2017 Cost of Service Applications
Case Managers

Distributor	Docket Number	Case Manager [1]
January 1 Rate Year		
Brantford Power Inc.	EB-2016-0058	Martha McOuat
Canadian Niagara Power Inc.	EB-2016-0061	Martin Davies
Lakefront Utilities Inc.	EB-2016-0089	Georgette Vlahos
Renfrew Hydro Inc.	EB-2016-0166	Georgette Vlahos
Westario Power Inc.	EB-2016-0113	Colin Schuch
May 1 Rate Year		
Atikokan Hydro Inc.	EB-2016-0056	Birgit Armstrong
E.L.K. Energy Inc.	EB-2016-0066	Donald Lau
London Hydro Inc.	EB-2016-0091	Harold Thiessen
Northern Ontario Wires Inc.	EB-2016-0096	Colin Schuch
Peterborough Distribution Inc.	EB-2016-0100	Martha McOuat
Thunder Bay Hydro Electric Distribution Inc.	EB-2016-0105	Martin Davies
Welland Hydro-Electric System Corp	EB-20016-0110	Lawrie Gluck

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

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

Orientation Session for Cost of Service Applicants

RRFE Overview and Introduction

Ted Antonopoulos

July 28, 2016

Outline

- 2014-2016 Cost of Service
  - Summary
  - Staff observations from decisions
- The Rate Handbook
  - Overview of RRFE
  - Structure of a rate application
  - Customer engagement
  - Planning
  - Performance metrics
- Key features of a good application
- Process improvement initiatives
- Key policy developments
- Roadmap to the day

2014-2016 Cost of Service
Summary

- The OEB has completed three years of cost of service reviews under the RRFE
- 23 LDC applications have been reviewed and decided
- Most rate applications resulted in settlements
  - OEB found that the settlements reflected the four RRFE outcomes in the context of this transitional period
  - Several settlements were presented to the OEB at an oral hearing
- Examples of unsettled issues in 2014-2016
  - Working capital allowance
  - OM&A
  - Rate design for >50kW
  - Interest rate on long-term affiliated debt
  - New building

2014-2016 Cost of Service
Staff Observations from decisions

- OEB found that customer engagement activities going forward should focus on providing customers with more specific information as to the costs of proposals

- In two Custom IR applications decided upon to date, the OEB confirmed its expectations for explicit incentive adjustments, cost and productivity benchmarking support, and value to customers commensurate with the forecast spending.

The Rate Handbook

- Overview of RRFE
- Structure of a Rate Application
- Key Components
  - Business Plan
  - Customer Engagement
  - Planning
  - Outcomes
  - Performance Metrics
  - Performance Scorecards
  - Benchmarking

The Rate Handbook
Overview of the RRFE

- A focus on outcomes that matter to customers
- The foundations of the RRFE:
  - customer engagement
  - robust planning
  - Continuous improvement and performance measurement
- Retention of certain other policies – rate mitigation, costs of capital, cost allocation etc.
- Flexibility for different business environments

The Rate Handbook
Structure of a rate application

- Business plan:
  - describes overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the application and the plan to meet them.
  - is supplemented and supported by the associated plans, reports and documentation (including system plans, capital and operational plans, programs, benchmarking, external reviews and customer engagement) which form the core of the rate application.
- Historical and forecast data:
  - Data filed in support of an application facilitates a rigorous review of the application and ensures continuity in the regulation of each utility over time.
- Rate models:
  - facilitate review process
  - are one of the tools the OEB uses to enhance the efficiency, consistency and accuracy of the process.

The Rate Handbook
Customer Engagement

- An application must provide
  - an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities.
  - how the utility has reflected both operational experience and customer input in the development of its plans.

- In reviewing customer engagement, the OEB will consider:
  - The forms of customer engagement used, their quality and effectiveness
  - The quality of the utility's analysis of customer input
  - Whether and how customer input has informed the utility's planning
  - Whether and how the utility's plans deliver benefits which address customer needs and preferences

The Rate Handbook
Planning

- Robust planning is one of the foundations of the OEB's RRF.
- System plan complements and supports the utility's overall business plan.
- In a cost of service proceeding the OEB will consider the entire five year DSP.
- The DSP must have the following key characteristics:
  - Integration
  - Value
  - Effective asset management
  - Optimization (including pacing and prioritization)

The Rate Handbook
Performance Metrics

- These are the quantitative and/or qualitative measures which will be used to assess whether the outcomes have been achieved.
  - Scorecards
    - ✓ Performance on each measure
    - ✓ Drivers
  - Beyond the scorecards
    - ✓ Other performance improvement targets
    - ✓ PEG forecasting model

Key Features of a good application

- An application must provide:
  - An overview of customer needs, preferences and expectations learned through the utility's customer engagement activities (Guelph)
  - How the utility has reflected its operational experience and customer input in the development of its plans (Entegrus and Festival)
  - Well supported and clearly articulated requests (Entegrus)
  - Easy to follow structure, e.g. headings matched with the Filing Requirements (Guelph)
  - Clear identification of how actions arising out of any previous decisions have been incorporated into the application (Waterloo North)
  - Comprehensive presentation, explanations and reconciliation of technical matters, such as PILs (Waterloo North)

Process Improvement Initiatives

Goal: *Business strategies, objectives and priorities of LDCs come to the forefront of the hearing process*

- Presentations have become common among CIR proceedings
  - Should not be a regurgitation of the application but rather the vision of senior leadership
  - May become an element for cost of service applications as well
- For COS, aim is for procedural steps that lead to a more focussed hearing;
  - Issues list – later in the process, attempt to better define issues Should there be a two stage process?
  - Notice - how to ensure that discrete customer groups are notified
  - Flexible tools – non-transcribed TCs, conference calls
  - Community Meetings – should be expected in cost of service cases

Key Policy Developments

- Rate design – shift to fully fixed rates for residential customers
- Advanced capital module – evaluate the need for capital projects over IRM term in COS application
- Working Capital Allowance – new default of 7.5% based on review of practices and mandatory monthly billing.

Roadmap to the day

- Agenda
  - Session 1: RRFE Overview and Process
  - Session 2: DSP and Load Forecast
  - Session 3: Cost Allocation and Appendices/Models
  - Session 4: PEG Forecasting Model
    Accounting matters
    Intervenors' perspective

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

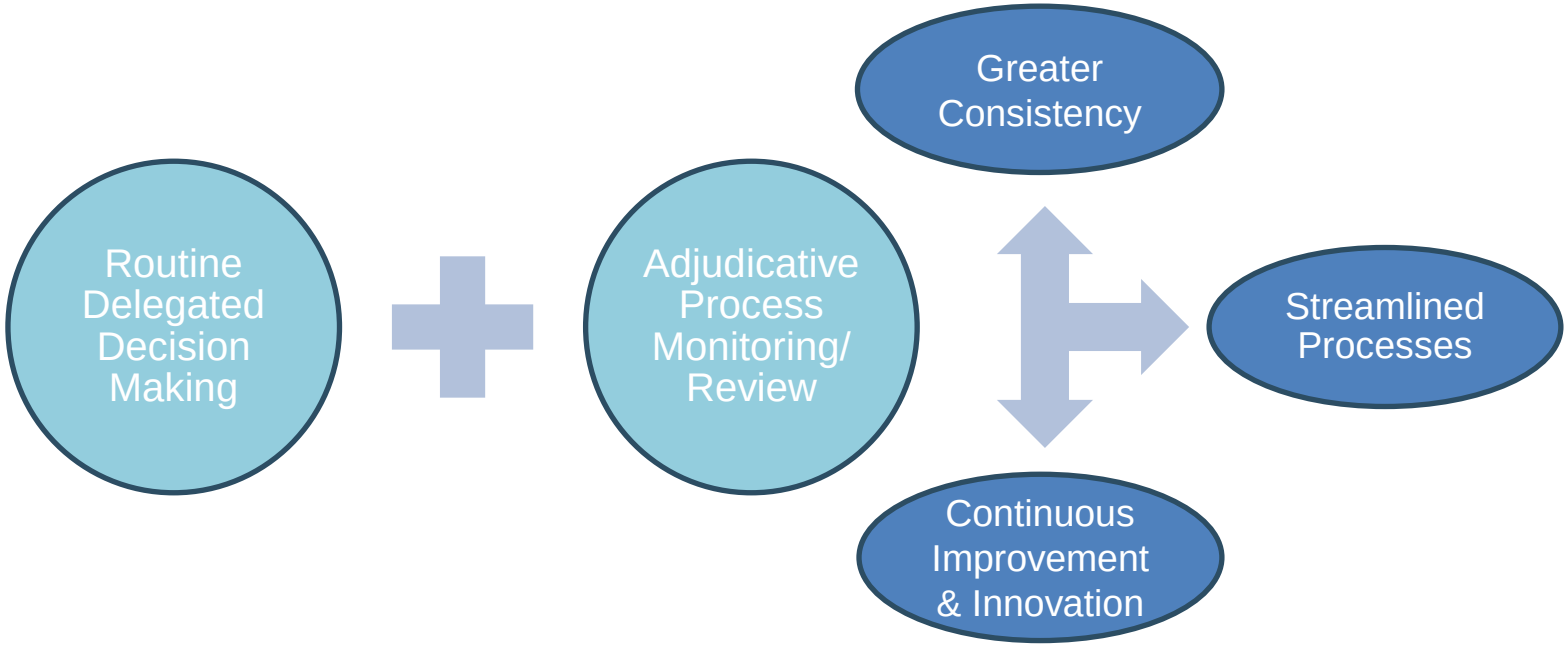
Orientation Session
Electricity Distributors Rebasing for 2017 Rates
Role of Registrar & Consumer Engagement Framework

Kristi Sebalj, Registrar
July 28, 2016

Agenda

1. Registrar Role
2. Consumer Engagement Framework
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

- **Procedural Order No. 1**
  - Decision with respect to intervenor and cost eligibility requests
  - Set out procedure for hearing

Registrar – Adjudicative Process

- Support and enhance regulatory efficiency/consistency by:
  - Monitoring adjudicative process
  - Identifying and addressing 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

Consumer Engagement Framework - Context

OEB has been undertaking a review of how customers participate in its processes for several years in phases:

Step 1: Strengthen the Rules (completed in 2014)

- Examined the OEB's approach to intervenor status, cost eligibility and cost awards
- Implemented procedural and administrative changes (Intervenor Phase 1 Consultation)

Step 2: Test New Approaches to Customer Engagement (2013-16)

- Reviewed/revised legal notices
- Piloted community meetings for larger rate hearings

Step 3: Review Best Practices in Customer Engagement (late 2015/16)

- Evaluated alternative models to OEB's current approach - jurisdictional review
- Developed a new Consumer Engagement Framework which adopts best practices to ensure effective and transparent consumer representation in OEB processes

Step 4: Implement the New Customer Engagement Framework (2016-18)

- Get input from customers, intervenors and other stakeholders
- Roll-out the various tools for consumer engagement
- Assess and evaluate each tool

Consumer Engagement Framework

- The framework is the OEB's new approach to engage with and empower energy consumers

- Goal: Ensure that the people who pay the energy bills have a stronger and more meaningful voice throughout OEB decision-making

- Framework designed to:
  - build consumer **awareness** about the OEB
  - provide consumers with simple and meaningful **information**
  - make it easier for consumers to **access** and participate in OEB processes

Consumer Engagement Framework Deliverables

The OEB's regulatory process is easily understood by Ontario electricity and natural gas consumers

Residential and small business consumers have access to and can meaningfully participate in OEB hearings

The OEB has effective mechanisms to ensure the voice of the consumer is heard

OEB decisions consider the views of the consumers impacted

Consumer Engagement Framework

- What it is…
  - Complementary with existing tools
  - More systematic
  - Getting the customer point of view
  - Capacity building and energy literacy
  - Decision making that considers the views of all customers

- What it is NOT …
  - Replacement for intervenors
  - Overlap with utility responsibilities
  - One size fits all

Community Engagement Framework Tools

- Tools to address awareness, information, and access

- Existing tools include:
  - Consultation by utility: Already required by OEB (RRFE)
  - Legal Notice: OEB developed a shorter, plain-language notice
  - Letters of Comment: via e-mail, consumer website, regular mail and at a community meeting
  - Intervention

- New tools include digital, written, and in-person tools as well as a new suite of tools designed to bring the process into local communities

New Tools

- Enhanced Consumer Website
  - Central “one stop” gateway for consumer information, video tutorials and other tools about OEB adjudication
  - Application-specific information, impacts by customer group/class, utility information, details about the process
  - Participation - clear, simple, plain language information and video tutorials about how to get involved and be heard

- Guidebook/Quicktools
  - Plain-language, easy-to-use guide made up of “quick tools” advising consumers how to get involved
  - Available in hard copy, at public meetings, on consumer website, through distributors, and supplemented with interactive media such as videos and tutorials

New Tools (cont'd)

- Notification
  - To increase awareness
  - Goes beyond legal notice and leverages multiple channels: OEB website, utility websites, email, social media, direct mail, bill, other

- Process Counsel
  - Dedicated OEB customer contact person who knows what applications have been filed, how OEB's decision making processes work, and how consumers can get involved

Local Community-Based Tools

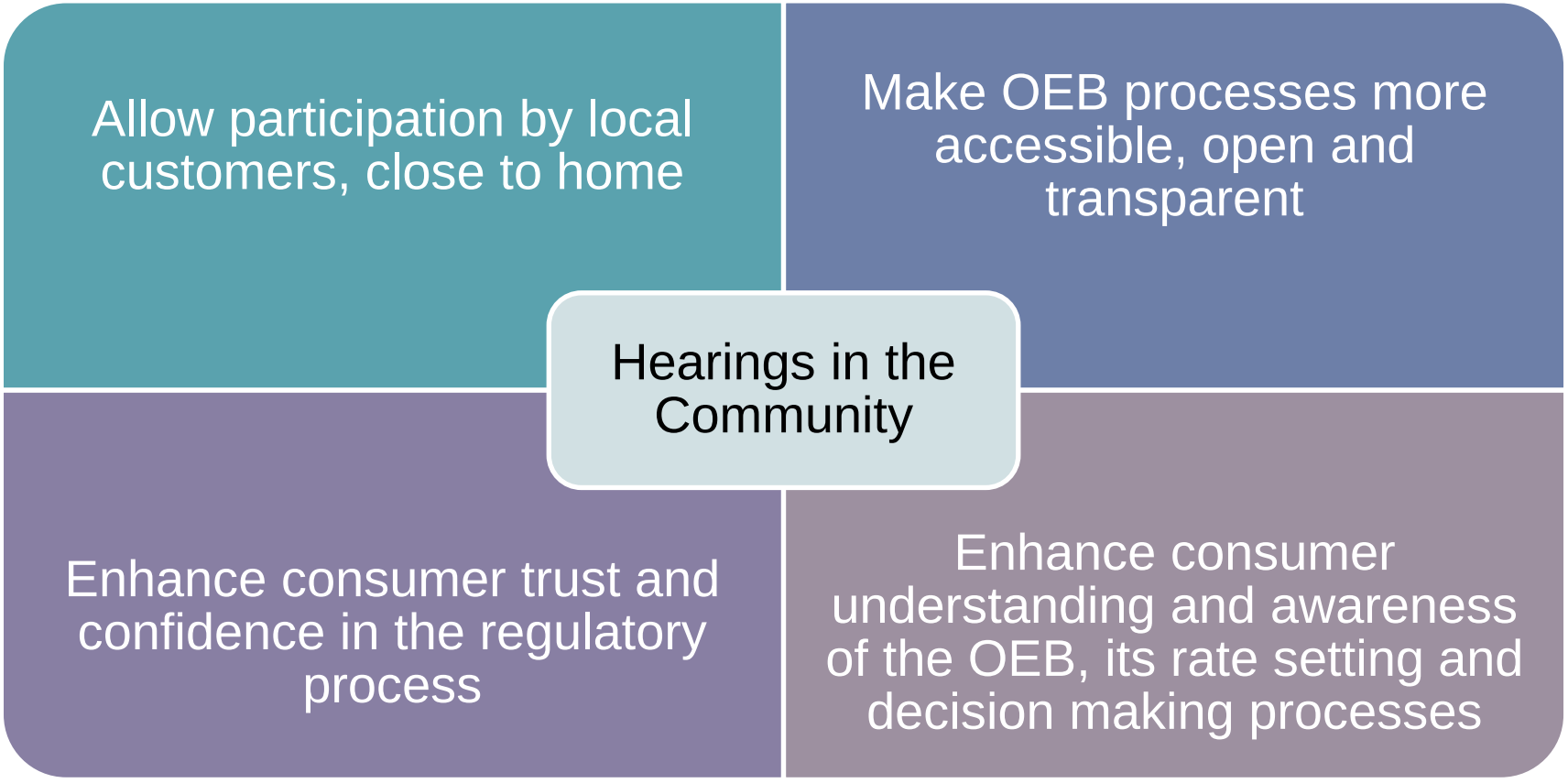
- Regional Consumer Rep
- In Your Local Community
  - Community Meeting
  - Community Hearing

Community Meetings

- OEB staff goes to local communities
- Community meetings give:
  - local customers input to OEB staff
  - the OEB a way to get customer views and opinions into a hearing
- Community meetings are:
  - local - held in the utility applicant's service area
  - open house format - relaxed way for customers to engage
  - held after a utility files their application but before the hearing
  - broadly advertised

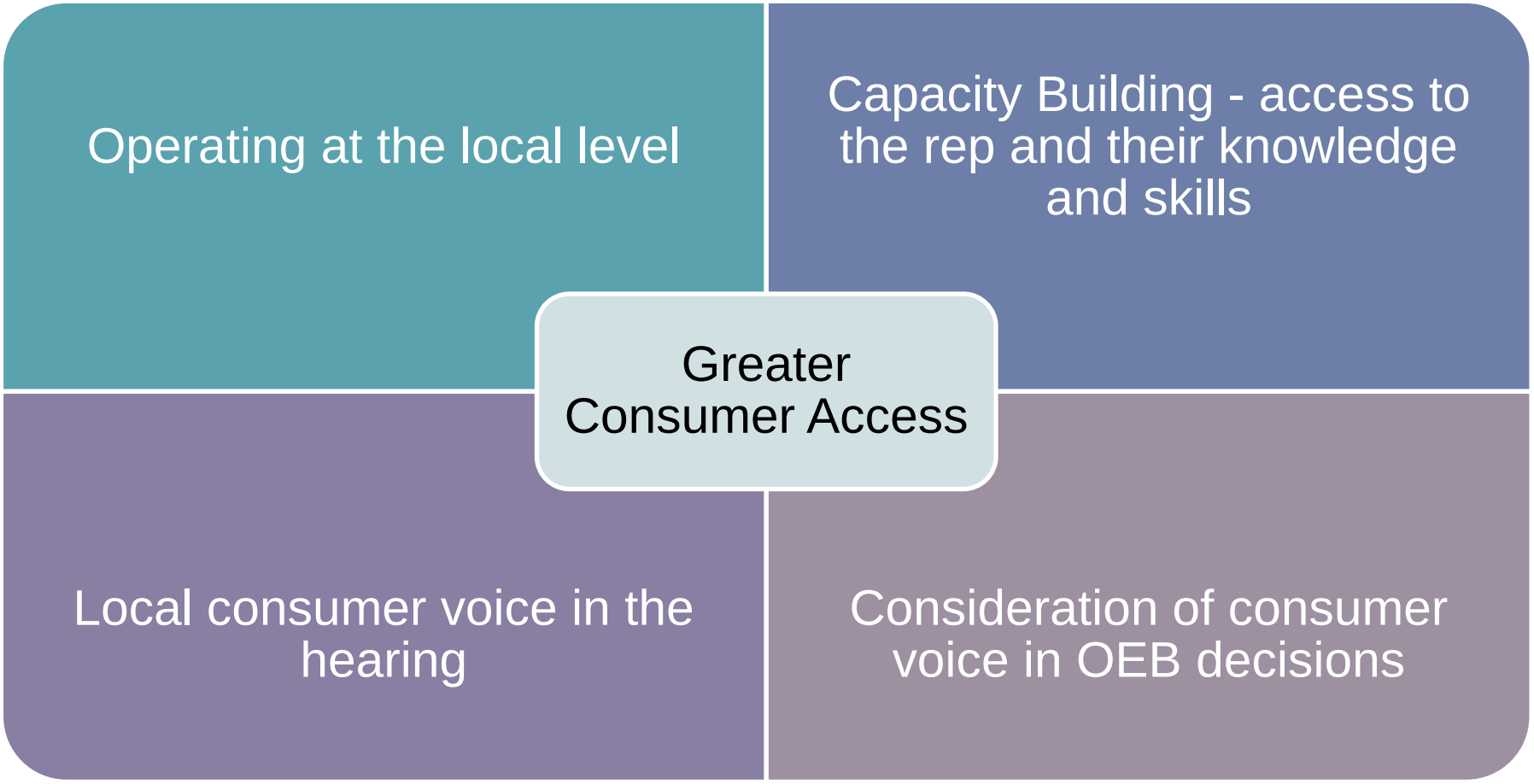
Hearings in the Community

- In 2016, the OEB will hold larger hearings (in whole or part) in a local community impacted by a utility application



Regional Consumer Representatives

Starting in 2017, OEB will pilot the use of local community-based representatives to gather information from and advocate on behalf of local customers during the hearing



Questions

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Filing Requirements – Chapters 1 and 2 – 2016 Update

Summary of Key Changes

Martin Davies

July 28, 2016

Chapter 1

- Chapter 1 is general guidance on the filing of all types of electricity distributor applications

- No substantive changes proposed

Chapter 2 – Key Changes

- Preambles Removed or Condensed
- Re-alignment of Existing Sections
- Updates for Policy Changes
- Key Changes to Existing Sections
- New Sections Added

Preambles Removed or Condensed

- Previous version of FRs had significant amount of RRFE context
  - Useful for initial years following commencement of RRFE
  - Not required to the same level of detail going forward
  - Certain RRFE context retained for evidentiary portions of the FRs
  - No new information on Consumer Engagement Framework

Re-Alignment of Existing Sections

- Filing Requirement structure:
  - Introduction
  - Exhibit 1
  - Exhibit 2, etc
- Introduction renamed to “General Requirements”
- Certain sections moved from exhibits to General Requirements (e.g. materiality thresholds) and others moved from General Requirements to exhibits (e.g. performance measurement).
- Exhibit 1 re-aligned for more logical flow
  - Administration section now comes first (includes ToC)
  - New structure to Executive and Application Summaries

Updates for Policy Changes (1)

- Funding for “eligible investments” (2.0.9)
  - No change – Footnote added acknowledging Bill 218
- Load and Revenue Forecasts (2.3.1)
  - Any impacts the load transfer policy issued on March 30, 2016 will have on customer numbers in 2017 should be noted
- Pensions and Other Post-Employment Benefits (OPEBs) Consultation (2.4.3.1)
  - Pending completion of this consultation, a new Appendix 2-KA has been developed to provide the necessary information on the accounting method used by the applicant.
- Lost Revenue Adjustment Mechanism (2.4.6.1)
  - The LRAMVA Report issued on May 19, 2016 outlined changes to the LRAMVA calculation, particularly related to lost revenues from peak demand savings

Updates for Policy Changes (2)

- Bill Impact Information (2.8.11)
  - Report of April 14, 2016 determined that the typical residential consumption to be used should now be 750 kWh, rather than 800 kWh

Key Changes to Existing Sections (1)

- Additions to certain sections to support criteria assessment
  - Performance Measurement (2.1.7)
    - Applicant must provide a forecast of its efficiency assessment using the PEG forecasting model for the test year for the purposes of providing the OEB with a directional indicator of efficiency
  - Operating Expenses (2.4)
    - Appendix 2-L augmented to include a breakout of OM&A per customer into Operations and Maintenance per customer and Administration expense per customer.
- Workforce Planning and Employee Compensation (2.4.3.1)
  - Distributors must discuss the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation
- Certain sections removed entirely
  - Governance
  - Smart Metering Entity Charge
  - Harmonised Sales Tax
  - PILs variance account
- Administration(2.1.3)
  - New Appendix 2-A required which must list all specific approvals requested and relevant sections of the legislation
  - New statement confirming that the distributor will have implemented monthly billing for all customers by December 31, 2016

Key Additions to Existing Sections (2)

- Capital Expenditures(2.2.2)
  - Three additions – details to be provided for:
    - Any capital contributions made or forecast to be made to a transmitter with respect to a connection and cost recovery agreement
    - Efficiencies Realized Due to Deployment of Smart Meters and Related Technologies
    - Rate-Funded Activities to Defer Distribution Infrastructure
- Load and Revenue Forecasts (2.3.2)
  - New Appendix 2-IB to summarize load forecast and variance analysis (replaced text in FRs)
- LRAM Variance Account (LRAMVA)(2.4.6.2)
  - New workform has been created to provide clearer information from distributors seeking to dispose their LRAMVA

Key Additions to Existing Sections (3)

- Revenue Requirement Work Form (2.6.1)
  - Has been expanded to include summaries of customer/connection, load forecast, cost allocation, rate design and revenue reconciliation with elimination of related appendices and ability to calculate base distribution rates
- Cost Allocation Study Requirements (2.7.1)
  - Distributors to make best efforts to update all classes' load profiles using the most recent data, particularly from smart and/or interval meters
  - Standby rates section has been updated to reflect OEB policy statement in which the intention was stated to remove the standby charge when the new rate policy is implemented for commercial customers

New Sections Added

- Late Filing of Cost of Service Application(2.0.5)
  - Requires that late applications filed after the commencement of the rate year for which the application is intended to set rates should be converted to the following rate year

- Distributor Consolidation(2.1.9)
  - Distributor that has acquired or amalgamated with another distributor or distributors must identify any incentives that formed part of the acquisition or amalgamation transaction if the incentives represent costs that are being proposed to remain or enter revenue requirement

Questions?

Ontario Energy Board
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Orientation Session
Electricity Distributors' Rebasing for 2017 Rates

Consolidated Distribution System Plans

Keys to Success

Jane Scott
July 28, 2016

Today's Presentation

1. Introduction and Background
2. Distribution System Plan Evaluation
3. Existing and Future States of the LDC
4. Proposed Investment Plans and Investment Categories
5. Things that have Gone Well
6. Opportunities for Improvements

Introduction and Background

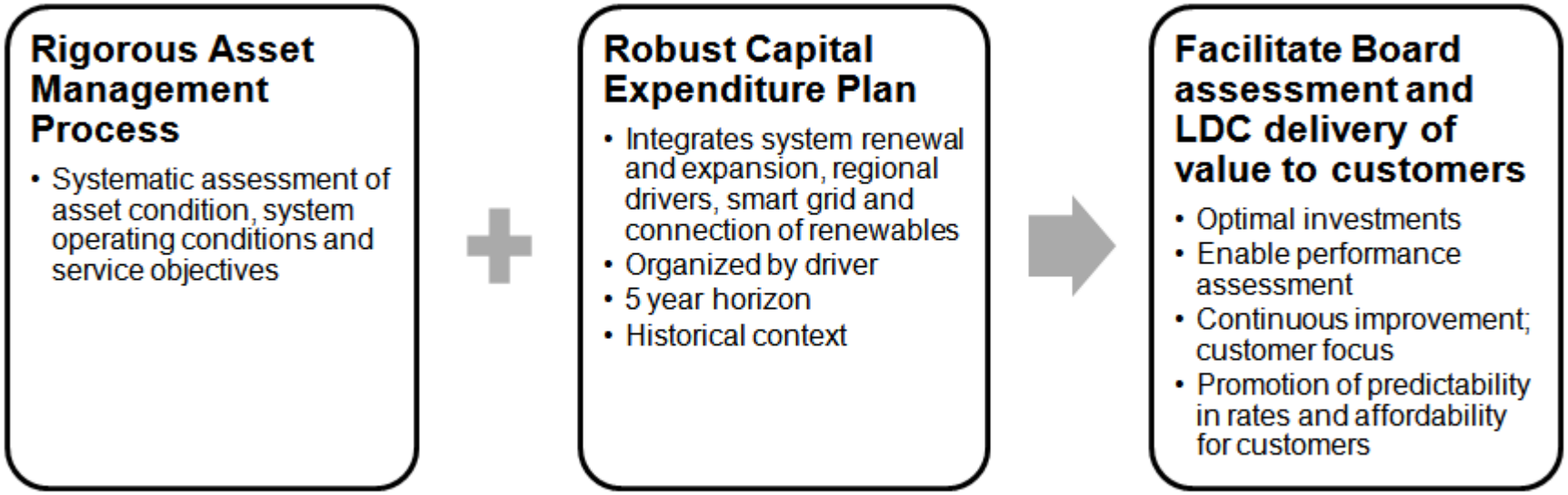
- Distribution System Plans (DSPs) are a key component of the OEB's Renewed Regulatory Framework for Electricity Distributors (RRFE) Report of October 18, 2012.
- In that report it was stated that:
  - LDCs are required to file five year capital plans to support their rate applications and the OEB needs evidence that a distributor's planning and prioritization process is sufficiently rigorous to support and justify its proposed capital budget.
  - Capital plans need to be properly paced and prioritized and due regard must be given to Smart Grid and Regional Planning issues
  - Annual performance monitoring and reporting is required to measure success against desired outcomes, especially the four OEB newly established outcomes
  - Consolidated and stand alone

Introduction and Background (cont'd)

- The OEB's RRF Report stated that the DSPs should utilize an asset management and structured investment planning approach
- Asset management is the management of risk associated with asset ownership and operation over the life of the asset.
- In carrying out their asset management and investment planning LDCs should:
  - Consider current and future customer needs
  - Consider regional planning requirements along with distributed generation, smart grid and CDM impacts
  - Ensure that all investments are planned together in an integrated manner

Integrated System Planning

- More standardized approach to distribution planning is core to the OEB's assessment of delivery of the RRFE's goals



Context supporting the DSP

- Application presents the opportunity to describe:
  - The business conditions in which you operate
  - The challenges you face
  - The targets you are working toward and why
  - The results you are prepared to report against beyond those required in the scorecard
- Also an opportunity to assess results:
  - Report on assessment of past planning activity
  - Explain how results affected the DSP
  - The results your DSP will provide over the rate term – quantified where possible

Distribution System Plan Evaluation

The DSPs, which are required to cover a five year period, will be evaluated against the following performance outcomes:

- Customer focus (Were customer preferences solicited and considered and what is the customer “value proposition”?)
- Operational Effectiveness (Have reliability and quality been considered and have cost improvements been pursued?)
- Public Policy Responsiveness (Have the renewable generation, support for low income customers and CDM requirements been met?)
- Financial Performance (Is the financial performance appropriate and is it sustainable?)
- Any other LDC specific outcomes as appropriate

Distribution System Plan Evaluation

In assessing the distribution system plan, the OEB will consider:

- Is the plan consolidated ?
- Does the plan provide a direct and clear alignment of the various components, explicitly showing how the process steps lead to an optimized plan and a corresponding capital investment program?
- How has the plan addressed the information and preferences gathered from the company's customer engagement work?
- Does the plan deliver quantifiable benefits for customers?
- Has the company controlled costs through optimization, prioritization and pacing?

Distributors should expect their plans to be examined thoroughly and to be subject to challenge. This testing will be done by the OEB's staff and experts, as well as by external participants in the process.

Distribution System Plan Evaluation

In reviewing proposed capital plans, the OEB will assess:

- whether and how conservation has been considered as an alternative to infrastructure investment
- whether and how conservation has influenced the prioritization and pacing of investment plans
- whether and how regional planning has been effectively integrated into the distribution system plan, e.g. is there a plan, if so is the DSP consistent with the plan, if not, what is the timing and would it affect the DSP?
- whether and how smart grid has been effectively integrated into the distribution system plan
- whether and how distributors have addressed the specific requirements outlined in the OEB's Supplemental Report on Smart Grid

Existing Distribution Facilities (Current State)

- A description of the existing distribution system should be provided including key characteristics and any analysis along with the principal indices used for monitoring this system as well as any cost efficiency programs that are in place
- A description of the existing Asset Registry along with the current Asset Condition Assessment Report should be provided
- A description of the more significant current and projected change drivers should be provided

Proposed Distribution Facilities (Future State)

- The key strategic imperatives of the organization should be provided
- A description of how the strategic plan or the key distribution related imperatives is(are) proposed to be operationalized should be provided
- The performance targets and indices proposed to determine performance achievement should be provided (e.g. reliability, customer service, cost savings)
- A description of the Investment Planning and Prioritization tools should be provided along with an explanation of how capital and OM & A spending is optimized as a totalized expenditure

Investment Categories

Generally the “Wires” investment can be grouped into one of four categories:

- System Access (Customer connections or municipal modifications)
- System Renewal (Refurbishment of aging equipment)
- System Service (Improvements, upgrades, modifications to improve efficiency or flexibility)
- General Plant (Non power system assets)

Proposed Investment Program

- The investment requirements should be detailed over a five year period and details should be provided as to:
  - how these investments meet the goals and the targets that the applicant has set out;
  - what alternative investments were considered and why were they rejected;
  - why the pacing that has been chosen is appropriate (and why faster/slower has been rejected);
  - In what areas are capital/O &M trade-offs proposed and how will they be undertaken; and
  - how these investments specifically meet the performance levels for the four OEB established outcomes (and any other selected outcomes).
- The investment requirements should also be broken down into the four investment categories and the projected OM & A spending should also be provided with an associated breakdown.

Material Investments Evaluation

The following criteria are listed for the evaluation of material projects:

1. Efficiency, Customer Value, Reliability
2. Safety
3. Cyber-security, Privacy
4. Co-ordination, Interoperability
5. Economic Development
6. Environmental Benefits.

Things that have Gone Well

- All applicants have filed a DSP, recognizing that some were further along in the asset management process than others
- Most LDCs are utilizing some kind of asset registry
- A number of LDCs have made a good start on a DSP customer engagement process
- Many LDCs have linked the high level strategic improvements to the DSP operational goals.
- Many LDCs utilize a systematic and structured approach to investment planning
- Some LDCs are doing extensive condition assessments through testing and inspections

Opportunities for Improvements

- Greater inclusion of OM&A spending levels and trends should be considered in the overall expenditure optimization. “It is not clear that the LDC has considered the capital / O&M tradeoffs because this process is not described in the DSP and no information has been provided at this time to indicate the expected effect of the proposed investments on O&M.”
- There could be further efforts to rank new discretionary investments. “Project Prioritization Model is not specific, no clear indication of how projects would be selected in the event that not all capital is approved.”
- There should be more performance level tracking to determine if the proposed investments result in commensurate improvements in performance or efficiency “LDC mentions some metrics it is considering for evaluating its performance in executing the DSP, however, these are not finalized and historical information for comparison is not provided.”

Opportunities for Improvements (cont'd)

- DSP must provide a clear link between the asset condition and asset management to the planned capital expenditures/Assets proposed for replacement are not aligned with the recent results of the LDC's asset condition assessments
- Reliability and outage trends do not support the capital investment levels proposed in the application
- The Customer Engagement process could be more robust with more examples of what was considered/rejected and why. Timing of customer engagement is important, feedback from customers needs to be reflected in application. "LDC may have treated customer engagement as a "box to be ticked" rather than a central element in planning."
- Generally project benefits are not quantified/Justification of projects doesn't seem to be tied to quantification of benefits

Opportunities for Improvements (cont'd)

- "Linkage between load growth in load forecast and used for project justification not provided"
- Clearer examples of the investment selection algorithm(s) should be put forward and if it is risk based, examples of how the probability/consequence of failure costs are set off against the proposed investments should be provided "more fulsome description of the asset management process should be provided"
- System Renewal is based on age relative to "Typical Useful Life" and "Condition" with little back up support. "The OEB shares the concerns of the parties that the age of the assets may be too heavily weighted in the determination of end of useful life."
- "Decision making based on mix of objective data analysis mixed with subjective gut feel decision making"

Thank You

QUESTIONS

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Orientation Session
Electricity Distributors Rebasing for 2017 Rates

Load Forecasting

Keith C. Ritchie

July 28, 2016

Table of Contents

- Role of Load Forecast in Rate-setting
- Forecasting Customers and Demand
- Load Forecast Variance Analysis: Appendices 2-IA and 2-IB
- CDM and Load Forecasting: LRAMVA and the CDM Adjustment to the Load Forecast

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 or kVA)
- Used in several ways:
  - Allocators for recovery of costs from different customer classes
  - Billing determinants for determining fixed and variable rates and for other rate riders
  - Sales volumes (customers, kWh, kW) factors into revenue sufficiency/deficiency
- Load forecast important for capital planning for system reliability and capacity
  - Different purposes and values between system capacity planning and for rate setting (i.e., extreme values and probability of failure versus expected weather-normalized load), but models are related.

Forecasting Number of Customers / Connections

- 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 made for unique growth patterns in individual classes, movement between customer classes, or changes in customer class definitions

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
- Differing Modelling approaches
  - Normalized Annualized Consumption
  - Regression
  - Others
- Beginning in 2013 CoS, several utilities used class-specific models for: Residential, GS < 50 kW, GS > 50 kW
  - Other classes forecasted using 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?		
e.g., August 2003 Blackout, 2013 Ice Storm	Binary flag variables for blackout or reduced consumption due to storm damage. As needed – but should be explainable as linking to identifiable and material phenomena	-ve

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?
  - e.g., +ve CDM, -ve Income, -ve HDD or CDD are unintuitive
- Use of binary variables?
  - Binary variables can eliminate impact of outlier data points …
  - … but, overused, may hide other issues with model specifications
- 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

2.3.2 – Load Forecast Variance Analysis

- Check on the accuracy of the distributor's past load forecasts
- Variance analysis for customers/connections, kWh, kW, revenues, kWh per customer or connection for 5 historical years, and Bridge and Test Years:
  - Historical OEB-Approved vs. historical actuals
  - Historical OEB-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-IB must be filled out
- Sheet 9 of the RRWF must also be filled out with the test year load forecast (Initial Application, during processing, and per Board Decision)

Conservation and Demand Management – Relationship with Load Forecasting

- Since 2006, distributors have been delivering CDM programs
  - Distributor, OEB-approved or IESO programs
  - Four-year CDM framework (2011-2014)
  - Current six-year CDM framework (2015-2020)
- Successful CDM reduces load relative to historical levels and relative to customer growth, and should have persistence into future periods.
- CDM results reported by IESO
  - Reported kWh 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
      - Full-year impact for persistence in subsequent years
- Utility should account for impacts of CDM programs in all years up to the test year
  - Issue is 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 year forecasts

LRAMVA

- LRAMVA
  - New CDM Guidelines issued April 2012
  - In December 2014, the OEB confirmed the continued use of the LRAMVA for the 2015 to 2020 CDM Framework
  - 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 IESO, or a third party in accordance with IESO guidelines
- For 2017, the OEB must approve:
  - 2017 test year load forecast, including the persistence of historical programs up to 2015, and expected 2016 and 2017 CDM programs impacts on the 2017 consumption and demand
  - Corresponding amounts used for establishing the 2017 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 IESO-reported numbers for persistence of CDM programs on the test year load forecast
- CDM adjustment on load forecast must recognize the following:
  - "Real" 2017 CDM program impact on 2017 demand is less than annualized (½ year rule used as default)
  - Historical CDM program impacts are captured, in some form, in historical actuals up to 2015
  - CDM adjustment is the additional impact beyond what is in the base forecast and reflecting that first year CDM program impacts are not full annualized impact as reported by the IESO
- Appendix 2-I updated for 2017 Filers
  - Only 2015-2020 table to be filled out
- New LRAMVA model to be completed
  - Relates to Account 1568 entries and disposition

Questions?

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Orientation Session – 2017 Rates

Cost Allocation and Rate Design

Stephen Vetsis, Advisor

July 28, 2016

Agenda

- Cost Allocation
  - Policy Review (changes since 2013)
  - Policy impacts on filings
  - Cost Allocation Filings
    - Cost Allocation Model (changes)
      - V3 to V3.4
- Rate Design
  - Transition to fully fixed rates for residential class
  - Implementation details
  - Exceptions and approaches to mitigation

Cost Allocation Policy: Your Last Filing (2013)

- OEB had recently issued Report of the Board: “Review of Electricity Distribution Cost Allocation Policy”, EB-2010-0219, March 31, 2011

- Cost Allocation Model was updated to implement changes required:
  - MicroFIT administrative costs worksheet
  - Miscellaneous Revenues allocated in proportion as corresponding cost drivers
  - Distributor-specific weighting factors for Services and Billing
  - Treatment of transformer ownership allowance reflected in CA model
  - Revenue to Cost Ratio ranges narrowed (GS 50-4,999, Sentinel Lighting)

- July 16, 2013 memo addressed allocation by host to embedded distributors
  - If host distributor has a separate embedded class, continue to show a separate line in CA model and Appendix 2-P.
  - If host distributor bills embedded distributors in GS class, must complete appendix 2-Q. Embedded distributors should be included in data inputs for GS class: customer count, load forecast, revenue, etc.

- Deferred for study and future development:
  - Unmetered Loads (EB-2012-0383; Board report Dec. 2013)
  - Load Displacement Generation (EB-2013-0004)

CA Policy Review: Unmetered Loads (EB-2012-0383)

Board Report 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
- "Conditions of Service 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 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)

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 preparation of cost allocation studies, load profile studies or other rate-related materials that may materially impact unmetered load customers.

CA Policy Review: Street Lighting (EB-2012-0383)

OEB issued letter on June 12, 2015 outlined new cost allocation policy for street lighting rate class

- Letter adopted recommendations from Navigant study, *Cost Allocation to Different Types of Street Lighting Configurations*

- Primary and Line Transformer assets to be allocated using street lighting adjustment factor (SLAF):

$$SLAF = \left(\frac{Residential\ NCP4}{\#\ of\ Residential\ Customers}\right) \Big/ \left(\frac{Street\ Light\ NCP4}{Number\ of\ Devices}\right)$$

- The “adjusted connections” is then used in place of the actual number of connections for the CCP and CCLT allocators:

$$Adjusted\ Connections = \frac{Number\ of\ Devices}{SLAF}$$

- Secondary assets will continue to use the number of connections as the allocator
- Street Lighting R/C ratio range tightened.

Load Displacement Generation (EB-2013-0004)

- OEB initiated consultation to develop standby rates for Load Displacement Generation
- In a letter dated June 11, 2015, the consultation was ended
  - OEB Rate Design Report, issued on April 2, 2015, indicated that the OEB intends to remove the standby rate when new rate design policy is implemented for commercial customers
  - Separate rate design consultation for commercial customers to be conducted

- In the interim, existing policy regarding standby rates remains unchanged:
  - Distributors may apply for standby charges on a final basis. Must be supported by evidence. Affected customers must be notified of proposed changes.

Policy Impacts on Filings

- Host distributors without a separate embedded distributor class must complete Appendix 2-Q
- Distributor should confirm adoption of code amendments to conditions of service in evidence
  - Highlight sections that have changed
- Exhibit 7 should explain how demand data in cost allocation study reflects most recent data obtained from unmetered customers in engagement prior to filing
- Distributors must provide both device and connection data in cost allocation model
  - If both inputs have not been previously provided, provide explanation how numbers were derived/confirmed in Exhibit 7
- Tighter Revenue-to-cost ratio range for street lighting class

Cost Allocation Filings: 2013-2017

- **Exhibit 7, then and now:**
  - Summary description, highlighting rebalancing (if any)
  - Similar to 2013
  - If using load profiles from Hydro One informational filing, distributor must explain why it has not updated its load profile and confirm that it intends to put plans in place to update its load profiles for its next COS application.

- **RRWF – Sheet 11**
  - Provides summary tables for results of cost allocation study and proposed changes/rebalancing
  - Used to be Appendix 2-P, no change in required information

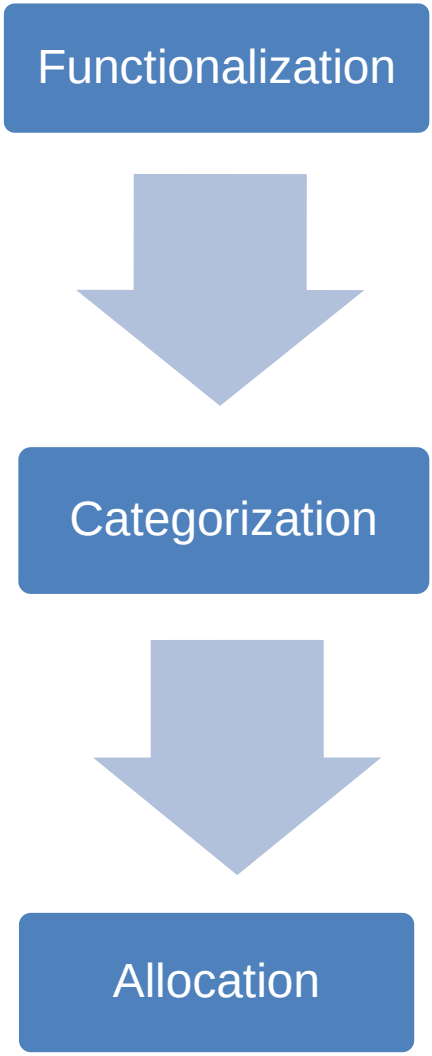
- **Appendix 2-Q**
  - Provides sharper focus on embedded distributor(s) than CA Model
    - Information required of host distributor, if no separate class of embedded distributor(s)

- **CA Model, then and now**
  - Similar to V3 (2013)
  - 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 (RRWF – Sheet 11)

- Applicant must complete Sheet 11 of RRWF:
  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 3.0

- Same as version 2.0 but included formulas for recovery of PP&E balance

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.

CA Model: versions 3.4 and 3.3 vs 3.2

Version 3.3

- Changes made reflect new OEB policy for cost allocation for street lighting class
  - Street Lighting Adjustment Factor (SLAF) is calculated on Sheet I6.2
    - Cells J22 and J23 divide the number of devices by the SLAF for the allocation of primary and line transformer assets
  - Sheet E3, formula for CCP and CCLT allocator has been updated to take the values calculated on J22 and J23 for the street light class
- Sheet I2: Residential, GS < 50 and Street Light classes are locked
  - To ensure inputs are always in the same place for calculating SLAF
- Distributor must now include both device and connection data
  - If prior cost allocation study did not include both values, distributor may wish to provide details how the number of devices and connections were derived/verified

Version 3.4

- Instructions sheet updated
  - Instructions corrected and edited.
  - Removal of instructions related to older versions of models.

Intangible Asset Accounts

USoA Account		Equivalent Account in Cost Allocation Model	
1609	Capital Contributions Paid	1810*	Leasehold Improvements
1611	Computer Software	1925	Computer Software
1612	Land Rights	1806	Land Rights

* or other unused 1800 series account with DCP/TCP allocator (e.g. 1825)

Rate Design: Background

- OEB Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410) was issued on April 2, 2015.
  - All distributors would transition to a fully fixed charge for the residential class using a standard method.
  - Transition over 4 year period in equal increments.
  - Exceptions to standard method to be considered where:
    1. Fixed charge increases by more than $4.
    2. Where the combined impact with other changes in a rate application would lead to “unusual rate impacts.”

- OEB issued letter on July 16, 2015, providing implementation details for new rate design
  - Details also reflected in Filing Requirements and Filing Modules.

- Distributors completed first stage of transition in their 2016 rate applications.

Rate Design Filing Details

- Method for calculation of fixed rate is now included in RRWF (sheet 12)
  - For COS: Calculation based on billing determinants from proposed load forecast.
- All new distribution-specific riders should be fixed-only for residential class
  - E.g.: Group 2 DVAs, disposition of Account 1575/1576
  - Rate riders arising from variances in pass-through charges that are part of delivery line (such as wholesale market service rate) should continue to be collected and disposed on variable basis
  - Existing rate riders that have not expired should remain unchanged.
- No expected changes to method for LRAM/LRAMVA calculations.
- Identical treatment must be applied for any seasonal residential classes.
- Expect that most distributors will maintain transition period approved in 2016 rate application, as the default.
- Filing should show results of both tests for mitigation.
  1. Rate design change causes fixed rate to increase by more than $4.
  2. Total bill impact for a customer at the lowest 10th percentile of consumption is greater than 10%.

Approach to Mitigation

If either of two tests for mitigation is met, distributor should propose mitigation for the residential class.

- **First scenario :** if the rate design change itself causes the fixed charge to increase by more than $4 in a particular rate year.

- **Mitigation Approach**: Allow an extra transition year as standard form of Type 1 mitigation.
  - Require LDC to propose mitigation strategy if this does not address the problem.
  - One extra year should address most distributors
  - Allows flexibility for the few remaining exceptions

Approach to Mitigation

- **Second Scenario:** Evaluate overall bill impacts using distributor-specific low-volume customer
  - Continue to use standard 10% total bill impact test
  - Apply test to a low-volume customer at the lowest 10th percentile of consumption (to a minimum of 50 kWh)
    - Therefore, mitigation treatment will be tailored to those whose bills are likeliest to rise the most.
  - Distributor must provide details regarding how the 10th percentile was determined.

- **Mitigation Approach:** Distributor must file mitigation plan for entire residential class or indicate why such a plan is not required
  - Mitigation tool is at LDC's discretion.
  - More mitigation tools available to distributor to address this type of mitigation (e.g. disposition period for DVAs)

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2017 Cost of Service Filers – Orientation Session

Appendices and Models

Keith C. Ritchie

July 28, 2016

Evolution of the Appendices and Models

- Every year, changes to the Excel-based spreadsheets – Chapter 2 appendices, models, workforms – to align with:
  - Changes in Legislation
  - Changed or new OEB policies, handbooks, reports, guidelines or Codes
  - Changes to the Filing Requirements
    - Primarily Chapter 2 for CoS filers
  - Changes in accounting or tax rules
  - Learnings in application
  - Informational needs
- At the same time, we try to balance the need for information versus the amount of information and the work to collect and input it.

Highlight of changes to Chapter 2 Appendices

- Table of Contents links re-established
- The number of sheets reduced from 52 to 46:
  - 2-TA, 2-TB (Account 1562) deleted
  - 2-Cx (Depreciation) schedules revamped, reducing several sheets
  - 2-P (Cost Allocation), 2-PA (Residential Rate Design), 2-V (Revenue Reconciliation) moved to RRWF
- Additions:
  - 2-A List of Requested Approvals
  - 2-IA (Instructions on Load Forecasting Analysis)
  - 2-IB is an expanded Load Forecasting summary and analysis that replaces the previous 2-IA
  - 2-KA – Pensions and OPEBs – replaces generic IR
- 2-L (OM&A per customer and per FTE) has been expanded:
  - Separately disaggregate O&M and Admin expenses
- Most other sheets have had minor formatting and other changes
  - Improve use, inputs and presentation but do not materially affect calculations

Changes to Other Models

- Cost Allocation
  - Separate Presentation from Stephen
- DVA (Continuity Schedule) Workform
  - Covered under Accounting
- LRAMVA Workform
  - Separate presentation from Josh
- PILs
  - Updated for 2017 tax rates and changes
- RTSR
  - Updated for 2016 UTR changes
- Tariff Schedule and Bill Impacts
  - New Model, based on IRM
  - Replaces Appendices 2-Z and 2-W
- RRWF
  - New version that adds load forecast, load forecast and rate design elements.

Capital Funding Module (for ACM/ICM)

- New version issued in February 2016 following issue of Capital Funding Options Supplemental Report on January 22, 2016
- Model incorporates new Materiality Threshold calculation and is used for ACM applications in CoS applications and for ICM and ACM rate rider applications in Price Cap IR applications
- Has been used in a few 2016 COS and IRM applications
- Minor formatting changes for 2017

Tariff Schedule and Bill Impacts

- Separate model to generate the current and proposed Tariff Schedule and subsequently the Bill Impacts
- Replaces Appendices 2-Z and 2-W
- Follows the format in the new (2017) IRM model
  - Tariff generated first, and then bill impacts generated based on current and proposed rates.
- Excel version of the Tariff of Rates and Charges
  - While the IRM version populates the Tariff Schedule from rates already entered in or calculated in that model, the utility will have to enter its proposed tariffs. Current rates populated from rates database.

RRWF

- First major revamp of the RRWF since its introduction in early 2009
- Improves the utility of the RRWF to go beyond just calculating and verifying the revenue requirement
- Link the revenue requirement to load forecast, cost allocation and rate design information for the test year to:
  - Generate distribution rates
  - Perform revenue reconciliation with the revenue requirement

RRWF Changes

- Sheets 1-9 largely unchanged
- New table on Sheet 9 summarizes Service and Base revenue requirements and the associated sufficiency/deficiency calculations
- Added Sheets 10-13
  - Sheet 10 – Summary of customer and load forecast
  - Sheet 11 – Cost Allocation
    - Previously Appendix 2-P
  - Sheet 12 – Residential Rate Design
    - Previously Appendix 2-PA
  - Sheet 13 – Rate Design and Revenue Reconciliation
    - Previously Appendix 2-V
- Summary of Key Changes now becomes sheet 14

Why the need for change?

- The RRWF serves as a summary of the cost of service application:
  - During the processing of the application, from initial application to Decision/DRO, what are the key changes in the components of the revenue requirement
  - Allows parties to better estimate rate impacts during processing.
  - After completion of the application, it is a historical summary of the key data from the application.

Caveats

- The RRWF, even as a rate generator, does not replace the rate generator and other models that utilities use for their applications.
- It is dependent on the outputs of load forecast, cost allocation, PILs models.
- The RRWF, just like the other models you may use, are very dependent on the input data.
  - Be consistent in the data used, with respect to whether numbers are rounded or not.
  - Keep the data updated.

Questions?

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The New LRAMVA Model

Overview On How The Model Works And The Required Inputs

Josh Wasylyk

July 28, 2016

LRAMVA Work Form (NEW)

- OEB has developed a new work form for all LDCs to use when filing for disposition of Account 1568 – LRAMVA
- LRAMVA Work Form must be used by LDCs filing both IRM and COS applications
- LRAMVA Work Form builds on best practices and establishes a consistent approach for all LDCs

1) Purpose and Overview

- Use of a common tool to report information and calculate CDM impacts
- Consolidates information that LDCs have received, and will continue to receive, from the IESO
- Allows for flexibility in changes to the form, as appropriate, to reflect the LDC's circumstances

2) Policy Changes and Requirements

LRAMVA Calculation

- There are no changes to the general approach to how LRAMVA is calculated:

(Final Net CDM Savings – Load Forecast CDM Component) x Distribution Volumetric Rate = LRAMVA

Demand Savings

- OEB held a consultation with LDCs and other expert stakeholders in early 2016 to determine any policy changes related to demand savings from CDM programs (EB-2016-0182)
- OEB determined new policy related to eligible demand savings from energy efficiency programs are specified in Table 1 the OEB Report “Updated Policy for Including Peak Demand Savings in LRAMVA Calculation”
- The new LRAMVA work form incorporates the new policy:
  - Indicates the number of months peak demand savings are applicable within from energy efficiency programs
  - Excludes demand savings from Demand Response programs

3) LRAMVA Work Form Discussion

The LRAMVA Work Form consists of the following sheets:

File Name	Description
1. LRAMVA Summary	**Table 1** provides a summary of the LRAMVA balances and carrying charges associated with the LRAMVA claim. The balances are populated from entries into other tabs throughout this work form.
2. CDM Allocation	**Tables 2, 3 and 4** include the CDM savings and allocation by rate class that were included in the load forecast.
3. Distribution Rates	**Tables 5 and 6** include a historical account of distribution rates that were used to calculate lost revenues.
4. 2011-14 LRAM	**Tables 7, 8, 9 and 10** includes 2011-2014 LRAMVA work forms. These should only be used if the LDC has not applied for approval of these amounts.
5-a. 2015 LRAM	**Table 11-a** includes a template workform for calculating 2015 lost revenues based on legacy and new programs.
6. Persistence Rates	**Tables 12 and 13** includes the 2011-2014 persistence factors and 2015-2020 persistance factors.
7. Carrying Charges	**Tables 19 and 20** includes the carrying charges related to the LRAMVA claim that is being made.

Introduction to Forecasting Using the OEB Cost Benchmarking Model

Dave Hovde
Pacific Economics Group
July 28, 2016

Overview of Forecasting Capabilities

- The Board has requested that LDCs filing for new rates provide information on cost benchmarking as a standard part of the filing.
- The Board currently uses a cost benchmarking model to determine if changes in cost performance warrant changes in the stretch factors established as part of IRM-4
- It is possible to use forecasted test year data to calculate the cost performance consistent with proposed OM&A and capital expenditures.
- Benchmarking proposed costs will provide an additional indicator of the direction of cost performance
- This work also provides LDCs with a method to demonstrate that their proposal will maintain or improve current cost performance

How Benchmarking Works

- Cost benchmarking involves calculating the following:
  - An “actual” total cost consistent with the benchmarking definition
  - A predicted total cost using forecasted business conditions
- Cost performance is defined as the difference between actual and predicted cost
- The Forecasting worksheet of the Enhanced Benchmarking model contains the relevant historical information and a place to enter forecasted values. These inputs allow for the calculation of actual and predicted cost for future years.
- Training has been provided to LDC staff on how the model works with the goal to assist their verification efforts. Some discussion of the forecasting capabilities was provided as part of this workshop.

The Benchmarking Forecast Model

- The forecast worksheet has been separated from the larger benchmarking calculations workbook
- A worksheet for LDC data inputs has been added with the following
  - 2015 historical values
  - Columns for 2017 test year data and 2016 “bridge” year data
  - Columns for 2018-2021 data for those filing custom IR proposals
- Advanced users may wish to learn more about how the model calculates actual and predicted cost.
- No action by the LDCs is required on the second and third worksheets

Release and Future Improvements

- The Forecast Model and associated instructions will be released at the same time as the latest benchmarking results and stretch factors. This is currently scheduled for August 2nd.
- This is a work in progress. Comments and suggestions are welcome as revisions to these documents are expected.

Data Requirements

- Eleven data items are required:
  - OM&A expenses as adjusted
  - Plant additions and HV plant additions
  - Customers, Delivery Volumes, and Peak Demand
  - Circuit-km of line
  - Ten-year customer growth
  - Rate of return, labor price, and economy-wide inflation forecasts
- There are three worksheets that comprise the Benchmark Forecast Model. The next 3 slides provide a quick overview of each.

Worksheet 1: Model Inputs

- The 11 required data series are numbered on this worksheet
- For those with standard filings, data need only be provided up to the 2017 test year
- For those proposing custom IR, the model has the capability to go out to 2021
- The OM&A calculation is more involved and two options are offered
  - Method 1: The LDC calculates the total OM&A of accounts used for benchmarking, HV OM&A, and the LV adjustment and enters the values. Support for these calculations shall be provided.
  - Method 2: The applicable OM&A account data are entered and the LV adjustment data are provided. The spreadsheet calculates OM&A cost.

Worksheet 2: Benchmarking Calculations

- These calculations are taken from the Enhanced Benchmarking Spreadsheet Model.
- The information provided on the Model Inputs worksheet feed into this worksheet. No LDC action is required.
- Additional information on these calculations are included as part of the Spreadsheet Model. A users guide is available for those that wish to learn more about how the model works.
- Anyone responsible for completing the Benchmarking Forecast that did not attend the training session last year may find it beneficial to speak with a colleague that did. The materials for this session are posted on the OEB website.

Worksheet 3: Results

- The results worksheet takes the benchmarking results from the calculations worksheet and presents them in a cleaner format
- It presents the actual and predicted cost as calculated by the model
- The method the model uses to calculate percentage differences uses logarithms. In most cases these will be similar to the familiar arithmetic method.
- The first line of cohort information refers to where an individual year's performance fits within the Board-established categories used to determine stretch factors.
- The second line refers to the three-year average performance used to assign stretch factors
- No LDC action is required on this worksheet

OM&A Expense Calculations

- The OM&A cost calculation is specific to benchmarking
- The included accounts are listed on the worksheet
- Some costs are not included in the total or explicitly excluded:
  - Bad Debt is not included
  - Generation or Transmission OM&A accounts are not included
  - High voltage costs classified as distribution are excluded (the HV adjustment)
- Some costs associated with LV service from Hydro One Networks are added
  - 100% of the following are added
    - LVDS Low Facility Charge
    - Specific ST Lines Facility Charge
    - Meter Charge
  - 45% of HVDS Low Facility Charge is added
- These steps were taken to improve comparability among LDCs

Capital Cost Calculations

- The capital cost calculations are complex, but only data on plant additions are required from the LDC to update the model
- Depreciation is standardized across LDCs
- Plant additions are separated into quantity and price each year.
- A “perpetual inventory” method is used to track the quantity of plant added and removed each year.
- A capital price is multiplied by the capital quantity to get a measure of capital cost
- This capital cost will not be the same as calculated using traditional cost of service methods

Caveats

- The prediction the model produces must be compared to the LDC cost calculated using the same methodology. The spreadsheet does this calculation.
- The model is designed to produce a valid comparison between actual and predicted cost for a given LDC for a given year. Comparisons of predicted cost to other data such as the historic cost of other LDCs may not be valid.
- A direct comparison of an LDC revenue requirement to the model prediction would not be valid. Reasons for this include:
  - Certain costs are excluded from the benchmarking cost calculations
  - The capital cost used for benchmarking purposes is different than that used for ratemaking
    - Taxes are excluded
    - Depreciation rates are standardized and are not straight-line
    - The concept of rate base is not used in the calculations

Additional Resources

- The 2014 Benchmarking Update Report
- The 2014 Spreadsheet Model
- Training Session Materials
- The Users Guide for the Benchmarking Model
- On August 2, the 2015 version of the Benchmarking Update report should be available on the same page as the 2014 version of the document and the Spreadsheet Model will be posted on the 2017 EDR webpage
- It may be necessary to right-click the above links and select “open hyperlink” to access the file on the OEB website

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

Orientation Session
Electricity Distributors Rebasing for 2017 Rates

Accounting Matters

Review of filing requirements and Chapter 2 appendices

Raj Sabharwal and Donna Kwan
July 28, 2016

Agenda

1. Accounting Standards
2. Capitalization and Depreciation Policy Changes
3. Adoption of IFRS
4. Chapter 2 Appendices
5. Changes to DVA Continuity Schedule
6. CBR
7. Questions

Accounting Standards

- Utilities must have converted to International Financial Reporting Standards (IFRS) by January 1, 2015.
- Accounting Standards used in rate applications include:
  - IFRS as set out in Part I of the CPA Canada Handbook
- The OEB may permit utilities to use US GAAP and Accounting Standards for Private Enterprises. Utilities must request prior approval from the OEB.
- Filing Requirements and Chapter 2 Appendices are structured for applicants that adopted IFRS January 1, 2015.

Key References

Key References for interpreting Filing Requirements

- Report of the Board: Transition to IFRS (EB-2008-0408), July 28, 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 OEB Letter – Changes to depreciation expense and capitalization policies
- June 25, 2013 OEB Letter – Accounting policy changes for Accounts 1575 and 1576
- March 31, 2015 APH Guidance Item #s 6 -8
- July 25, 2016 Accounting Guidance on Capacity Based Recovery

Capitalization and Depreciation Policy Changes

- Per the OEB letter dated July 17, 2012, distributors remaining on CGAAP were permitted to make regulatory accounting changes for capitalization and depreciation expense policies effective January 1, 2012. These changes were mandatory by January 1, 2013.

- These accounting changes should be consistent with the OEB'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)

- Many 2017 applicants last rebased in 2013, when they updated their capitalization and depreciation policies.

Capitalization and Depreciation Policy Changes (con't.)

Capitalization Policy

- File capitalization policy, including changes to that policy since the last rebasing application.
  - Indicate whether the applicant updated capitalization policies required by the OEB in the current or previous application.
  - If the capitalization policy changed since the last rebasing application, identify the changes and the cause of the changes.

Capitalization of Overhead

- Must complete Appendix 2-D regarding overhead costs on self-constructed assets.

Capitalization and Depreciation Policy Changes (con't.)

- Use OEB sponsored Kinectrics study or provide your own study to justify changes in useful lives.

- Must complete App 2-BB regarding comparison of asset service lives and Appendices 2-CA to 2-CH for depreciation expense.

- File depreciation policy or a written description of the depreciation practices followed and used in preparing the application:
  - If depreciation policy changes were made since the last rebasing application, identify the changes and explain the causes of the changes, including any changes subsequent to those made by January 1, 2013.

Adoption of IFRS

- Must identify all material changes in the adoption of MIFRS that impacts the application.
  - Impacts should be quantified and explanation and 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)
  - For applicants reflecting capitalization and depreciation policy changes in the current application, the comparison is between MIFRS and CGAAP prior to policy changes .
  - For applicants that reflected capitalization and depreciation policy changes in a prior application, the comparison is between MIFRS and CGAAP after policy changes.

Chapter 2 Appendices

- Three scenarios are generally expected:

Information to be filed in 2017 CoS Application		
	2017	Test
	2016	Bridge
	2015	Historical
	2014	Historical
	2013	Historical
	2012	Historical
	Prior	Historicals

Reflecting Accounting Policy Changes in Current Application		Reflected Accounting Policy Changes in Prior Application
1) Accounting Policy Changes in 2012 and Adopted IFRS in 2015	2) Accounting Policy Changes in 2013 and Adopted IFRS in 2015	3) Adopted IFRS in 2015
MIFRS	MIFRS	MIFRS
MIFRS	MIFRS	MIFRS
MIFRS	MIFRS	MIFRS
MIFRS and Revised CGAAP	MIFRS and Revised CGAAP	MIFRS and Revised CGAAP
Revised CGAAP	CGAAP and Revised CGAAP	Rebased under Revised CGAAP
CGAAP and Revised CGAAP	CGAAP	N/A
Rebased under CGAAP	Rebased under CGAAP	N/A

- Scenario 1 + 2 - 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
- Scenario 1-3 - For the transition year (typically 2014), the applicant may file two sets of appendices, one under Revised CGAAP and one under MIFRS. Revised CGAAP schedules are optional depending on the materiality of impacts.

Changes to Chapter 2 Appendices

- 2-C Depreciation schedules reformatted

Scenario	Appendices to Complete	Years Reflected in Appendices
Reflecting 2012 Accounting Policy Changes in Current Application	2-CA to 2-CG	2012-2017
Reflecting 2013 Accounting Policy Changes in Current Application	2-CA to 2-CF	2013-2017
Reflected Accounting Policy Changes in Prior Application	2-CH	Complete 2-CH for as many years as applicable

- Check the appropriate set of appendices in each appendix

Select the set of appendices that apply		Year Reflected in Schedule Below	Accounting Standard
☐ 2012 Set of Appendices (2-CA to 2-CG)	Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012 and has adopted IFRS for financial reporting purposes effective January 1, 2015. Assumes that the applicant is reflecting these changes in a rebasing application for the first time.	2012	Former CGAAP
☐ 2013 Set of Appendices (2-CA to 2-CF)	Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013 and has adopted IFRS for financial reporting purposes effective January 1, 2015. Assumes that the applicant is reflecting these changes in a rebasing application for the first time.	2013	Former CGAAP

Changes to the DVA Continuity Schedule

- Checkboxes in the Total Claims column of the Continuity Schedule sheet to indicate whether disposition of certain accounts are requested (e.g. Account 1595)

- Two new sub-accounts for CBR in Account 1580 WMS.
  - Account 1580 WMS must exclude CBR amounts. CBR amounts are to be recorded separately in the CBR Class A and Class B sub-accounts. Class A sub-account is not disposed.
  - Checkbox in the continuity schedule sheet to indicate whether there are Class A customers.
    - If there are no Class A customers, the 1580 sub-account for CBR Class B will be added to control Account 1580.
    - If there are Class A customers, CBR Class B sub-account rate riders are to be calculated in the application, outside the DVA continuity schedule.

Changes to DVA Continuity Schedule (con't)

- Checkbox in the Billing Determinants sheet to indicate if a Class B customer switched to Class A in 2015.
  - If this is the case, a new sheet (5a. GA_Allocation_Class A) is generated to allocate a portion of Account 1589 to former Class B customers and to calculate customer specific charges for these former Class B customers.

- Billing determinant and all the rate riders for Account 1589 GA is locked to be calculated on an energy basis (kWh), regardless of the billing determinant used for distribution rates for the particular class.

Changes to DVA Continuity Schedule (con't)

- Account 1557 is to be reported in the model on a memo basis. It is to be recovered in a manner similar to Smart Meters and should be requested for disposition upon completion of the MIST meter deployment. A prudence review and disposition should be done in the application, outside the DVA continuity schedule.

- Account 1531 is to be reported on a memo basis. Account 1532 is included in the Group 2 balance allocation used to calculate rate riders. Only include the Direct Benefits portion of Account 1532 in the DVA continuity schedule.

- LRAMVA balance and allocation is calculated in the LRAMVA model and to be inputted into the DVA continuity schedule, where the associated rate riders are calculated.

Capacity Based Recovery (previously called CBDR) - Background

- CBDR replaced DR3 under OPA. MWs under CBDR were not procured under any CDM program as defined in GA regulation. Since the IESO was creating a market mechanism under the market rules, it could recover the costs of this market program through uplift under charge types (CT). CT 1350/1351 were established and used by the IES0 since April 30, 2015.
- Recovery is allocated in the same manner as GA (i.e. recovering peak capacity-related costs tied to the contribution of various consumers in driving the need for peak-capacity resources)
- Similar to other “uplift” IESO CTs, CBDR CTs were determined to be part of WMS costs.

<u>Program Costs Recovered Through CT 1350/1351</u>

- Approximately 500 MW were procured under CBDR. Most of it expired from the CBDR program on April 30, 2016 and the balance will expire in 2018.
- In July 2015, approximately 80 MW were procured through Demand Response Pilot Programs which came into service in May 2016.
- The December 2015 DR Auction resulted in procuring 367 MWs which came into service on May 1, 2016.

Capacity Based Recovery – Key Accounting References

- OEB Accounting Guidance documents:
  - Letter dated June 4, 2015
  - Letter dated March 29, 2016
  - Accounting Guidance dated July 25, 2016

- D&O EB-2015-0294 dated November 19, 2015 – WMSR

- Supplementary D&O EB-2016-0193 dated June 16, 2016 - Provided breakdown of WMSR effective January 1, 2016:
  - WMSR of $0.0032/kWh, plus $0.0004/kWh CBDR for Class B;
  - $0.0032/kWh for Class A plus the actual CBDR costs to Class A in proportion to their PDF

Capacity Based Recovery – Accounting Guidance – Class B

- Record billings in Account 4062 Billed – WMS, Sub-account Capacity Based Recovery (CBR) Class B

Date	Rate	Account
Effective January 1, 2016	$0.0032/kWh	Account 4062 Billed - WMS
	$0.0004/kWh	Account 4062 Billed - WMS, Sub-account CBR Class B
Before January 1, 2016	N/A	No entries in Account 4062 Billed

- Record costs in Account 4708 Charges – WMS Sub-account CBR Class B
  - Record CT 1351

Capacity Based Recovery – Accounting Guidance – Class B (con't)

Record variances in Account 1580 Variance – WMS Sub-account CBR Class B

- Effective January 1, 2016 – Record the difference between:
  - amounts recorded in WMS revenues of $0.0004/kWh in Account 4062 Billed – WMS, Sub-account CBR Class B, and
  - WMS charges from IESO recorded in Account 4708 Charges – WMS, Sub-account CBR Class B

- Before January 1, 2016
  - No revenues were collected from customers for CBR prior to January 1, 2016.
  - All costs paid for CBR for Class B customers for the period from April to December 31, 2015 would have been captured in Account 1580 Variance – WMS Sub-account CBR Class B

Capacity Based Recovery – Accounting Guidance – Class A

Record billings in Account 4062 Billed – WMS, Sub-account CBR Class A

- Effective the first billing following June 16, 2016, date of the Supplementary Order:
  - Distributors must bill non-WMP Class A their share of the actual CBR charge, based on their respective Peak Demand Factor (PDF). Distributors' billings to its Class A customers should equal the total invoiced to it under CT 1350. This would result in recording zero variance in Account 1580 for Class A CBR going forward
- From January 1, 2016 to June 16, 2016:
  - Distributors have been billing Class A customers $0.0036/kWh WMSR, including $0.0004/kWh CBR since January 1, 2016.
  - Distributors are to record all 2016 consumption billed to the date of the Supplementary Order to Class A as follows: $0.0032/kWh to Account 4062 Billed – WMS and $0.0004/kWh to Account 4062 Billed – WMS Sub-account CBR Class A
- Before January 1, 2016: No entries in Account 4062 Billed - WMS, Sub-account CBR Class A

Record costs in Account 4708 Charges – WMS Sub-account CBR Class A

- Record CT 1350

Capacity Based Recovery – Accounting Guidance – Class A (con't)

Record variances in Account 1580 Variance – WMS Sub-account CBR Class A

- Effective the first billing following June 16, 2016, date of Supplementary Order:
  - No variances are recorded going forward.
- Effective January 1, 2016 to first billing following June 16, 2016– Record the difference between:
  - amounts recorded in WMS revenues of $0.0004/kWh in Account 4062 Billed – WMS, Sub-account CBR Class A, and
  - WMS charges from IESO recorded in Account 4708 Charges – WMS, Sub-account CBR Class A
- Before January 1, 2016:
  - No revenues were collected from customers for CBR prior to January 1, 2016.
  - All costs paid for CBR for Class A customers for the period from April to December 31, 2015 would have been captured in Account 1580 Variance – WMS Sub-account CBR Class A

Disposition of Variances in 2017 Applications

- If the distributor does not serve any Class A customers, it must transfer the Class B variance balance into the WMS Control account for disposition.
- If the distributor does serve Class A, it must allocate and calculate the rate riders for non-WMP Class B independent of the model
  - If the rate riders are insignificant (> 4 decimal places), transfer the amount in the Sub-account to Account 1595 for 2017. This will be disposed in a future proceeding.

Capacity Based Recovery – Accounting Guidance – Class A – Variance Treatment

- The net billing adjustment for 2015 and 2016, as calculated below is to be applied to the first available billing after the issuance of the Accounting Guidance. The total adjustment is equal to the total difference between CBR billed by the LDC and CBR charged by the IESO, plus applicable carrying charges. Once the billing adjustment is processed, the balance in the sub-account for 2015 and 2016 activity should be $0, and there will be no variances recorded in this sub-account going forward

Billing Adjustment Calculation for 2016 Variances (up to the date of Supplementary D&O)

- Calculate each Class A customer's allocation of CBR costs based on their specific portion of 2016 PDF
- Calculate the amount billed to each Class A for CBDR based on $0.0004/kWh on their consumption
- Calculate the billing adjustment as the difference between the above two amounts
- Allocate the carrying charges in Account 1580 Variance – WMS, Sub-account CBR Class A to each Class A customer on a pro rata basis of the Class A customer's specific proportion of the total PDF.

Billing Adjustment Calculation for 2015 Variances

- Calculate the billing adjustment as each Class A customer's allocation of CBR cost based on their specific PDF
- Allocate the carrying charges in Account 1580 Variance – WMS, Sub-account CBR Class A to each Class A customer on a pro rata basis of the Class A customer's specific proportion of the total PDF.

Questions?

Ratepayers' Perspective

2016 OEB's Orientation Session for Electricity Distributors Rebasing

Mark Rubenstein – Jay Shepherd Professional Corporation

Co-counsel to the School Energy Coalition

School Energy Coalition

- Who are we?
  - Coalition of seven school board organizations
  - All school boards are active members
  - 5000 schools with 2 million students
  - Spend $500 million per year on energy
  - Details posted on the Board's website
- Intervention Principles
  - Always look for the win-win solution
  - Think long term
  - "Walk softly but carry a big stick"

Electricity Ratepayer Groups

- Active ratepayer groups in LDC applications:
  - Almost Always - VECC, SEC, and Energy Probe
  - Often – AMPCO, CCC, and BOMA
  - Coming soon to a proceeding near you – Local residential/small business advocates
- Intervenor Representatives: Experienced lawyers and consultants
- Division of responsibilities

Why are we all here

- Regulation as a substitute for competition – Board as market proxy
- Each ratepayer group represents a segments of your customer population
- To review, probe, and test the reasonableness of your application
- To act as the counterweight - the Board needs other perspectives on your application

Preliminary Work

- Local newspaper, presentations to shareholders (city councils), google searches, your website, etc.
- Yearbook data for all years
- Building our own comprehensive database
- Previous applications, results, rates
- People: Who do we know?
- Customer meetings/feedback

What we hope to see in your application

- A detailed explanation of your planning process
  - Regulatory application and process, should be intertwined with your business planning process, not separate processes
  - Show us where benchmarking and comparative data enter into your planning process
  - How do you consider customer preferences and rates impacts. Show us trade-offs.
- Explain to us the challenges your LDC is facing
  - Show investigation and analysis
  - Thoughtful plan to deal with them
- Metrics and targets
- Show us the value for money of your proposed investments
  - Demonstrate why the investment is worth the added cost

How do we review an application

- Planning Documents
  - Strategic/business plan, shareholders' agreement/direction, budget guidance documents
  - Financial statements, rating agency reports
  - Distribution System Plan, Asset Condition Assessment
  - Comparative data and benchmarking
  - Rates and revenue requirement trends
  - Past applications. Have you done what you said you were going to do?
- Projects and programs
  - Business cases (Capital and OM&A)
  - Third-party reports and analysis
  - Variance analysis, expense trends, Chapter 2 Appendices
  - Benchmarking
  - Individual issues – what are they and what is your plan
- The nitty-gritty
  - Continuity schedules, depreciation, revenues (load forecast and offsets), PILS, cost allocation and rate design, D&V accounts, accounting issues

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
  - Doesn’t always account for type of service territory and customer mix
- Rate Base and Capital Spending
  - e.g. Capital Additions/depreciation ratio, unit costs trends, ACA analytics

Comparative Data

- OM&A Metrics
  - e.g. OM&A or FTE per customer, unit cost trends, compensation information
- Other Metrics
  - Components of revenue (e.g. by class)
  - Debt/equity ratio (leveraging)
  - Rates
- We have been building our own comprehensive database of comparative data using past case information and yearbook information

Consistent Issues

- RRFE
  - Outcome focus – Metrics and targets
  - Value for money
  - Benchmarking
  - Robust capital planning requirements
    - Age versus condition of assets
  - Customer Engagement – rates versus reliability
- Customer growth or decline
- Past underinvestment
- Aging workforce

Interrogatories

- “The purpose of the interrogatory process is to test the evidence before the Board” - Filing Requirements
- What we are looking for?
  - Documents referred to (or omitted), sometimes prior versions
  - Explanations
  - Missing data, steps, or confusion
  - Comparative data
  - Scenarios, “stretch testing” the assumptions and numbers
- If you do not understand the question or cannot provide the information we have asked for, pick up the phone or email

Technical Conferences/Clarification Questions

- Technical Conference
  - The Board is generally not scheduling them anymore for non-Custom IR cases
  - Usually first contact with intervenors
  - Not cross-examination, but tougher than interrogatories
  - Model technical conference is a dialogue
  - Point is to save the Board panel from wasting their time
  - Allows for parties to correct the smaller issues
- Clarification Questions
  - Provided to LDC a few days before settlement conference
  - Clarifying outstanding important issues that are required for settlement

Settlement Conferences

- Process
  - Exchange of information/dialogue
  - Intervenor caucus
  - Offers back and forth
  - Documenting any agreement
- Offers
  - Issue by issue– revenue requirement and revenue forecast usually first
  - Deficiency based packages (looking for savings)
- Settlement of other issues
  - Asset management plan and longer term issues
  - Metrics and targets
  - Cost allocation and rate design
  - Deferral and variance accounts

Settlement Conferences

- Ratepayer group point of view
  - Result by agreement vs. result by decision
  - Settlement Conference positions vs. hearing/argument positions
  - Comparative data increasingly influential
  - Uncertainty about the interpretation and application of Board policies and principles
- How to get there
  - 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
  - Opportunities and challenges
  - Impact of the RRFE

Oral Hearings

- Cross-examination
  - Bias in favour of the cross-examiner
  - Good questioners are well prepared
  - We want to challenge the assumptions in the application
  - The real testing of the evidence
- 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

The Future

- Board working on a new consumer engagement framework – *Giving Ontario Energy Consumers a Stronger Voice*
- Intervenors will not be replaced but will the tools still be in place to allow them to participate?
- Regional Consumer Representatives – piloting to begin in 2017
  - Will represent local residential and small business customers in a more direct way
  - What are the impacts of this new party in individual cases?
  - Dynamics likely to change in some way

Thank you

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