost is the criterion for asset replacement.

Optimization of Investments & Supporting Evidence

- An investment decision is normally based on an economic evaluation study with a horizon reflecting that asset life cycle

- The DSP with Investment that should directionally lead to cost savings e.g., system loss reduction or operating, maintenance and/or administrative efficiency gains, quantification of such savings should be identified for the entire 5 year planning period

Illustrative Example

- A Distributor's proposal for investment in System Renewal may reflect its decision for a given asset group to move away from its historical Maintenance Mode to a more Proactive Rebuild Mode where assets are replaced prior to failure. Effectiveness of the investment can be demonstrated by quantifying the forecasted benefits (including OM&A savings) over the entire planning horizon

Board staff perspective: Keys to Success/Avoidance of Pitfalls [5.4.1 g) and h)] & [5.4.5.2 C, c) & d)]

Evidence justifying investments e.g., in Smart Grid, New Tools (in support Asset Management Processes), or Customer Information Systems should be supported by:

- Appropriate business case for the initial decision; and
- Evidence to demonstrate how the net benefits in monetary terms (where practicable) and/or performance improvement will be monitored and reported on during the 5 year period.

Cost Minimization & Effectiveness of the Planning Process

- Evidence to illustrate that costs are minimized and efficiencies are achieved/achievable
  - In-house Efficiency Improvement Monitoring: improvement attained by comparing proposed project costs, with improved techniques, and comparable past project costs
  - Relevant Benchmarking Sources: proposed projects that can be readily assessed using available and relevant benchmarking sources

- Evidence demonstrating effectiveness of the planning process
  - relate proposed projects to DSP's objectives such as:
    - customer oriented performance e.g., reduced customer interruption
    - cost efficiency and effectiveness e.g., reduction in distribution system losses
    - asset/system operational performance e.g., replacement of glass insulators (with established poor performance), with newer polymer based insulators

Board staff perspective: Keys to Success/Avoidance of Pitfalls [5.0.4] , [5.4.1]

Customer Engagement

- For major initiatives getting meaningful feed back from customers requires a well structure preamble on the alternatives considered, and for each alternative its cost to the distributor, comparative benefit, and impact on the rates

Illustrative Example

- A business case established that due to load growth, a multi-year voltage conversion initiative is needed. The project requires conversion of the existing overhead low voltage at 4.16/2.4 kV to a new high voltage Distribution System at 27.6/16 kV, with two alternatives for the new system:
  - new underground 27.6/16 kV system; or
  - new overhead 27.6/16 kV system
- Seeking feedback from customers should include:
  - a preamble laying out the advantages and disadvantages of the two alternatives, as well as their respective costs and comparative benefits; and
  - then seek feedback as to which alternative the customers prefers.
- The application should then explain how the feedback informed the distributor’s plans

Board staff perspective: Keys to Success/Avoidance of Pitfalls [5.3.2] , [5.2.3], [5.4.1]

Distribution System Description (Existing & Future)

- Existing distribution system description and Fit/Gaps with its system performance indices outlining:
  - the distributor’s preferred system performance indices including reasons for selecting them, if additional to mandatory indices e.g., SAIFI, SAIDI; and
  - relating any Gaps to the relevant system performance indices

- Future state distribution system description including:
  - projected/desired system performance levels; and
  - the investments needed to effect the projected/desired results.

Thank you

Need information?

Email: IndustryRelations@ontarioenergyboard.ca

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Ontario Energy Board

Filing Requirements
for
Electricity Transmission
and Distribution Applications

Chapter 5

Consolidated
Distribution System Plan
Filing Requirements

March 28, 2013

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CHAPTER 5 CONSOLIDATED DISTRIBUTION SYSTEM PLAN FILING REQUIREMENTS

Glossary

Where applicable, definitions set out in the Distribution System Code (DSC) apply to terms used in these filing requirements. Certain other terms used here are explained below.

Distribution System Plan duration is the duration of a distributor's *Distribution System Plan*, which is a minimum of ten (10) years in total and comprised of an *historical period* and a *forecast period*

Forecast period is the last five (5) years of the *Distribution System Plan duration*, consisting of five (5) forecast years, beginning with the Test year

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

Historical period is the first five (5) years of the *Distribution System Plan duration*, consisting of five (5) historical years, ending with the Bridge year

REG investments accommodate the connection of renewable energy generation (including connection assets, expansions and/or renewable enabling improvements) the costs of which are the responsibility of the distributor as set out in the DSC. REG investments can be stand-alone or integrated into a project/activity; and are to be categorized for the purposes of section 5.4 in the same way as any other investment

Regional Infrastructure Plan is a document issued by the transmitter leading a Regional Planning Process that identifies forecast regional electricity service requirements, and describes and justifies the optimal infrastructure investments planned to meet those requirements

Regional Planning Process is a consultation involving distributors, transmitter(s), and the Ontario Power Authority convened for the purpose of exchanging information related to system planning, coordinating the modification of a regional electricity transmission system, and preparing and issuing a Regional Infrastructure Plan

System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system

System O&M are routine operations and maintenance activities carried out to sustain required distribution system performance to the end of the subject asset's service life

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements

5.0 Introduction

These filing requirements set out the information required by the Board under the renewed regulatory framework for electricity to assess distributor applications involving planned expenditures on distribution system and other infrastructure.[1] For the purposes of these filing requirements, a *Distribution System Plan* ("DS Plan") consolidates documentation of a distributor's asset management process and capital expenditure plan, where:

- an *Asset Management Process* is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus; and
- a *Capital Expenditure Plan* sets out and robustly justifies according to the Board's standard requirements for evaluation a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance expenditures.

Filing DS Plans consistent with these requirements will ensure that the Board's expectations for a distributor's planning are met; namely, that the DS Plan optimizes investments and reflects regional and smart grid considerations; serves present and future customers; places a greater focus on delivering value for money; aligns the interests of the distributor with those of customers; and supports the achievement of public policy objectives.[2]

Good distributor planning is an essential pre-requisite to the performance-based rate-setting approaches established under the renewed regulatory framework for electricity[3], and necessary to ensure that the performance outcomes the Board has established for electricity distributors are being achieved:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

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1 The renewed regulatory framework for electricity is a comprehensive, performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. See *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*; (the "*RRFE Report*"); p. 2.

2 *RRFE Report*; p. 1.

4 *RRFE Report*; p. 36.

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

DS Plan filings must enable the Board to assess whether and how a distributor has planned to deliver value to customers. One of the primary goals of DS Plans and by extension, hallmarks of good planning, is pacing and prioritizing capital investments in a manner that considers rate impacts. To facilitate the achievement of this goal, these filing requirements focus on the qualitative and quantitative information distributors can use to support their investment proposals that will best enable the Board to assess how a distributor has sought to control the costs and related rate impacts of proposed investments.[4]

5.0.1 Purpose of filing a Distribution System Plan

Good distributor planning is an essential pre-requisite to the performance-based rate-setting approaches established under the renewed regulatory framework for electricity. Filing a DS Plan with an application to the Board will provide information to the Board and interested stakeholders including but not necessarily limited to a distributor's:

- asset related performance objectives and approach to evaluating its performance relative to those objectives;
- approach to lifecycle asset management planning and the management of asset-related operational and financial risk; and
- plan for capital-related expenditures over the five-year forecast period.

5.0.2 Application and scope

These filing requirements apply to licenced, rate regulated electricity distribution utilities in Ontario when filing DS Plans as required by the Board as set out in section 5.1.3 of these requirements.

5.0.3 Framework for distribution system plans

The content of these filing requirements has been informed by the Board's expectations for distribution system planning under the renewed regulatory framework for electricity.

[4] *RRFE Report*; p. 36.

5.0.3.1 Integrated planning

An integrated approach to planning, whereby investments for system renewal and expansion, renewable generation connections, smart grid development and implementation, and regionally planned infrastructure are planned and optimized together, will provide the necessary foundation for distribution rate-setting under the renewed regulatory framework; help distributors to pace and prioritize projects; and support the achievement of the four outcomes for electricity distributors.[5]

5.0.3.2 Longer term planning horizon

Under the renewed regulatory framework, a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles, which are a minimum of five-years in expected duration.[6] This longer term approach should:

- enhance the predictability necessary to facilitate planning – including regional planning – and decision-making by customers and distributors;
- facilitate the cost-effective and efficient implementation of distributor DS Plans and thereby the achievement of customer service and cost performance outcomes; and
- help distributors to manage consumer rate impacts.[7]

5.0.3.3 Regional considerations

Planning the distribution system infrastructure in a regional context will help promote the cost effective development of electricity infrastructure in Ontario. Regional issues and requirements are to be considered in individual distributor system planning processes.[8] Accordingly, these filing requirements provide that where applicable, a distributor file information on the Regional Planning Process(s) in which it was a participant; on the Regional Infrastructure Plan provided by the transmitter; and information demonstrating that the Regional Infrastructure Plan has been appropriately considered and addressed in the development of the distributor's DS Plan.

5.0.3.4 Smart grid development and implementation

Under the renewed regulatory framework, smart grid development is expected to be integral to distribution system plans, a central focus of grid-enhancing innovation, and implemented on a coordinated regional basis to achieve economies of scope and

[5] *RRFE Report*; p. 31.
[6] *RRFE Report*; p. 31.
[7] *RRFE Report*; p. 10.
[8] *RRFE Report*; p. 39.

scale.[9] These filing requirements therefore include DS Plan information regarding, where appropriate:

- the activities a distributor has undertaken in order to understand their customers' preferences (e.g., data access and visibility, participating in distributed generation, and load management) and how they have addressed those preferences;
- the options a distributor has considered for facilitating customer access to consumption data in an electronic format;
- the mechanisms that facilitate "real-time" data access and "behind the meter" services and applications that a distributor has considered for the purpose of providing customers with the ability to make decisions affecting their electricity costs;
- the consideration a distributor has given to the investments necessary to facilitate the integration of distributed generation and more complex loads (e.g., customers with self-generation and/or storage capability);
- the technology-enabling opportunities a distributor has considered regarding operational efficiencies and improved asset management; and
- the distributor's awareness and adoption of innovative processes, services, business models, and technologies.[10]

5.0.4 The Board's evaluation of DS Plans

DS Plan filings must support the Board's assessment as to whether a distributor has and will continue to achieve the four performance outcomes the Board has established for electricity distributors as explained below. Section 5.4.5 explains the specific criteria the Board will use to evaluate whether a DS Plan and in particular the material[11] projects/activities proposed for cost recovery in a DS Plan address these four outcomes.[12]

Customer Focus

A DS Plan filing must demonstrate that distribution services are provided in a manner that responds to identified customer preferences. As indicated in the provisions that follow, this is accomplished by providing information on customer engagement to identify preferences; the value proposition the DS Plan represents for customers (economic efficiency and cost-effectiveness); and on the factors relating to customer preferences or input from customers and participants in a Regional Planning Process that were considered in the course of planning investment projects and activities.

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9 See *Report of the Board - Supplemental Report on Smart Grid* (EB 2011-0004); February 11, 2013 (the "*Smart Grid Report*"); pp. 4 – 5.

10 *Smart Grid Report*; pp. 9 – 16.

11 A project or activity is "material" if the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications* is met.

12 For details on the evaluation criteria and how the Board will use them to evaluate investments, see the *Smart Grid Report*; pp. 17 – 21.

Operational Effectiveness

DS Plans must show that a distributor's asset management and capital expenditure planning processes are designed to identify and take advantage of opportunities for continuous improvements in productivity and cost performance, while delivering on a distributor's explicitly stated system reliability and quality objectives.

Public Policy Responsiveness

A distributor's DS Plan must explain how the expenditure planning process has been integrated and rationalized so as to permit timely and appropriate expenditures in relation to a distributor's government-mandated obligations (e.g., in legislation or regulatory requirements imposed further to Ministerial directives to the Board).

Financial Performance

DS Plans must show that a distributor's financial viability and operational effectiveness will endure over the long term including by sustaining efficiencies gained through prudent capital-related expenditure planning and DS Plan execution.

5.0.5 Form of these filing requirements

To implement the policy objectives of the renewed regulatory framework, filing requirements related to Distribution System Plans, including information on planned investments related to investments to accommodate the connection of renewable energy generation (REG) and/or smart grid development activities and expenditures (see sections 5.1.2 and 5.0.3.4 respectively), have been consolidated in this Chapter 5 of the Board's *Filing Requirements for Electricity Transmission and Distribution Applications* (*CoS FRs*) Accordingly, these filing requirements replace the Board's *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*.

5.1 General & Administrative Matters

The form and the content of these filing requirements reflect the Board's conclusions in relation to distribution infrastructure planning. These filing requirements introduce a standard approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application.[13] As detailed in section 5.2, distributors filing a corporate 'Asset Management Plan' are expected to include and

[13] *RRFE Report*; p. 35.

clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.[14]

5.1.1 Investment Categories

A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure, examples of which are provided on Table 1.

Table 1 – Investment Categories & Example Drivers and Projects/Activities

	Example Drivers	Example Projects / Activities
system access	customer service requests	– new customer connections – modifications to existing customer connections – expansions for customer connections or property development
system access	other 3rd party infrastructure development requirements	– system modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
system access	mandated service obligations (DSC; Cond. of Serv.; etc.)	– metering – Long term load transfer
system renewal	assets/asset systems at end of service life due to: – failure – failure risk – substandard performance – high performance risk – functional obsolescence	– programs to refurbish/replace assets or asset systems; e.g: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	expected changes in load that will constrain the ability of the system to provide consistent service delivery	– property acquisition – capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – line extensions
system service	system operational objectives: – safety – reliability – power quality – system efficiency – other performance/functionality	– protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – automation (new/upgrades) by device type/function – SCADA – distribution loss reduction
general plant[1]	– system capital investment support – system maintenance support – business operations efficiency – non-system physical plant	– land acquisition – structures & depreciable improvements – equipment and tools – supplies – finance/admin/billing software & systems – rolling stock – intangibles (e.g. land rights; capital contributions to other utilities)

Note: 1. Includes only 19## series accounts.

[14] For the Board's conclusions in relation to consolidating and harmonizing its planning-related filing requirements see *RRFE Report*; p. 31.

- ***System access*** investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system
- ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.
- ***System service*** investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements
- ***General plant*** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

A project or activity involving two or more 'drivers' associated with different categories should be placed in the category corresponding to the 'trigger' driver. For example, a project triggered by the need to replace end of service life components in a distribution station should be considered a 'system renewal investment, even if in anticipation of future system requirements (a 'system service' driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.5), information on all drivers of a given project or activity should be used to justify proposed capital investments.

5.1.2 Investments related to renewable energy generation

Under the renewed regulatory framework, a distributor's investments to accommodate and connect renewable energy generation (i.e. REG investments) are integral to its DS Plan, which includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the *OEB Act*.

5.1.3 Time of filing

All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR Index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications.

5.1.4 Planning in consultation with third parties

5.1.4.1 Regional planning and consultations

Prior to filing a DS Plan and at a time and in a manner to be determined in consultation with the participants in a Regional Planning Process, a distributor must:

1. Provide regionally interconnected distributors (including host and/or embedded where applicable), the transmitter to which the distributor is connected and the OPA (where applicable) with information on:
   - forecast load at existing (and proposed, if any) points of interconnection;
   - forecast renewable generation connections and any planned network investments to accommodate the connections;
   - investments involving smart grid equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities; and
   - the results of projects or activities involving the study or demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned by the distributor over the forecast period.
2. Consult with regionally interconnected distributors (including host and embedded where applicable) and transmitter(s) to which the distributor is connected in preparing their DS Plan.

5.1.4.2 Renewable energy generation investments

Prior to filing a DS Plan, a distributor must:

1. Not less than 60 days (where REG investments are contemplated; 30 days otherwise) in advance of the date the distributor needs to receive the OPA letter for inclusion in an application, a distributor must submit information to the OPA in relation to the REG investments identified in their DS Plan and request in writing that the OPA provide a letter commenting on the information by a date that conforms to the distributor's filing timetable.
2. The Board expects that the OPA comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

5.1.5 Performance reporting

A distributor is to provide information on its performance in relation to its DS Plan as set out in section 5.2.3, including information on the achievement of the operational or other objectives targeted by investments the costs for which were approved in a previous application(s). Through its RRR filing, a distributor is also required to report annually on its performance, including in relation to reliability and any Performance Scorecard metrics established by the Board, including metrics related to asset management and capital expenditure planning as applicable.

5.2 Distribution System Plans

Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below.

5.2.1 Distribution System Plan overview

This section provides the Board and stakeholders with a high level overview of the information filed in the DS Plan, including but not limited to

a) key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

b) the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution

c) the period covered by the DS Plan (historical and forecast years);

d) an indication of the vintage of the information on investment ‘drivers’ used to justify investments identified in the application (i.e. the information should be considered “current” as of what date?);

e) where applicable, an indication of important changes to the distributor’s asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DS Plan filing; and

f) aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

Prior to filing, care should be taken to ensure that summary information is consistent with the detailed information filed in the following sections and elsewhere in the application.

5.2.2 Coordinated planning with third parties

To demonstrate that a distributor has met the Board’s expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate, a distributor must provide:

a) a description of the consultation(s), including

- the purpose of the consultation (e.g. Regional Planning Process);
- whether the distributor initiated the consultation or was invited to participate in it;
- the other participants in the consultation process (e.g. customers; transmitter; OPA);
- the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and
- an indication of whether the consultation(s) have or are expected to affect the distributor’s DS Plan as filed and if so, a brief explanation as to how.

b) where a final deliverable of the Regional Planning Process is available, the final deliverable; where a final deliverable is expected but not available at the time of filing, information indicating:

- the role of the distributor in the consultation;
- the status of the consultation process; and

- where applicable the expected date(s) on which final deliverables are expected to be issued.

c) the comment letter provided by the OPA in relation to REG investments included in the distributor's DS Plan (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.

5.2.3 Performance measurement for continuous improvement

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.

a) identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:

    - customer oriented performance (e.g. consumer bill impacts; reliability; power quality);
    - cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and
    - asset and/or system operations performance.

b) provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.[15]

    Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

c) explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

[15] The data should be calculated as stipulated in section 2.1.4.2 of the Board's Reporting and Record Keeping Requirements.

5.3 Asset Management Process

As noted in the Introduction, a distributor's asset management process is the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on its distribution system and general plant. The purpose of the information requirements set out in this section 5.3 is to provide the Board and stakeholders with an understanding of the distributor's asset management process, and the direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

5.3.1 Asset management process overview

This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates. The information provided should include but need not be limited to:

a) a description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments;

b) information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments; e.g.

- asset register
- asset condition assessment
- asset capacity utilization/constraint assessment
- historical period data on customer interruptions caused by equipment failure
- reliability-based 'worst performing feeder' information and analysis
- reliability risk/consequence of failure analyses.

Use of a flowchart illustration accompanied by explanatory text is recommended.

5.3.2 Overview of assets managed

Appropriate regulatory assessment of DS Plans requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed, including but not necessarily limited to

a) a description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan;

b) a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations;

c) information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled; and

d) an assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets

   - where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.

5.3.3 Asset lifecycle optimization policies and practices

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment, and should include but need not be limited to:

a) A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

   - a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;
   - a description of maintenance planning criteria and assumptions; and

- a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).

b) A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.

5.4 Capital Expenditure Plan

A distributor's DS Plan details the programme of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.

As noted above, a DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

5.4.1 Summary

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

a) information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver';

b) total annual capital expenditures over the forecast period, by investment category (see section 5.4);

c) a brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories;

d) a list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;

e) information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan;

f) a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan;

g) a brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects;

h) a list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);
- to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and
- to study or demonstrate innovative processes, services, business models, or technologies.

5.4.2 Capital expenditure planning process overview

The information a distributor should provide includes, but need not be restricted to:

a) a description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

b) if not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

c) a description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

d) if not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information; and

e) if different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).

5.4.3 System capability assessment for renewable energy generation

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) applications from renewable generators over 10kW for connection in the distributor's service area;

b) the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);

c) the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;

d) constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter); and

e) constraints for an embedded distributor that may result from the connections.

5.4.4 Capital expenditure summary

The purpose of the information filed under this section is to provide the Board and stakeholders with a 'snapshot' of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Note that where a distributor's internal investment planning framework does not align with the investment categories defined here, best efforts are expected to 'map' investments to these categories.

Despite the 'multi-purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or ‘trigger’) driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or activity for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

Table 2 illustrates how information filed under this section includes a distributor’s actual and forecast (i.e. proposed) capital expenditures over the historical and forecast periods. System operations and maintenance (O&M) costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. Note that ‘Plan’ expenditures over the historical period refer to a distributor’s previous plan for capital expenditures *after* adjustments (if any) occasioned by the Board’s decision on the relevant prior application.

Brief explanatory notes should be provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to ‘actual’ spending over the historical period. For example, a large expenditure over a relatively short period for a ‘one-off’ project (e.g. a distribution station) can cause a temporary ‘step change’ in category C spending compared to the trend in actual expenditures over the historical period.

While year over year ‘Plan vs. Actual’ variances for individual investment categories are expected, explanatory notes should be provided where

- for any given year “Total” ‘Plan’ vs. ‘Actual’ variances over the historical period are markedly positive or negative; or
- a trend for variances in a given investment category is markedly positive or negative over the historical period.

Table 2 – Capital Expenditure Summary

CATEGORY	Historical (previous plan[1] & actual)															Forecast (planned)				
	Test-5			Test-4			Test-3			Test-2			Test-1[2]			Test	Test+1	Test+2	Test+3	Test+4
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access																				
System Renewal																				
System Service																				
General Plant																				
Total																				
System O&M																				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in year 'Test-1' (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

5.4.5 Justifying capital expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

5.4.5.1 Overall plan

The Board's assessment of DS Plans includes the costs of material projects/activities included in the DS Plan, as well as the costs represented by the respective shares of the overall DS Plan budget allocated to each of the four investment categories. Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.5.2.

To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

- comparative expenditures by category over the historical period;
- the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;
- the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);
- information related to the distributor's system capability assessment (see section 5.4.3)

5.4.5.2 Material investments

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications*. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the Board's assessment according to the evaluation criteria set out below. The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

A. General Information on the Project/Activity

The following information is to be provided for any material project in order to facilitate and understanding of the quantum of the expenditure, timing, and contingencies associated with the project:

- total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates
- related customer attachments and load, as applicable
- start date, in-service date and expenditure timing over the planning horizon
- the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated
- if not evident from Table 2, comparative information on expenditures for equivalent projects/activities over the historical period, where available
- information on total capital and OM&A costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities
- where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular)

B. Evaluation criteria and information requirements for each project/activity

The Board's evaluation of material investments aligns with the outcomes set out in section 5.0.4. Efficiency, customer value, reliability and safety are the primary criteria for evaluating any material investment; other criteria pertaining specifically to grid modernization will be applied where applicable.

The Board's investment evaluation criteria and the qualitative or quantitative evidence that a distributor can use to demonstrate that an investment is consistent with these criteria are set out below.

1. *Efficiency, Customer Value, Reliability*
    a) identify the main 'driver' ('trigger') of the project/activity, and where applicable any secondary 'drivers'; related objectives and/or performance targets; and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment
    b) indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.2(c)

c) using, where applicable, quantitative and/or qualitative analyses of the project and project alternatives involving design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties)

   – explain the effect of the investment on system operation efficiency and cost-effectiveness
   – the net benefits accruing to customers as a result of the investment
   – the impact of the investment on reliability performance including on the frequency and duration of outages

   Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.

   Where a distributor’s choices as to technical design, component characteristics, how the work is carried out, etc. have been affected by a decision to configure a project to meet both a ‘trigger’ driver and one or more other drivers in a manner that affects cost as well as benefits, these effects should be highlighted.

2. *Safety*

   Provide information on the effect of the investment on health and safety protections and performance

3. *Cyber-security, Privacy*

   Where applicable, provide information showing that the investment conforms to all applicable laws, standards and best utility practices pertaining to customer privacy, cyber-security and grid protection

4. *Co-ordination, Interoperability*

   a) where applicable, explain how the investment applies recognized standards, referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

   b) describe how the investment potentially enables future technological functionality and/or addresses future operational requirements

5. *Economic Development*

   Where applicable, describe the effect of the investment on Ontario economic growth and job creation

6. *Environmental Benefits*:

   Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies

C. Category-specific requirements for each project/activity

As set out below, category-specific information and analyses should also be used to support a project/activity (or elements thereof as applicable).

a) *System access* – projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to requests by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions.

   In the event that the project involves replacing a distributor's system assets, there may also be asset life-cycle related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned.

   Information bearing on these issues should therefore be included in a distributor's justification of a project/activity in this category, including (where applicable) but not restricted to:

   - factors affecting the timing/priority of implementing the project
   - factors relating to customer preferences or input from customers and other third parties
   - factors affecting the final cost of the project
   - how controllable costs have been minimized
   - whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why
   - whether technically feasible project design and/or implementation options exist, whether these options were considered and if not, why not
   - where such options were considered and project decision support tools and methods described in response to section 5.4.2 (c) were used to help identify the proposed option, provide a summary of the results of the analysis, including where applicable:
     - the least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
     - the cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
       i. a project configured solely to meet the obligation; and

ii. the proposed project and where considered, technically feasible options to the proposed project that meet the same objectives.

- where applicable, the results of the 'final economic evaluation' carried out as per section 3.2 of the DSC
- where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered

b) *System renewal* – projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Generally, the lower the former and/or higher the latter, the more important it becomes to replace or refurbish the asset(s) sooner rather than later.

Hence, a distributor's discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits. On the other hand, a distributor may have considerable discretion over timing and priority where deteriorating asset condition has little or no impact on performance and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Information bearing on these issues should therefore be included in a distributor's justification of each sustainment project/activity, including (where applicable) but not restricted to:

- a description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to
  - the distributor's asset performance-related operational targets and asset lifecycle optimization policies and practices (i.e. filings in relation to sections 5.2.3 and 5.3.3)
  - information on the condition of the assets relative to their typical life-cycle; and performance record of the assets targeted by the project
  - the number of customers in each customer class potentially affected by a failure of the assets included in the project
  - quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
  - qualitative customer impacts (e.g. customer satisfaction; customer migration) with associated risk level(s)

  - the value of customer impact (e.g. high, medium, low) in terms of the characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (e.g. customer classes; customer access to backup service)

- other factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable; priority relative to other projects (this and other categories)
- identify the consequences for system O&M costs, including the implications for system O&M of not implementing the project
- identification of reliability and or safety factors that may have played a role
- where applicable and reasonable variation and/or uncertainty in the above factors exists, provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.
- where the proposed project meets the requirement for 'like for like' renewal and has been configured at extra cost to address other distributor planning objectives (e.g. development related objectives), provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

c) *System service* – projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Information used by a distributor to justify projects/activities in this category should include, but need not be restricted to:

- where measurable, an assessment of the benefits of the project for customers in relation to the achievement of the objectives of the investment; express the result (including where value is in the form of an avoided cost) in terms of cost impact to customers where practicable

- where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs
- description of how advanced technology has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.
- identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system
- identifying and explaining the factors affecting implementation timing/priority
- providing, where applicable and using the tools and methods described in response to section 5.4.2 (c), an analysis of project benefits and costs comparing the proposed project to a) doing nothing; and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.

  Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these 'qualitative' factors in relation to the proposed project and all alternatives, and that explains whether and how these factors affected the selection of the proposed project.

d) *General plant* – projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

   Information used by a distributor to justify material projects/activities in this category should include but need not be restricted to:

   - the results of quantitative and qualitative analyses (using the tools and methods described in response to section 5.4.2 (c) where applicable) of the proposed project/activity, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable;
   - For projects the capital cost of which substantially exceed the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

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

Orientation Session
Electricity Distributors Rebasing for 2015 Rates

Treatment of REG Investments

Harold Thiessen, Senior Advisor, Electricity Rates and Prices
July 24, 2014

Renewable Generation Investments: Legal Foundation

- The *Green Energy and Green Economy Act, 2009* amended the *Ontario Energy Board Act, 1998* to introduce a mechanism under section 79.1

  - **79.1** (1) The Board, in approving just and reasonable rates for a distributor that incurs costs to make an eligible investment for the purpose of connecting or enabling the connection of a qualifying generation facility to its distribution system, shall provide rate protection for prescribed consumers or classes of consumers in the distributor's service area by reducing the rates that would otherwise apply in accordance with the prescribed rules. 2009, c. 12, Schedule D, s. 14.

O. Reg. 330/09 - Rate Protection Formula

- Ontario Regulation 330/09 calculation of rate protection:

A = B – C

A = the amount of **rate protection** to be provided to prescribed consumers of classes of consumers in a distributor's service area

B = the **eligible investment cost** determined by the Board to be the responsibility of the distributor in accordance with the DSC , and

C = the amount the Board determines to represent the **direct benefits** that accrue to prescribed consumers or classes of consumers as a result of all or part of the eligible investment made or planned to be made by the distributor

Role of the IESO – O. Reg 330/09

- In accordance with Reg. 330/09, the Board determines the appropriate rate protection amounts, in aggregate and on a monthly basis, for each qualifying distributor that has made an “eligible” Renewable Energy Generation connection investment.

- The Board then issues a Decision and Order that sets out the following:

  - The aggregate and monthly rate protection amount to be collected by the Independent Electricity Systems Operator (“IESO”) from all market participants.

  - The monthly compensation payments the IESO is to make to each qualifying distributor identified in the Board Order based on the rate protection amounts determined by the Board in the respective distributor applications.

Rate Protection in 2014

- Total amount to be collected by the IESO in 2014 (EB-2014-0222, issued July 18, 2014) for the July 1 to December 31 period is 1,690,508 per month.

- The IESO monthly compensation payments to distributors are as follows:

Distributor	Amount
Hydro One Networks Inc.	$1,641,667
Enersource Hydro Mississauga Inc.	$ 6,084
Horizon Utilities Corporation	$ 707
Guelph Hydro Electric Systems Inc.	$ 3,856
PowerStream Inc.	$ 22,083
Thunder Bay Hydro Distribution Inc.	$ 1,537
Peterborough Distribution Inc.	$ 1,486
Veridian Connections Inc.	$ 1,928
Kitchener-Wilmot Hydro Inc.	$ 4,276
Haldimand County Hydro Inc.	$ 4,928
Niagara-on-the-Lake Hydro Inc.	$ 1,957

Green Energy Plans and Chapter 5 Filing Requirements: What changed, what stayed the same

- Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence (“DCL”), revised May 17, 2012 have been superseded by Chapter 5 of the Filing Requirements for Electricity Transmission and Distribution Applications, issued March 28, 2013.

Green Energy Plans and Chapter 5 Filing Requirements: What changed, what stayed the same

- **What changed?**
  - A distributor is no longer required to file a stand-alone Green Energy Act (GEA) Plan (Basic or Detailed).
  - With a Cost of Service Application, a distributor is required to file a Distribution System (DS) Plan, which includes Renewable Energy Generation (REG) investments.

- **What stayed the same?**
  - **DSC Amendments,** October 21, 2009, which assigned renewable generation cost responsibility between distributors and generators generation (EB-2009-0077) remain unchanged.
  - Three categories - Connection Assets; Expansions; Renewable Enabling Improvements (REI):
    - For connection assets, the generator bears 100% of the cost;
    - For expansions: (i) if the expansion is identified in a Board-approved plan or is otherwise approved or mandated by the Board, the distributor is responsible for 100% of the costs; and (ii) in all other cases, the distributor is responsible for the costs up to the “renewable expansion cost cap” ($90,000 per MW of capacity), any amount above that cap is the responsibility of the generator; and
    - For REIs, the distributor bears 100% of the cost.

Green Energy Plans and Chapter 5 Filing Requirements: What changed, what stayed the same

- **What stayed the same?**
  - Distributor is still required to provide the capacity of their distribution system to accommodate REG, including:
    - A summary of load and REG connection forecast by feeder/substation.
    - Information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or REG capacity.
  - Prior to filing a DS Plan a distributor must submit relevant REG information to the OPA and request that the OPA provide a letter commenting on the information, which is part of the DS Plan filing.

Green Energy Plans and Chapter 5 Filing Requirements: What changed, what stayed the same

- **Funding Mechanism**:
  - “Old” Green Energy Plan:
    - Funding Adder/Riders for Direct Benefits and Provincial Rate Protection (from the IESO).
    - 3 Renewable Generation Connection DVAs.
    - 3 Smart Grid DVAs.
    - Prudence review at next rebasing application.
  - Once a “new” DSPlan is filed under Chapter 5:
    - Discontinuation of existing DVAs
    - Disposition of existing balances
    - Accounting order required:
      - Variance account for ‘eligible investments’ under O. Reg. 330/09
    - Direct Benefit in Rate Base, Provincial Rate Protection (IESO) for remainder.

Direct Benefits – What changed, what stayed the same?

- **Chapter 5 Funding Mechanism – Direct Benefits:**
  - A Chapter 5 filing should include single/multi-year REG investments (as applicable), including the Direct Benefit portion for Board approval:
    - Renewable Enabling Improvements (REI) 6%
    - Renewable Expansions 17%
    - Or file a study to establish a custom percentage.
  - Multi-year approval process for REG investment remains the same as under the old methodology.
  - During IRM period following a Chapter 5 filing:
    - Direct benefit amount will be part of distribution rate base and not recovered through a rate adder.

Provincial Rate Protection – What changed, what stayed the same?

Chapter 5 Funding Mechanism – Provincial Rate Protection:

- A Chapter 5 filing should include the provincial rate protection amounts for 2015 test year and all forecast REG expenditures during the IRM period for Board approval:
  - Renewable Enabling Improvements 94%
  - Renewable Expansion 83%
  - Or file a study (as above)

- The Order to IESO includes:
  - Annual aggregate amounts to be collected by the IESO.
  - An order to collect an aggregate monthly amount from all ratepayers.
  - Direction to the IESO to remit the amounts noted to the qualifying distributors on a monthly basis.

Provincial Rate Protection – What changed, what stayed the same?

Chapter 5 Funding Mechanism – Provincial Rate Protection for past IRM Year Investments:

- Appendix 2-FA, 2-FB and 2-FC have been expanded to include 5 previous years to account for REG Investments made but not yet approved by the OEB.
  - Calculates the Annual REG amounts (past years) for IESO Recovery.
  - Calculates the Direct Benefit amounts (past years) for recovery through a Rate Rider.
- The Order to IESO would now include:
  - Annual aggregate amounts to be collected by the IESO and paid on a monthly basis for both past and future (approved) projects.

Appendix 2-FA: Renewable Generation Connection Investment Summary (over the rate setting period)

Appendix 2-FA

Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)

Enter the details of the Renewable Generation Connection projects as described in Section 2.5.2.5 [check] of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.
For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than five projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (pg 15, EB-2009-0349)

There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.
Scenario 1: Past Investments with No Recovery. The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive
revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate order.

Scenario 2: Investments in the Test Year and Beyond. Distributor plans to make investments in 2015 and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

REI Investments (Direct Benefit at 6%)	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project 1									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Appendix 2-FB: Calculation of Direct Benefits/Provincial Rate Protection

Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2015 and beyond, enter variables as in the application.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2011			2012			2013			2014			2015 Test Year		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	13%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt	4%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest	2%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest	6%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE	9%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection				$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO				$ -			$ -			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.

Note 2: For the 2015 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

Appendix 2-FB: PILs Calculation

PILs Calculation

	2014		2015		2016	
Income Tax	**Direct Benefit**	**Provincial**	**Direct Benefit**	**Provincial**	**Direct Benefit**	**Provincial**
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up						
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -

Appendix 2-FB – Net Fixed Asset & UCC calculation

		2014	2015	2016	2017	2018
Net Fixed Assets						
Enter applicable amortization in years:	25					
Opening Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization		$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)		-	$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2014	2015	2016	2017	2018
Opening UCC		$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -

Questions?

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

Orientation Session
Electricity Distributors Rebasing for 2015 Rates

Load Forecasting

Keith Ritchie, Project Advisor, Electricity Rates and Accounting
July 24, 2014

Significance of Load Forecasting in Cost of Service Applications

- Establish the sales volumes for the test period:
  - Number of customers
  - Consumption of customers (kWh)
  - (Peak) Demand of customers (kW)
- The drivers differ by classes of customers (Residential, GS < 50 kW, etc.)
- Used as allocators for recovery of costs from different customer classes
- Also used as the billing determinants for determining fixed and variable rates and for other rate riders
- Sales volumes (customers, kWh, kW) factors into revenue sufficiency/deficiency

Changes to Load Forecasting Resulting from Rate Design Project

- The Board is considering new options for distribution rate design
- The outcome is likely to affect load forecasting
- Until the Board establishes the new policy, the filing requirements have been based on the “traditional approach”
- Distributors can propose a new approach for the Board’s consideration

Forecasting Number of Customers

- Utilities have historical data on number of customers / connections by class
- Historical trends and levels generally an adequate basis for forecasting future growth
  - e.g. average annual growth rate (geometric mean), by customer class
  - Most utilities (and the communities they serve) have stable growth rates of about 0% to 2% per annum
- Adjustments may be used for unique growth patterns in individual classes, movement between customer classes, or changes in customer class definitions
  - Generally done for classes with smaller customer numbers and specific load profiles and demand (e.g. Large Use, Intermediate, Sentinel Lighting)

Forecasting Demand and Consumption - Approaches

- Normalized Annualized Consumption (NAC)
- Multivariate Regression (system purchased kWh)
- Multivariate Regression (by customer classes)
- Combination of these approaches seen beginning in 2013 cost of service applications
- Other approaches?

Forecasting Demand and Consumption

- Utilities generally forecast purchased consumption (kWh)
  - Purchases available monthly from IESO bills; customer billed demand often not available for a calendar month due to billing cycles
    - TOU data provides for calendar monthly data, but will need several years to collect sufficient data.
- Purchased kWh converted to billed kWh through loss factor
  - Purchased kWh = Billed kWh * (1 + loss factor)
- Estimated purchased kWh then allocated to customer classes based on historical patterns
- Weather sensitivity applied to certain classes (typically Residential and GS < 50 kW)
- For Demand-billed customers, purchased kW derived from estimated purchased kWh by class conversion factor
- For 2013-4 CoS: Several utilities used class-specific models for: Residential, GS < 50 kW, GS > 50 kW
  - Other classes forecasted through NAC or similar methods

Forecasting Demand – Multivariate Regression

- Demand = f(P, N, I, Weather, Seasonality, CDM, etc.)

Variable	**Description**	**Coefficient Sign**
P	Price	-ve
N	Number of customers/connections or size of community	+ve
I	Income or Economic Variable	+ve
Weather		
HDD	Heating Degree Days	+ve
CDD	Cooling Degree Days	+ve
Seasonality		
Days in Month	Number of Days in month; business days; peak period hours	+ve
Spring/Fall Flag	Binary Flag for spring and fall months to capture saddle period of energy consumption May overlap CDD/HDD or may capture other features of spring and fall saddle periods	-ve?
CDM	Variable to capture cumulative and persistent impacts of CDM programs	-ve
Other Variables?		
August 2003 Blackout	Binary flag for blackout (Southern Ontario LDCs)	-ve

Regression Output - Example

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.979498096
R Square	**0.959416519**
Adjusted R Square	**0.957640992**
Standard Error	2599144.111
Observations	168

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	2.55528E+16	3.6504E+15	540.3558299	7.6408E-108
Residual	160	1.08089E+15	6.75555E+12		
Total	167	2.66337E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-90392763.89	8420661.724	-10.73463902	1.37481E-20	-107022741.6	-73762786.21	-107022741.6	-73762786.21
Heating Degree Days	28385.21457	1222.256206	23.22362073	4.06933E-53	25971.37893	30799.05022	25971.37893	30799.05022
Cooling Degree Days	180663.8591	12686.48852	14.24065129	3.01994E-30	155609.2936	205718.4246	155609.2936	205718.4246
Ontario Real GDP Monthly %	178921.2574	63156.91427	2.832963888	0.005205712	54192.57116	303649.9437	54192.57116	303649.9437
Number of Days in Month	1999057.103	265489.4682	7.52970397	3.50381E-12	1474741.548	2523372.658	1474741.548	2523372.658
Spring Fall Flag	-2056228.894	532917.4883	-3.858437636	0.000165158	-3108688.454	-1003769.334	-3108688.454	-1003769.334
Number of Customers	1840.232909	213.4496505	8.621391064	6.11717E-15	1418.690869	2261.774949	1418.690869	2261.774949
Number of Peak Hours	57334.26505	13188.35313	4.347340754	2.4426E-05	31288.56635	83379.96374	31288.56635	83379.96374

Source: Waterloo North Hydro, 2011 EDR (CoS) [EB-2009-0144]

- High R^2
- Significant Regression
- All variables have coefficients with correct signs and are statistically significant at 95% c.i.

Regression Output – Analysis

- t-statistics of variables significant
  - ~ 1.96 for two-tailed test @ 95% c.i.
  - ~ 1.65 for one-tailed test @ 95% c.i.
- Variables have coefficients of appropriate signs?
  - +ve CDM, -ve Income, Customer Counts are unintuitive
- F-statistic
  - Overall significance of fit of the model
- R^2 and Adjusted R^2
- Analysis of Forecasts and Residuals
  - Residuals and Mean Absolute Percentage Error (MAPE) should be evaluated based on periodicity of model (e.g. monthly)
  - Patterns in residuals?
    - May be indicative of omitted variables

2.6.2 – Load Forecast Variance Analysis

- As a check on the accuracy of the distributor’s past load forecasts
- Variance analysis for customers/ connections, kWh, kW, revenues showing:
  - Historical Board-Approved vs. historical actuals
  - Historical Board-approved vs. historical actual (weather-normalized)
  - Historical actual (weather normalized) vs. preceding year
  - Last year historical actual (weather-normalized) vs. bridge year forecast
  - Bridge year vs. Test year

Appendix 2-IA – Load Forecast Summary

Appendix 2-IA
Summary and Variances of Actual and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

	2011 Board Approved	2011	2012	2013	2014 Bridge	2015 Test
Rate Class 1						
# of Customers	-					
kWh	-					
kW	-					
Variance Analysis						
# of Customers	-	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	-	0.00%	0.00%	0.00%	0.00%	0.00%
kW	-	0.00%	0.00%	0.00%	0.00%	0.00%
Rate Class 2						
# of Customers	-					
kWh	-					
kW	-					
Variance Analysis						
# of Customers	-	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	-	0.00%	0.00%	0.00%	0.00%	0.00%
kW	-	0.00%	0.00%	0.00%	0.00%	0.00%

- Summary and simple variance analysis of customers and demand (kWh/kW) by customer class
- Shows time trends and should aid in identification of deviations in customer or load forecast

Conservation and Demand Management – Relationship with Load Forecasting

- Since 2006, distributors have been delivering CDM programs
  - Own, Board-approved or OPA programs
  - Four-year CDM framework (2011-2014)
  - New Six-year CDM framework (2015-2020)
- Successful CDM reduces load (kWh and kW) relative to historical and relative to customer growth, and can have persistence into future periods.
- CDM results reported by OPA
  - Reported results are annualized (i.e., full year) impacts
    - Used for CDM targets and LRAMVA
    - Since programs in a year are rolled out throughout the year, first year impact will be less
      - Half-year for first year impact
      - Persistence is full-year impact
- Utility should account for impacts of CDM programmes in all years up to the test year
  - Issue of the accuracy of bridge and test year forecasts, trending from historical actuals and/or reflecting CDM initiatives to meet CDM targets
  - Impacts and persistence of then-current CDM programs reflected in historical actuals …
  - … but need to also estimate impacts of new CDM programs in bridge and test years

LRAMVA

- LRAMVA
  - New CDM Guidelines issued April 2012
  - Relate to 2011-2014 CDM targets that are a condition of a distributor's licence
  - Threshold for LRAMVA in test year will be the CDM adjustment that is factored into the load forecast in the cost of service test year
- CDM impacts measured by OPA or a third party in accordance with OPA guidelines
- For 2015, the Board must approve:
  - 2015 test year load forecast, including the persistence of historical 2011-2013 CDM programs, and expected 2014 and 2015 CDM programs impacts on the 2015 test year load forecast; and
  - Corresponding amounts used for establishing the 2015 LRAMVA threshold by class

LRAMVA and CDM Adjustment

- The amount to be used for the LRAMVA and the CDM adjustment are different, but related, amounts
- LRAMVA is based on net and annualized OPA reported numbers for persistence of CDM programs from 2011 to test year on the test year load forecast
- CDM adjustment on load forecast must recognize the following:
  - "real" 2015 CDM program impact on 2015 demand is less than annualized (½ year rule used as default)
  - 2011-2013 CDM program impacts are captured, in some form, in historical actuals
  - CDM adjustment is the additional impact beyond what is in the base forecast and reflecting that first year CDM program impacts are <u>not</u> full annualized impact as reported by the OPA

Appendix 2-I (Load Forecast CDM Adjustment Work Form)

- Spreadsheet first used in interrogatories in 2013 CoS applications to use results to data and to derive the related amounts for the LRAMVA and the CDM adjustment
- Updated for 2014 Cost of Service applications
- New Appendix 2-I for 2015 Cost of Service Applications
  - 2014 Bridge year is last year of 2011-2014 CDM program
  - New 2015-2020 CDM program through Ministerial Directive to OPA and Board in March 2014
    - Details on implementation still being worked out

Appendix 2-I - Outputs

	2011	2012	2013	2014 kWh	2015	Total for 2014	Total for 2015
Amount used for CDM threshold for LRAMVA (2014)	9,500.00	11,000.00	7,800.00	9,750.00		38,050.00	
2011 CDM adjustment (per Board Decision in 2011 Cost of Service Application)	8,000.00	8,000.00	8,000.00	8,000.00		32,000.00	
Amount used for CDM threshold for LRAMVA (2015)					20,833.33		20,833.33
Manual Adjustment for 2015 Load Forecast (billed basis)	-	-	3,900.00	9,750.00	10,416.67		13,650.00
Proposed Loss Factor (TLF)	3.25%	Format: X.XX%					
Manual Adjustment for 2015 Load Forecast (system purchased basis)	-	-	4,026.75	10,066.88	10,755.21		14,093.63

- Outputs from Appendix 2-I calculate the amount to be used for the LRAMVA and the related but different number for the CDM adjustment.
- If the base forecast is on a system purchased basis, then the loss-adjusted amount should be used; otherwise the billed CDM adjustment is used.
- The distributor must allocate the amounts for the LRAMVA and CDM adjustment to customer classes on a reasonable basis.

Questions?

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

Orientation Session
Electricity Distributors Rebasing for 2015 Rates

Setting Rates using Modified International Financial Reporting Standards ("MIFRS")

Donna Kwan, Project Advisor, Electricity Rates & Accounting
July 24, 2014

Agenda

1. Accounting Standards
2. Changes in Capitalization and Depreciation Expense Policy
3. Adoption of IFRS
4. Appendices to File in the Application
5. Review of Specific Chapter 2 Appendices
   - Fixed Asset Continuity Schedules and Depreciation Expense Schedules
   - Accounts 1576, 1575, 1508 Sub-account IFRS Transition Costs
6. Questions

Accounting Standards

- Filing requirements and Chapter 2 Appendices are structured for applicants that adopt IFRS January 1, 2015

- Accounting standards used in the rate application includes:
  - Modified International Financial Reporting Standards (“MIFRS”)
  - Canadian Generally Accepted Accounting Principles (“CGAAP”)

- The applicant should clearly specify the accounting standard used in each of the historical, bridge and test years in the evidence and Chapter 2 Appendices.

Key References for Interpreting Filing Requirements

- Report of the Board: Transition to IFRS (EB-2008-0408), July 2009
- Asset Depreciation Study for the Ontario Energy Board – Kinectrics July 8, 2010
- Addendum to Report of the Board: Implementing IFRS in an IRM Environment, June 13, 2011
- July 17, 2012 Board Letter - Changes to depreciation expense and capitalization policies
- June 25, 2013 Board Letter – Accounting policy changes for Accounts 1575 and 1576

Changes in Capitalization and Depreciation Expense Policy

- Per the Board's letter dated July 17, 2012, regulatory accounting changes for capitalization and depreciation expense policies for distributors remaining on CGAAP in 2012 were permitted effective January 1, 2012 and mandatory by January 1, 2013.

- These accounting changes should be consistent with the Board's regulatory accounting policies as set out for MIFRS (*Report of the Board, Transition to International Financial Reporting Standards*, the Kinectrics Report, and the Revised 2012 APH).

- These changes should be reflected prospectively in 2012 or 2013 for 2015 rates.

Capital Expenditures in the Application

Capitalization Policy

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

Capitalization of Overhead

- Must complete Appendix 2-D regarding overhead costs on self-constructed assets.

Appendix 2-D Example - Capitalized Overhead

Appendix 2-D

Overhead Expense

The example is for illustration purposes only

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2011 Historical Year	2012 Historical Year	2013 Historical Year	2014 Bridge Year	2015 Test Year
Cost Driver # 1	$ 100,000	$ 150,000	$ 160,000	$ 175,000	$ 180,000
Cost Driver # 2	$ 13,000	$ 14,500	$ 16,000	$ 15,000	$ 15,000
Cost Driver # 3	$ 250,000	$ 240,000	$ 260,000	$ 280,000	$ 287,000
Cost Driver # 4	$ 170,000	$ 170,000	$ 172,000	$ 175,000	$ 176,000
Total OM&A Before Capitalization (B)	$ 533,000	$ 574,500	$ 608,000	$ 645,000	$ 658,000

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2011 Historical Year	2012 Historical Year	2013 Historical Year	2014 Bridge Year	2015 Test Year	Directly Attributable? (Y/N)	Explanation for Change in Overhead Capitalized
employee benefits	$ 55,000	$ 62,000	$ 60,000	$ 65,000	$ 70,000	Y	No change in capitalization of employee benefits incurred on direct labour used to construct capital projects
costs of site preparation							
initial delivery and handling costs							
costs of testing whether the asset is functioning properly							
professional fees	$ 16,000	$ 20,000	$ 14,500	$ 13,000	$ 11,000	Y	No change in capitaliztion of professional fees directly related to contruction of plant
costs of opening a new facility							
costs of introducing a new product or service (including costs of advertising and promotional activities)							
costs of conducting business in a new location or with a new class of customer (including costs of staff training)							
administration and other general overhead costs	$ 23,000	$ 25,000	$ -	$ -	$ -	N	General overhead costs (e.g. executive management salary allocation not directly attributable to construction of new plant)
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ 94,000	$ 107,000	$ 74,500	$ 78,000	$ 81,000		

% of Capitalized OM&A (=A/B)	18%	19%	12%	12%	12%		

Depreciation/Amortization/Depletion in the Application

- Use the Board sponsored Kinectrics study or provide your own study to justify changes in useful lives.
- Must complete Appendix 2-BB regarding comparison of asset service lives.
  - Must explain if service life used is outside the minimum and maximum TULs in the Kinectrics Report.
- File depreciation policy or a written description of the depreciation practices followed and used in preparing the application:
  - Must provide a summary of changes to depreciation policy made since the last cost of service filing.
  - If further depreciation expense policy changes or changes in asset service lives are made subsequent to those made by January 1, 2013, the applicant must identify the changes and provide a detailed explanation for the causes of the changes.

Adoption of IFRS

- Accounting Standards Board extended the deferral of the mandatory adoption of IFRS to January 1, 2015.
- Therefore, assuming applicants adopt IFRS January 1, 2015, applications are expected to be filed under MIFRS for the test year. CGAAP applications are not expected.
- Bridge year may be presented using MIFRS and CGAAP.
- Historical years should be presented using CGAAP.

MIFRS in the Rate Application

- Must identify all material changes in the adoption of MIFRS that impacts the application. Impact should be quantified and an explanation of the changes as well as the details of the changes should be provided.
- If no material changes are identified, the applicant should provide a statement that indicates this and confirm that it has considered all possible impacts.

- Must complete Appendix 2-Y regarding summary of impacts to the components of revenue requirement from transition to MIFRS (e.g. rate base, operating costs, etc.)
  - Accordingly, applicants must identify financial differences and resulting revenue requirement impacts arising from the adoption of MIFRS as compared to CGAAP prior to capitalization and depreciation policy changes.

Appendix 2-Y Example - Summary of Impacts to Revenue Requirement from Transition to MIFRS

Closing NBV for 2014 and 2015 must agree to Appendix 2-BA Fixed Assets Continuity Schedule

Appendix 2-Y

Summary of Impacts to Revenue Requirement from Transition to MIFRS

The example is for illustration purposes only.

Revenue Requirement Component	**2015 MIFRS**	**2015 CGAAP without policy changes**	**Difference**	**Reasons why the revenue requirement component is different under**
Closing NBV 2014	$ 65,000,000	$ 66,000,000	-$ 1,000,000	
Closing NBV 2015	$ 68,000,000	$ 70,500,000	-$ 2,500,000	
Average NBV	$ 66,500,000	$ 68,250,000	-$ 1,750,000	Difference is due to the change of the capitalization policy and depreciation policy in 2012.
Working Capital	$ 1,300,000	$ 1,250,000	$ 50,000	Difference is due to the difference in OM&A expense as outlined below
Rate Base	$ 67,800,000	$ 69,500,000	-$ 1,700,000	
Return on Rate Base	$ 4,407,000	$ 4,517,500	-$ 110,500	Return on Rate Base is calculated as Rate Base X 6.5% (WACC). The difference in return on rate base is due to the differnce of rate base as noted above.
			$ -	
OM&A	$ 13,500,000	$ 12,800,000	$ 700,000	Difference is due to the change of the capitalization policy in 2012 and changes in OPEB expense from the adoption of IFRS.
Depreciation	$ 5,011,000	$ 5,505,000	-$ 494,000	Difference is due to the change of the depreciation policy in 2012
PILs or Income Taxes	$ 500,000	$ 685,000	-$ 185,000	Difference is due to the differences caused by accounting changes
			$ -	
Less: Revenue Offsets	-$ 1,080,000	-$ 1,080,000	$ -	
			$ -	
Insert description of additional item(s) and new rows if needed.			$ -	
Total Base Revenue Requirement	$ 22,338,000	$ 22,427,500	-$ 89,500	

Total Base Revenue Requirement must agree to the figure shown on RRWF

Appendices to File in the Application

- Two scenarios are generally expected:

Information to be filed in 2015 CoS Application	2015	Test
	2014	Bridge
	2013	Historical
	2012	Historical
	2011 and Prior	Historical

Accounting Policy Changes in 2012 and Adopts IFRS in 2015	Accounting Policy Changes in 2013 and Adopts IFRS in 2015
(Date of Transition to IFRS 2014)	
MIFRS	MIFRS
MIFRS and Revised CGAAP	MIFRS and Revised CGAAP
Revised CGAAP	CGAAP and Revised CGAAP
CGAAP and Revised CGAAP	CGAAP
CGAAP	CGAAP

- For the year that the applicant implemented changes to its capitalization and depreciation policies (2012 or 2013), the applicant must file two sets of appendices, one before and one after the policy changes.
- For the transition year (typically 2014), the applicant may file two sets of appendices, one under Revised CGAAP and one under MIFRS depending on the materiality of impacts.

Appendix 2-BA Fixed Asset Continuity Schedules

- For the year of capitalization and depreciation policy changes (2012 or 2013):
  - Two appendices should be filed, one before and one after the changes.
- For the transition year (typically 2014):
  - Two appendices should be filed, one under Revised CGAAP and one under MIFRS if the change between Revised CGAAP and MIFRS is material.
  - If the change from the accounting standards is not material, the applicant may choose to only provide one appendix under MIFRS. The applicant must also indicate the fixed asset net book value balance under Revised CGAAP, the total dollar value of the change and explain why it would not material.

- Establish the continuity of historic cost and accumulated depreciation by using the December 31, 2013 regulatory gross assets and accumulated depreciation as the opening balances as at January 1, 2014.
- Continuity statements should be reconcilable to the calculated depreciation expenses (Appendix 2-C) and presented by asset account.

Appendix 2-C Depreciation Expense Schedules

- Appendix 2-CA to 2-CE - For depreciation policy changes made January 1, 2012
- Appendix 2-CF to 2-CI - For depreciation policy changes made January 1, 2013
- Each set of appendices include depreciation schedules before and after the depreciation policy changes.
- Each set of appendices requires a recalculation to determine the average remaining life of the opening balance of assets on the date of making depreciation changes.
- In general, no further changes to the depreciation policy (i.e. assets' service lives) are expected after the Board mandated changes by January 1, 2013. Both sets of appendices assume this to be the case. If the applicant has made any changes to its depreciation policy subsequent to the Board mandated changes, applicants must identify the change, explain the nature of the change, the reason for the change, quantify the impact of the change, and quantify the depreciation expense before and after the change.

Appendix 2-EB, 2-EC Account 1576

- Account 1576 - To record the financial differences arising as a result of changes to accounting depreciation or capitalization policies permitted by the Board under CGAAP in 2012 or as mandated by the Board in 2013.
- The drivers of the change in closing net PP&E must be identified and quantified in Appendices 2-EB or 2-EC.

Appendix 2-EA Account 1575

- Account 1575 – Must capture all PP&E accounting changes made on transition to IFRS with the exception of those related to capitalization and depreciation that are captured in Account 1576.
- Provide a breakdown for quantification of any accounting changes arising from the transition to IFRS in relation to PP&E, including an explanation for each of the accounting changes made.

Accounts 1576 and 1575

- Account 1576 and Account 1575 cannot be used interchangeably and the applicant must follow the required accounting treatment applicable under each account.
- Applicants are typically expected to have balances in Account 1576 as a result of the Board mandated capitalization and depreciation policy changes under CGAAP.
- Applicants may also have balances recorded in Account 1575 for any further PP&E accounting changes made on transition to IFRS.
- Rate of return component to be applied to the balance in Account 1575 and Account 1576 (per Board letter dated July 25, 2013)
- Use of a separate rate rider (per Board letter dated July 25, 2013) for the disposition of the balances over the proposed disposition period.

Appendix 2-EC Example - Account 1576

The example is for illustration purposes only

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Reporting Basis	2011 Rebasing Year CGAAP Forecast	2011 IRM Actual	2012 IRM Actual	2013 IRM Actual	2014 IRM Forecast $	2015 Rebasing Year MIFRS Forecast $
PP&E Values under former CGAAP						
Opening net PP&E - Note 1				1,000,000	750,000	
Net Additions - Note 4				250,000	230,000	
Net Depreciation (amounts should be negative) - Note 4				-500,000	-490,000	
Closing net PP&E (1)				750,000	490,000	
PP&E Values under revised CGAAP (Starts from 2013)						
Opening net PP&E - Note 1				1,000,000	850,000	
Net Additions - Note 4				150,000	130,000	
Net Depreciation (amounts should be negative) - Note 4				-300,000	-290,000	
Closing net PP&E (2)				850,000	690,000	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-100,000	-200,000	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	200,000
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	65,000
Amount included in Deferral and Variance Account Rate Rider Calculation	-	265,000

Ensure PP&E values agree to Appendix 2-BA Fixed Assets Continuity Schedule, where applicable

WACC should be updated once it is updated and agreed/approved.

WACC	6.50%
# of years of rate rider disposition period	5

Appendix 2-U Account 1508, Sub-account IFRS Transition Costs

- An applicant should file a request for review and disposition of the balance in Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance.
- The balance requested should include actual audited incremental transition costs to date, the unaudited actuals for the bridge year and a forecast of any remaining costs to be incurred for the test year.
- Must explain how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.
- Account will remain open after disposition of the account balance.

Questions

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

Orientation Session
Electricity Distributors Rebasing for 2015 Rates

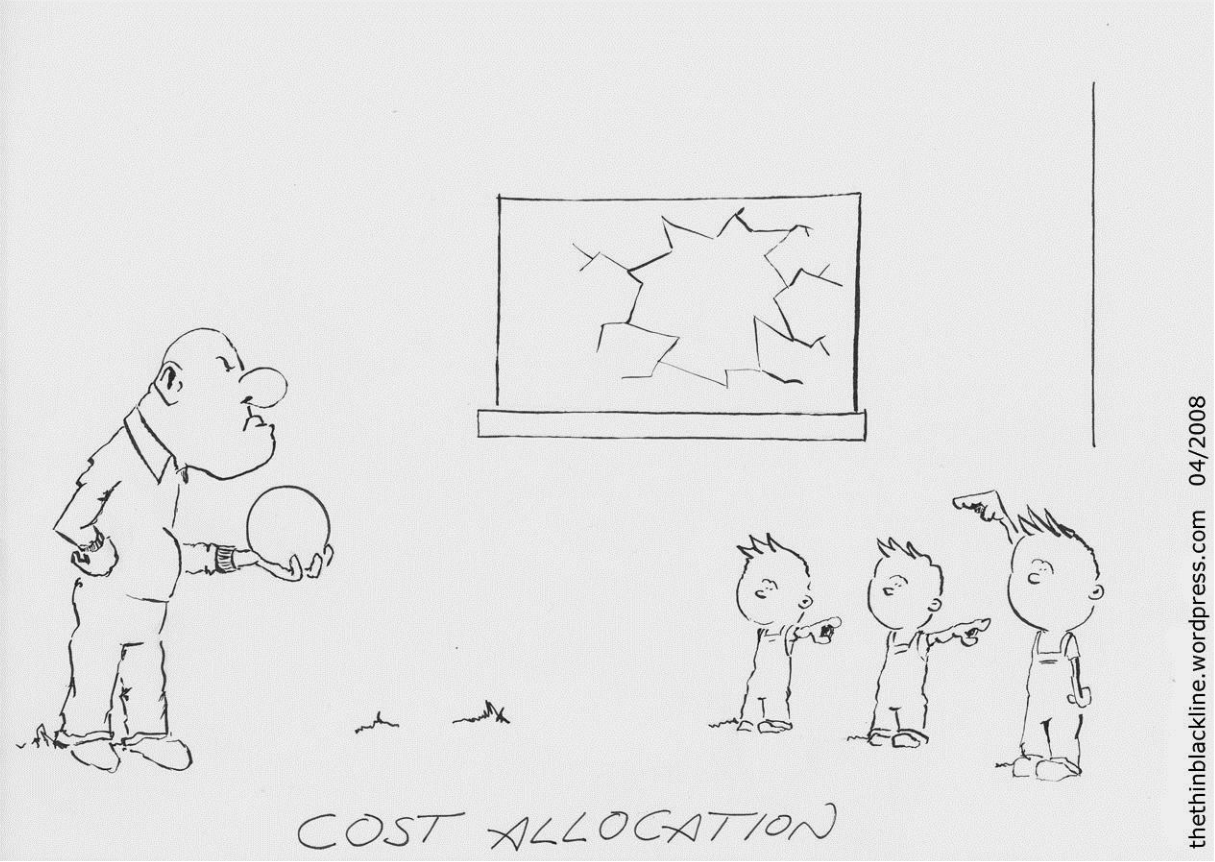
Cost Allocation & Rate Design

Review of what has Changed Since Last Rebasing

Vincent Cooney, Policy Advisor, Conservation & Operational Policies
July 24, 2014

Cost Allocation

Simple in theory, difficult in practice



Cost Allocation Filings: 2011-2015

What we'll cover:

- Policy Reviews (EB-2010-0219; EB-2012-0383) and Changes Since 2011
- Typical Exhibit 7 filings: 2011 and 2015
- Rate Rebalancing (Appendix 2-P)
- CA Model:
  - 2013 (v. 3)
  - 2014 (v. 3.1)
  - 2015 (v. 3.2)

Cost Allocation Policy Review

Report of the Board: "Review of Electricity Distribution Cost Allocation Policy", EB-2010-0219, March 31, 2011

- Required Changes since last COS
  - MicroFIT
  - Miscellaneous Revenue
  - Weighting Factors for Services and Billing
  - Transformer Ownership Allowance
  - Revenue to Cost Ratios

- Deferred for study and future development:
  - Allocation by Host Distributor to Embedded Distributor(s) (see slide 11)
  - Unmetered Loads (EB-2012-0383; Board report Dec. 2013)
  - Load Displacement Generation (EB-2013-0004)

Policy Review Changes: microFIT

- **not yet treated as a rate class;** goes to misc. revenue

- 11 USoA accounts relevant to microFIT cost responsibility
  - Allocation of 11 accounts, focus on Residential share
  - Calculation of unit cost: total allocated, per customer per month
  - Model accumulates costs in worksheet O-3.6

- Rate Design
  - Uniform microFIT rate is reviewed/updated annually in November
  - Currently: $5.40/customer
  - Source: updated O-3.6 from current applications, together with most recent cost allocation filing from other distributors

Policy Review Changes: Revenue Offset

Miscellaneous Revenue:

- Model allocates Revenue Offset amongst rate classes
- Reflect underlying costs to the extent possible
- Allocated amount is included in revenue to cost ratio for each class

Principle: allocation of revenue should be the same as the allocation of the underlying costs:

- SSS administration is now USoA 4082, allocated by customer count
- Account set-up is a sub-account of 4235, allocated by weighted number of bills
- Pole Rental reflects Primary versus Secondary distribution voltage
- Most M.R. accounts continue to be allocated by composite allocator (OM&A)

Policy Review Changes: Weighting Factors

Weighting Factors:

- Meters (installed cost per customer) and meter reading are calculated from inputs to I-7.1 and I-7.2
- Services (account 1855)
- Billing and Collecting (accounts 5315 – 5330, 5305, 5340)

Weighting factors are to be based on the applicant's examination of its own relative costs

  - Board has indicated that distributors should be using their own values (EB-2012-0383), rather than defaults, and CA model now includes dialogue to this effect.

Instructions and examples, included in Instructions worksheet of the model

Policy Review Changes: Transformers

- Revenue Requirement includes the (forecast) cost of transformers owned and provided by the distributor
  - Revenue Requirement does not include the “cost” of the Transformer Ownership Allowance (TOA)
- Revenue is calculated as (forecast) actual revenue, net of TOA
  - If some customers in a rate class provide their own transformer and others use a distributor-owned transformer, load forecast is split -- revenue is calculated partly at approved rate and partly at rate net of TOA
- Data inputs:
  - Revenue: worksheet I-6.1, changed in version 3
  - Cost: worksheet I-8, unchanged

Policy Review Changes: Ratio Policy Range

- Revenue to Cost Ratios
  - Range for ratios was narrowed for some classes

Service Class	Range
Residential	85 to 115 %
General Service < 50 kW	80 to 120 %
General Service 50 – 4999 kW	80 to 120 % *
Large User	85 to 115 %
Unmetered Scattered Load	80 to 120 % **
Street Lighting	70 to 120 % **
Sentinel Lighting	80 to 120 % *,**

*these ratios have changed

**the Board has indicated that these ratios *should* narrow with better data from changes in Report on Unmetered Loads, though not changed at this time

Policy Review Changes: Ratio Policy Range

- Model now generates "status quo" ratios:
  - Input forecast of charge determinants and current 2014 rates
  - Model calculates class revenue at current rates
  - Does not calculate a ratio using current rates

- Deficiency factor:

$$d = \frac{\text{total base revenue requirement}}{\text{distribution revenue at existing rates}}$$

- Status quo ratios, as if all rates increased by "d"

$$\frac{\text{class revenue at existing rates} \times d}{\text{class revenue requirement}}$$

Allocation by Host Distributor to Embedded Distributor

Memo to distributors, July 16, 2013 addressed this issue

If Separate Embedded Distributor Class, then

- No change to policy
- Continue to use CA Model and Appendix 2-P
- Appendix 2-Q is a useful framework, but not required to file

Else, Embedded Distributors subsumed in a GS Class

- Include as a customer of the class in data inputs: customer count, load forecast, revenue, etc.
- You must file Appendix 2-Q, though full detail not required

Unmetered Loads

CA Policy Review: Unmetered Loads (EB-2012-0383) 1/4

Affects Street Lighting, USL, and Sentinel Classes

Consultant's Report issued May 17, 2013:

- Included views of working group members
- Included recommendations that may warrant consideration in future COS applications:
  - Updating data
  - Communication
  - Conditions of Service
  - Cost Allocation Model instructions & examples
  - Terminology and Definitions

CA Policy Review: Unmetered Loads (EB-2012-0383) 2/4

Board Report later issued December 19, 2013

- *"Updated kW and kWh data should be used to update load profile date for the purpose of the distributor's next cost allocation filing with the Board…"*, i.e. next COS
- *"C of S should set out in reasonable detail how unmetered load customers are to file updated data with their distributors…"*
- *"Board expects distributors to assist unmetered load customers with understanding the regulatory context in which distributors operate…"*
- *"Board remains concerned with the allocation of costs to daisy-chain configured systems…"*
  - Policy work continues in this area
  - "Board expects that as a result of this consultation… …distributors will be able to narrow the revenue to cost ratio ranges for the street lighting class…"
- *"Board will include instructions or worksheets for the cost allocation model definitions for account, connection, customer, and device (as they related to unmetered loads)…"*

CA Policy Review: Unmetered Loads (EB-2012-0383) 3/4

Takeaways for 2015…

Notice of Amendment to a Code, issued May 15, 2014:

- Added requirements to section 2.4.6 of the Distribution System Code in respect of unmetered customers
- Takes effect Jan. 1, 2015

Verbatim amendments to s2.4.6 of the *Distribution System Code*:

- The following items in relation to unmetered load customers:
  - the **rights and obligations** an unmetered load customer has with respect to the distributor and the rights and obligations a distributor has with respect to an unmetered load customer;
  - the **process** an unmetered load customer must use **to** file its **updated data** with its distributor and what evidence is necessary for the distributor to validate the data;
  - the **process** the distributor will use to **update the bills** for an unmetered load customer; and
  - the **process** the distributor will use to **communicate and engage** with unmetered load customers in relation to the <u>preparation of cost allocation studies, load profile studies or other rate-related materials</u> that may <u>materially impact</u> unmetered load customers.

CA Policy Review: Unmetered Loads (EB-2012-0383) 4/4

And matters still under review for street lighting…

Following statements in December 2013 Report, the Board has moved to retain a consultant to further report on the “daisy chain” allocation issue:

- Consultant to prepare a report on the allocation of costs to different types of street lighting configurations and report on the appropriateness of the allocation and modeling
- At the time of printing, consultant had not yet been selected
- Expected to be selected and begin work end of July 2014; release report in fall 2014
- The Consultant’s Report will likely be posted for comment once completed

So what are the Implications for Distributors filing for 2015 rates?

- No formal changes regarding device-to-connection ratios this year, as it relates to revenue-to-cost ratios, that may change in subsequent years.
- Distributors encouraged to thoughtfully assess the appropriate allocation of costs to their street lighting customer class, regardless of configuration

Cost Allocation Filings: 2011-2015

- **Exhibit 7, then and now:**
  - Summary description, highlighting rebalancing (if any)
  - Similar to 2011

- **Appendix 2-P**
  - Provides summary tables for results of cost allocation study and proposed changes/rebalancing

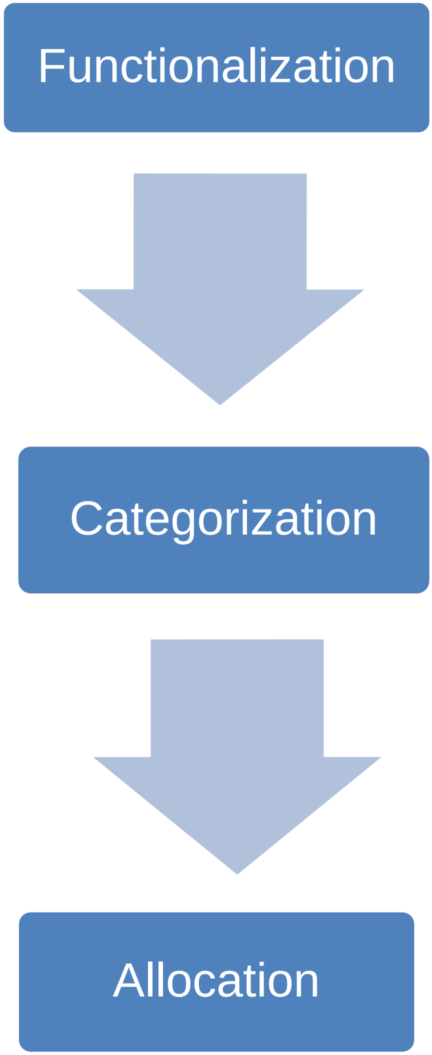
- **Appendix 2-Q**
  - Provides sharper focus on embedded distributor(s) than CA Model
    - Information required of host distributor, if no separate class of embedded distributor(s)

- **CA Model, then and now**
  - Similar to V1.2 (2011)
  - Incorporates policy changes as a result of EB-2010-0219 and EB-2012-0383
  - Includes more instructions reflecting experience in other applications

Cost Allocation Framework

Conceptual Framework unchanged, basic CA Model little changed

- Customer Classes: worksheet I2
- Functionalization
  - Preparing USoA account forecast data
  - Worksheets: I-3 (trial balance forecasts); I-4 (asset sub-accounts where required)
- Categorization:
  - Accounts by demand-related, customer-related, partial (min. system)
  - Worksheets: E1; I-5.1 cell D21
- Allocation:
  - Allocator for each account: policy effected in worksheet E-4
  - Allocator values (allocation to all classes adds to 100%): worksheet E-2
  - Data Input: worksheets I-5, I-6, I-7, I-8, I-9
  - Detailed calculations: worksheets O-4, O-5, O-6, O-7
  - Main results: worksheets O-1, O-2
  - Other results: O-2.1 – 2.5; O-3.1 – 3.5
  - microFIT unit cost (worksheet O-3.6) new with version 3.0



Rate Rebalancing (Appendix 2-P)

- Applicant provides Appendix 2-P:
  1. Approved revenue-to-cost ratios
  2. Status quo ratios
  3. Proposed ratios

- Policy is unchanged: if any status quo ratio is outside the Board's policy range, proposed rates must adjust to produce a ratio in the applicable range

- Applicant may propose:
  - movement within range
    - expected outcome: direction of any movement is toward 100%
  - movement to include subsequent (IRM) years to mitigate impacts
    - proposed and approved as part of the COS proceeding

CA Model: version 3.1 vs. 3.0

Version 3.1

- Updated list of accounts in worksheet I-3 ‘Trial Balance’
  - Removes formula from version 3.0 for annual recovery of PP&E balance
  - Recovery of Accounts 1575, 1576
    - Memo June 25, 2013
- Direct Allocation
  - provides for inclusion of overhead costs in revenue requirement
- Easier to use:
  - Clearer instructions
    - especially re Weighting Factors
  - New colour coding on worksheet I-3

CA Model: version 3.2 vs. 3.1

Version 3.2

- Additional instructions for clarity
  - Sheets I4 (Asset Break Out) and I6.1(Revenue)

- Formula in cell C148 of sheet I9 (Direct Allocation) has been corrected so that the associated PILs, Return on Debt and Return on Equity for directly allocated costs are calculated based on the NBV in all instances.

Questions?

Intervenor Review of Electricity Distributor Rate Applications

July 24, 2014

Jay Shepherd

for School Energy Coalition

School Energy Coalition

- **Who We Are**
  - Coalition of seven school board organizations
  - All school boards are active members
  - 5000 schools with 2 million students
  - Spend $600 million per year on energy
  - Details posted on the Board's website
- **Intervention Principles**
  - Always look for the win-win solution
  - "Walk softly but carry a big stick"
  - Think long term

Electricity Intervenors

- **Organizations:**
  - Active ratepayer groups in LDC applications: VECC, Energy Probe, SEC, AMPCO and CCC
- **People:**
  - Experienced consultants/lawyers
  - Old
- **Division of Responsibility**

Goals for the Review

(in order of priority)

- **Knowing the Utility**
  - **now more important under RRFE**
- **Hearing/Adjudication**
- **ADR**
- **Interrogatories**

Preliminary Work

- Website, Newspaper stories, Google search, etc.
- Yearbook data for all years
- Previous applications, results, rates
- People: Who do we know?
- Customer meetings/feedback
- “Knowing the utility”

Within the Application

- Financial Statements (Jay)
- Strategic/Business Plan
- Rating agency reports
- Shareholders’ Agreement/Direction
- Asset Condition Assessment and AMP
- IT Plan or Strategy
- Tax returns (Randy)
- Other “non-regulatory” documents

Components

- **Revenue Requirement**
  - OM&A issues (pattern, FTEs, affiliates)
  - Rate Base issues (opening, capex, dep’n)
  - Cost of Capital issues (debt rate, taxes)
- **Revenue Forecast** (load, customers)
- **Deficiency/Sufficiency**
- **Who Pays**
  - Cost Allocation (RTC, anomalies)
  - Rate design (fixed charges)

Central Issues

- **Influenced by RRFE**
- **Utility strengths and attributes, e.g.**
  - **Size and customer mix**
  - **Community**
  - **People**
- **Problems and proposed solutions, e.g.**
  - **Financial history**
  - **Growth/decline**
  - **Past underinvestment**

Comparative Data

- **Valuable diagnostic tools**
  - Identify potential problem areas
  - Test against evidence for consistency
  - "Outcomes-based" analysis
- **Comparative Rates the most important**
  - Captures all aspects of costs, but not granular enough
- **Rate Base and Capital Spending**
  - e.g. Capex/depreciation ratio each year

Comparative Data

- **OM&A Metrics**
  - OM&A or FTE per customer
  - Spending ratios (e.g. maint. vs. G&A)
  - Individual line items, esp. trends
- **Other Metrics**
  - Components of revenue (e.g. by class)
  - Compensation levels
  - Debt/equity ratio (leveraging)

Interrogatories

- What are we looking for?
  - Documents referred to (or omitted)
    - Sometimes prior versions
  - Explanations
    - Missing data, steps, or confusion
    - Comparative data
- Clear answers simplify the TC (call)
- Challenges facing this LDC
  - Show investigation and analysis
  - Thoughtful plan to deal with them

Technical Conference

- Usually first contact with intervenors
- Not cross-examination, but tougher than IRs
- Model TC is a dialogue
- Point is to save the Board panel from wasting their time

ADR –The Process

- **What is actually going on?**
  - **Most COS applications can be settled**
    - **Equality of negotiating strength (hearings are not so bad, but everyone benefits if you don't get there)**
    - **Willingness to compromise/listen – on both sides**
    - **RRFE may make settling some issues more difficult**
  - **Opportunity vs. challenge**
- **Steps**
  - **Exchange of information/dialogue**
  - **Intervenor caucus – application of standard metrics and formulae to the specific situation**
  - **Offers back and forth**
  - **Documenting any agreement**

ADR – Negotiations

- **Offers**
  - Issue by issue – revenue requirement usually first
  - Deficiency based packages (looking for savings)
- **Settlement of other issues**
  - Asset management plan and longer term issues
  - Cost allocation and rate design
  - Deferral and variance accounts
- **Intervenor point of view**
  - Result by agreement vs. result by decision
  - ADR positions vs. Hearing/Argument positions
  - Comparative data increasingly influential
  - AMP and similar discussions a big unknown

Oral Hearings

- **Cross-examination**
  - Bias in favour of the cross-examiner
  - Utility counsel has limited freedom to protect you
  - Good questioners are well prepared
- **Approach**
  - Don’t “play the game” - use your natural advantage
  - Credibility not easily lost, but also not easily regained
  - Pay close attention to questions from Board members – some are becoming more activist

Intervenor Review of Electricity Distributor Rate Applications

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