Applications Division

Major Applications
Jane Scott

- Case Managers; COS & CIR
- Subject Matter Experts e.g. DSP, Cost Allocation

Incentive Rate-setting and Regulatory Accounting
Dan Gapic

- Case Managers; IRM
- Regulatory Accountants

Supply & Infrastructure
Nancy Marconi

- Case Managers; OPG, MAADs, Leave to Construct
- Subject Matter Experts, e.g. Pole Attachments, RPP

Application Policy & Climate Change
Pascale Duguay

- Case Managers; CDM, DSM
- Subject Matter Experts, e.g. Cost of Capital, Load Forecasting,

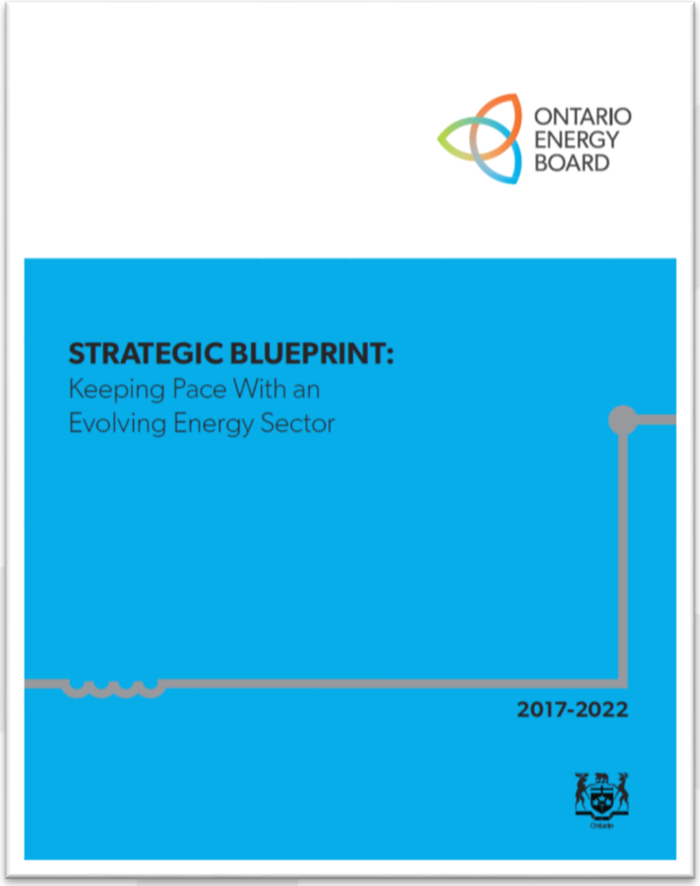
Update on OEB Major Initiatives

Cost of Service Orientation

July 19, 2018

The OEB's Strategic Blueprint

- Commits to modernize regulation to keep pace with an evolving sector
- Recognizes changes underway in the energy sector
- Refreshes the OEB's Vision, Mission, and Values
- Identifies strategic goals and objectives that will guide the OEB's work over the next five years
- Informed development of the OEB's 2018-2020 Business Plan and LTEP Implementation Plan



The OEB’s Strategic Blueprint

	Transformation & Consumer Value	Innovation & Consumer Choice	Consumer Confidence	Regulation “Fit for Purpose”
Goals	Utilities are delivering value to consumers in a changing environment	Utilities and other market participants are embracing innovation in their operations and the products they offer consumers	Consumers have confidence in the oversight of the sector and in their ability to make choices about products and services	The OEB has the resources and processes appropriate for the changing environment
Objectives	The regulatory framework incents utilities to focus on long-term value for money and least-cost solutions Regional and utility system planning reflect the continuing evolution of the sector Utility infrastructure is optimized during the shift to a low carbon economy	The regulatory framework incents and enables utilities to adopt innovative solutions The design of network rates and commodity prices support the efficient use of infrastructure and enable greater customer choice and control Our codes and rules reflect the needs of an evolving sector	Consumers understand their rights and choices Consumers are treated fairly by utilities and other service providers Consumer perspectives are welcomed, respected and addressed in all regulatory processes The benefits of innovation and sector transformation are realized by all types of consumers	We have the expertise needed to address sector evolution Our own organization and processes remain flexible and are adapted to changing needs Our work is supported by effective engagement and collaboration

The Advisory Committee on Innovation

- Convened to identify actions that a regulator can take to support and enable cost effective innovation, grid modernization, and consumer choice to help inform the OEB's regulatory policy development

- The Committee will assist the OEB by:
  - Providing insight into what, if anything, is inhibiting cost effective innovation today
  - Providing advice on potential regulatory approaches, initiatives and other actions that should be considered
  - Participating in prioritizing and sequencing of action
  - Helping scope the work needed to take action, and
  - Advising on additional opportunities that arise as work to take action is carried out

The Way Forward for Regulation

- To support the evolution of the sector, move to a regulatory framework that remunerates utilities in ways that strengthen their focus on long-term value and least-cost solutions, supports regional planning and cost-sharing arrangements among utilities, and requires utilities to reflect the impact of sector evolution in their system planning and operations
  - FY 2018/19 – Identify opportunities for and obtain advice on regulatory reform
  - FY 2019/20 – Evaluate and consult on options, ensuring a comprehensive approach. Determine preferred approach
  - FY 2020/21 – Establish and implement framework

Enabling Distributed Energy Resources

- To support the evolution of the sector, identify and develop regulatory reforms that would facilitate investment in distributed energy resources (DERs) that can benefit consumers by appropriately allocating the costs and benefits of DER investments and ensuring that diffuse benefits and multiple value streams can be appropriately recognized
  - FY 2018/19 – Identify options for and obtain advice on regulatory reform
  - FY 2019/20 – Evaluate and consult on options ensuring a comprehensive approach
  - FY 2020/21 – Determine preferred approach, establish and implement regulatory framework

“Smarter” Electricity Prices

- To provide appropriate price signals to low-volume and other Class B electricity consumers in accordance with the *Regulated Price Plan Roadmap*, develop a new methodology for the RPP
  - FY 2018/19 – Continue the implementation of pilot projects regarding the RPP. Engagement of, and data collection from small and medium-sized electricity customers. Study commodity pricing alternatives, including consideration of the recovery of global adjustment from Class B consumers
  - FY 2019/20 – Analyze the results of the RPP pilots following their conclusion. Develop pricing options
  - FY 2020/21 – Identify the preferred pricing options and associated tools; support development of any framework for implementation

Strengthening Utility Accountability

- To ensure that utilities continue to deliver value to consumers in a changing environment and support consumer confidence in the oversight of the sector, identify and implement regulatory reforms to enhance reporting and utility accountability to customers with respect to provision of service, including reliability
    - FY 2018/19 – Complete foundational work including, work to enhance reporting on reliability and a review of potential approaches for enhancing utility accountability
    - FY 2019/20 – Identify, evaluate, and consult on options for regulatory reforms
    - FY 2020/21 – Determine preferred approach and implement regulatory reforms

Review of Customer Service Rules

- Continue to review customer service rules for natural gas and electricity distributors and unit sub-meter providers. This work will help ensure that consumers are treated fairly by utilities and that our codes and rules appropriately reflect the reasonable expectations of energy consumers regarding matters such as disconnections, billing errors, and collection and reconnection fees
  - FY 2018/19 – Continue evaluation of rules and charges regarding disconnection and related activities and modify such rules and charges as appropriate. Begin evaluation of rules and charges related to management of customer accounts, billing errors and reporting requirements
  - FY 2019/20 – Conclude evaluation and modify such rules and charges as appropriate. Examine whether legislative reforms could further enhance the OEB's capacity to protect the interests of natural gas consumers
  - FY 2020/21 – Monitor the implementation of any new customer service rules and charges by electricity and natural gas distributors and unit sub-meter providers

Electricity Distributor Benchmarking

- To ensure that consumers are getting value for money, the OEB will expand its use of benchmarking to include a detailed evaluation of costs at the program (or activity) level. Enhancing monitoring of performance is expected to drive greater cost discipline among distributors, incent greater efficiency and ultimately reduce costs for consumers
  - FY 2018/19 – Develop the framework for a benchmarking model for program or activity cost measures for electricity distributors
  - FY 2019/20 – Implement program level benchmarking in the assessment of electricity distributor performance. Include program level benchmarking in rate setting processes and identify appropriate public reporting on new benchmarks.
  - FY 2020/21 – Monitor utility performance and report as appropriate to support rate setting and OEB's assessment of electricity distributors' performance in order to achieve the OEB's expectation for increasing performance and continuous improvement by the electricity distributors that are rate regulated

Making Community Meetings a Success

Rudra Mukherji
Associate Registrar

July 19, 2018

Agenda

- **Role of the Office of the Registrar in the Cost of Service application process**
- **OEB Community Meetings – Purpose & Process**
- **Making Community Meetings a Success**

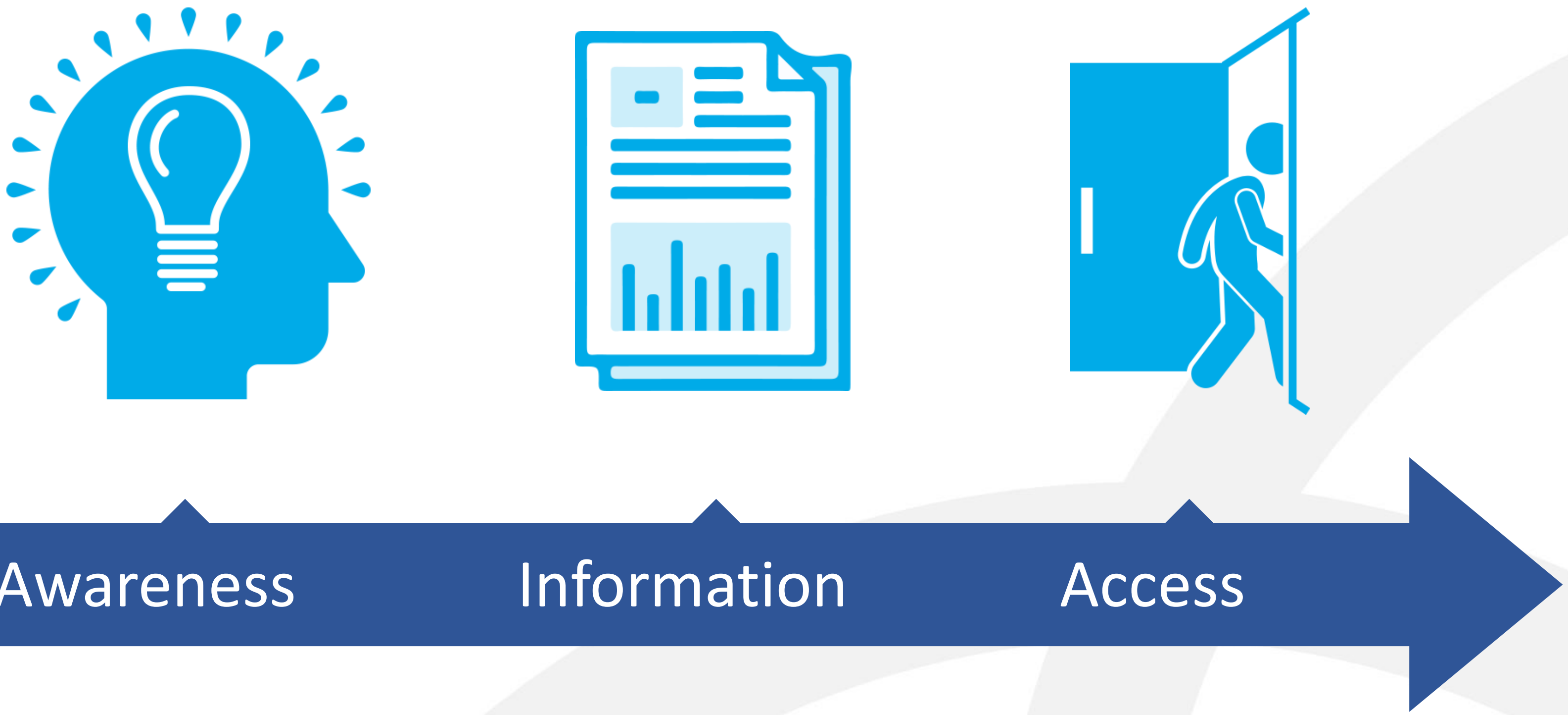
Role of the Office of the Registrar

- Delegated decision making authority for front-end procedural matters
  - ❖ Decision on Completeness
  - ❖ Notice of Hearing
  - ❖ Publication of Notice
  - ❖ Procedural Order No.1
    - ✓ Interventions and Cost Eligibility
    - ✓ Case Schedule

Consumer Engagement Framework Launch

- CEF framework was introduced May 13, 2016
- Certain framework components were tested with the OEB's Consumer Panels and the results were incorporated into the implementation of the tools
- Launch of a number of tools began in the fall of 2016 and roll out continues

Pillars of the Framework



OEB Community Meetings Purpose

Consumers can meaningfully participate

Consumer's voice is heard

OEB's regulatory process is easily understood

Decisions consider views of affected consumers

OEB Community Meetings
By the Numbers…

OEB Community Meetings By the Numbers (2016-2018)	
No. of Meetings	35
Attendance	1,211
Consumer Presentations	36
Evaluation Forms (+ survey) Returned	311
Letters of Comments Filed (at meeting)	59
News Coverage (stories)	79

OEB Community Meetings

Survey results from attendees of a 10-meeting series for one utility's rate case:

86% would attend again and refer others

73% knew meetings were hosted by OEB

70% asked questions at the meeting

66% found OEB presentation helpful

40% read Community Meeting Report

OEB Community Meetings Process

- OEB Community Meetings are:
  - An integral part of the application process
  - Led by the Office of the Registrar
  - Hosted and organized by the OEB
  - Scheduled after Notice and before Procedural Order No. 1

OEB Community Meeting Process

- Planning and execution is handled by OEB staff
- A comprehensive information package is provided to the utility
- The utility is expected to:
  - ❖ Participate in the meeting
  - ❖ Coordinate with OEB staff to determine appropriate date, venue and advertising channels
  - ❖ Have one or more executives deliver a presentation about the application
  - ❖ Prepare one or more poster boards

Making Community Meetings a Success

- Filing Requirements
  - ❖ 30-day heads-up prior to filing date
  - ❖ Information on venue, date and billing cycle
  - ❖ Plain language summary
- Advance Planning
  - ❖ Ensures timely scheduling of meetings
  - ❖ Ensures availability of the most appropriate venue
  - ❖ Allows for meeting notification in bill inserts
  - ❖ Allows OEB staff to conduct stakeholder outreach
  - ❖ Allows OEB staff to coordinate outreach
  - ❖ Allows for better planning of local advertising

Making Community Meetings a Success

- Open communication between OEB staff and Utility Communications Team
- Presentation tips…
  - ❖ Plain language presentation
  - ❖ Application focused
  - ❖ Highlight key requests and drivers impacting rates
  - ❖ Presenters should be prepared to respond to questions
  - ❖ Prepare Qs&As to effectively respond to questions

Making Community Meetings a Success

- Expect the Unexpected
  - ❖ Meeting format may have to change

- ❖ Adapt to the mood in the room

> ***"Tempers Flare Over Proposed Rate Increase"***
>
> ***"She didn't want to yell.***
>
> In fact, moments after her tearful outburst, she looked as if she regretted it. But her emotions got the better of her."

Making Community Meetings a Success

Doors open at 6:00 p.m. Meeting begins at 6:30 p.m.

- First 30 minutes give consumers time to speak with utility and OEB staff
- Utility staff should engage customers
- Be prepared to discuss billing issues/ customer complaints
- Information boards/pop-up banners should be relevant to the application
- Be prepared to speak to media as they are often in attendance

Making Community Meetings a Success

- Key Success Factors:
  - Advance planning
  - Effective outreach and advertising
  - Open communication between OEB staff and utility staff
  - Flexible and adaptable
  - Focused presentations
  - Thorough responses to consumer questions

Questions…

Chapter 1 & 2 Filing Requirements Update for 2019 Applications

Summary of Key Changes

Birgit Armstrong

July 19, 2018

Introduction

- CoS Status update
- Key Changes and Additions
- Removals and Clarifications
- Model and Appendices

Cost of Service Applications for 2019 - 1

January 1, 2019 Rates

	Expected/Filed Date	Status
Chapleau Public Utilities Corporation	Deferral Requested	Under Review
Energy Plus	27-Apr-18	Filed
Greater Sudbury Hydro Inc.	Deferral Requested	Under Review
Kitchener-Wilmot Hydro Inc.	Deferral Requested	Under Review
Oakville Hydro Electricity Distribution Inc.	Deferral Requested	Under Review

Deferral requested

Cost of Service Applications for 2019 - 2

May 1, 2019 Rates

	Expected/Filed Date	Status
Attawapiskat Power Corporation	31-Aug-18	Pending
Burlington Hydro Inc.	Deferral Requested	Under Review
Bluewater Power Distribution Corp.	Deferral Requested	Under Review
COLLUS Power Corporation*	Deferral Requested	Under Review
Fort Albany Power Corporation	31-Aug-18	Pending
Fort Frances Power Corp.	Deferral Requested	Under Review
Kashechewan Power Corporation	31-Aug-18	Pending
Lakeland Power	31-Aug-18	Pending

First Nations
Deferral Requests
*MAADs application filed

Cost of Service Applications for 2019 - 3

May 1, 2019 Rates

	Expected/Filed Date	Status
Midland Power Utility Corporation*	31-Aug-18	Pending
Niagara-on-the-Lake Inc.	31-Aug-18	Pending
Orangeville Hydro Ltd.	Deferral Requested	Under Review
Peterborough Distribution Inc.	Deferral Requested	Under Review
Veridian Connections Inc.**	Deferral Requested	Under Review

* MAADs Decision pending
** MAADs Negotiations with Whitby Hydro

Chapter 1 – Key Changes

- Addition
  - Completeness
    - A completeness checklist, based on these filing requirements, has been available to applicants for several years when completing their applications
    - Any departures by the applicant need to be identified and explained. In the case of missing information the application may be deemed incomplete
    - In addition, an application may be deemed incomplete if there are inconsistencies in the data provided
    - Following the review for completeness, OEB staff will send a letter either requesting more information or informing the applicant that the application is complete
    - The OEB will not commence its proceeding with its review until it has determined that the application is complete
- Removal
  - Confidential information
    - Removal of statement - …"that when dealing with confidential information, parties should take note of the requirement related to relevance and materiality of interrogatories outlined in Ch. 1" as it is redundant

Chapter 2 – Key Changes

- Changes and Additions
  - Addition of plain language summary requirement (s.2.1.3)
  - Expanded Customer Engagement section to include new community meeting requirement (s. 2.1.7)
  - Addition of Cost of Capital summary table in the Application Summary (s. 2.2.2.2)
  - Impact of the Fair Hydro Plan Act on calculating the Working Capital Allowance (s. 2.2.1.3)
  - Disposition of LRAMVA (s. 2.4.6.2)
  - Deferral and Variance Accounts updates (s.2.9)
  - Not-for-Profit Corporations (s.2.5.3)
  - Specific Service Charges (s.2.8.6) – Wireline Pole Attachment Charge
  - Clarification of accounting treatment of Other Revenues (s. 2.3.3) and Shared Service/Corporate Cost Allocation (s. 2.4.3.2), including instructions to treat microFIT charges as revenue offsets

Chapter 2 – Key Changes con’t

- Removals and Clarifications
  - Removal of reference to the Handbook for Utility Rate Applications (s. 2.0)
  - Removal of Accounting Guidance for IFRS transition (s.2.0.10 & s.2.9.1/2/3)
  - Removal of detailed DSP requirements from Ch. 2 (s.2.2.2) and addition of capital expenditures summary
  - Removal of Advance Capital Module (ACM) (s.2.2.2.6) and condensed rate base treatment of previously approved ACM/ICM
  - Removed Reliability Performance Indicators (s.2.2.2.8)

- Relatively few changes to existing Models and Appendices
  - Expanded GA Workform
  - New 1595 Workform
  - New Wireline Pole Attachment Workform
  - New Cost-of-Power calculation (Commodity portion) Appendix 2-Z

Administrative Documents

- Plain-language Summary (s. 2.1.3)
  - A stand-alone plain language summary requirement has been added. This summary will be posted on the OEB's website and will be available to customers
  - The summary must include a description of the impact of the request, individually and collectively on each of the residential and small business customer classes and the reasons for the impacts
  - The executive summary and application's summary (detailed application summary) (s. 2.1.6) remain unchanged

- Community Meeting (s. 2.1.7)
  - In order to expedite the community meeting process, the distributor is required to identify in its application a location for a community meeting. As the meeting must be advertised in a bill insert, the OEB will initiate the process of planning the community meeting before the application has been deemed complete
  - To ensure that the community meeting(s) does not significantly alter hearing timelines, the OEB expects a distributor to advise the OEB in writing no later than 30 days prior to filing its application of its intention to file with the OEB
  - This advanced notice will allow the OEB to contact the distributor and begin planning the meeting(s)

Allowance for Working Capital

- Impact of the *Fair Hydro Plan Act* on Cost of Power Calculation

  - Historically, the commodity price estimate used to calculate the Cost of Power was determined by the split between RPP and non-RPP customers based on actual data and using the most current RPP (TOU) prices

  - Going forward, distributors must consider all other impacts from the *Fair Hydro Plan Act, 2017*
    - Described in the OEB report *Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 – April 30, 2019,* in particular the impact of the GA modifier on non-RPP customers

  - Added requirement to split non-RPP consumption data between Class A and Class B customers and further sub-divide Class B non-RPP customers consumption data based on GA eligibility

  - The GA modifier must be applied to the applicable consumption data

  - Appendix 2-Z provides a model for calculating the cost of the commodity portion of the cost of power calculation

Lost Revenue Adjustment Mechanism Deferral Account

- LRAMVA disposition (s.2.4.6.2)
  - The current CDM guideline states that a distributor must apply for disposition of LRAMVA balances at the time of a CoS application
  - Chapter 2 now includes a provision that a distributor must provide a rationale for disposing the balance in the LRAMVA, if one or more rate classes do not generate significant rate riders
  - Additional filing requirements were added for LDC street lighting project(s) completed in collaboration with municipalities:
    - methodology to calculate savings
    - confirmation that savings were in accordance with load profiles accepted by the OEB
    - confirmation re. IESO funding and provision of net-to-gross assumptions
  - Removal of filing requirements of OEB-approved programs prior to 2014

Capital Structure – Not-for Profit Corporations

Not-for Profit Corporations (s. 2.5.3)

- Clarified filing requirements regarding a utility's reserve fund to accommodate different approaches to reserve funds by the various not-for-profit utilities

- A not-for-profit distributor must provide its requested capital structure and cost of capital and identify whether revenue derived from the return on equity component will be used to fund reserves

- If the revenues derived from the return on equity component of the cost of capital will be used to fund reserves a distributor must provide the following:
  - Description of governance
  - Statement and rational if these funds are used for non-distribution activities

- If an applicant has approved reserves from previous decisions the applicant must provide the following:
  - Limits of any capital and/or operating reserves as approved
  - Current balances of any established capital and/or operating reserves

Specific Service Charges

- Wireline Pole Attachment charges (s. 2.8.6)
  - The OEB issued its *Report on Wireline Pole Attachment Charges* on March 22, 2018
  - Pole Attachment charges were increased from $22.35 to $43.63, effective Jan. 1, 2019 with a transition period from September 1 - December 31, 2018 at $28.09 for all distributors who do not have a utility-specific pole attachment charge
  - Excess incremental revenue must be recorded in a new variance account
  - Distributors must refund excess incremental revenue at its next CoS application
  - For distributors filing a 2019 CoS application the balances in this account will be out of scope
  - Distributors that are applying for a utility-specific pole attachment charge must submit specific inputs from the appropriate sub-accounts and file the OEB's Pole Attachment workform

Other revenues

- Clarification regarding accounting treatment of Other Revenues (s. 2.3.3)
  - Instruction to treat MicroFit charges as other revenues have been added
    - revenues must be recorded as a revenue off-set in Account 4235 – Miscellaneous Service Revenue and not be included as part of the base revenue requirement
  - Requirement to reconcile balances recorded in Account 4375, Revenues from Non Rate-Regulated Utility Operations, and Account 4380, Expenses of Non Rate-Regulated Utility Operations,
    - these balances must also reconcile to the balances recorded in Appendix 2-N
  - Ensure that transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business, products or services
    - if cross-subsidization occurs, the applicant must describe this issue in more detail and provide an explanation as to why the applicant has not rectified this issue
  - Identify any discrete customer groups that may be materially impacted by changes to other revenues

Other revenues – con't

- Additional clarification provided on the appropriate accounts to record revenues and expenses from affiliate transactions, as follows:
    - Account 4325, Revenues from Merchandise
    - Account 4330, Costs and Expenses of Merchandising

    - Account 4375, Revenues from Non Rate-Regulated Utility Operations
    - Account 4380, Expenses of Non Rate-Regulated Utility Operations

Other revenues con’t

- Shared Service/Corporate Cost Allocation (s. 2.4.3.2)
    - Shared Services and Corporate Cost Allocation costs that are included in an applicant’s OM&A must be excluded from the account balances incorporated into Other Operating Revenue and vice versa
    - Added requirements to explain and provide further detail regarding shared services and corporate cost allocation listed in Appendix 2-N
        - Shared Services
            - The type of service provide or received
            - The pricing methodology (e.g. cost-base, market-base, tendering etc.)
        - Corporate Cost Allocation
            - A list of shared services
            - The allocation methodology
            - A list of costs and allocators and an explanation of how the distributor derived the allocator
            - Any third party review of the corporate cost allocation methodology used

Chapter 2 – Removals and Clarifications

- Removal of reference to the Handbook for Utility Rate Applications (s. 2.0) and the OEB's expectations
  - Duplication of filing requirements in Chapter 1
- Removal/changes to Accounting Guidance for IFRS transition
  - Removal of detailed accounting guidance for IFRS transition
  - Distributors that have not rebased under IFRS accounting guidance are requested to consult previous FRs or contact OEB staff
  - Added requirement to update for any further material changes on the adoption of IFRS on January 1, 2015 for audited financial statement purposes
  - Impacts should also be recorded in Account 1575, including an explanation. If no material changes were identified, the applicant should indicate the total dollar value of the change, explain why the change was not material and provide a statement confirming that it has considered all possible impacts
- Uniform Transmission Rates (UTRs) and Smart Metering Entity Charge
  - Specific reference to the respective decision (e.g. docket number and date of issuance) on UTRs and the Smart Metering Entity charge have been replaced with a general statement that a distributor must use the most recent approved UTRs and Smart Metering Entity charges

Distribution System Plan (DSP) and Capital Expenditures Request

Capital Expenditures (s. 2.2.2) – Moved to Chapter 5

- A distributor must file a consolidated DSP in accordance with the newly updated Chapter 5. Most requirements regarding the DSP or detailed capital expenditure projects have been moved from chapter 2 to chapter 5

- Chapter 2 retains a requirement to provide a stand-alone capital expenditure summary over the past five historical years, bridge and test year, showing capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress (CWIP) and file year-over-year variance analysis as part of exhibit 2 (s. 2.2.2.2)

- Distributors are required to update previous approved amounts for GEA funding as part of the new rate application
  - this will result in new up-to-date rate protection amounts going forward

- Service Quality Requirements remain while Reliability Performance Indicators have been moved to chapter 5 DSP requirements (s. 2.2.2.8)

Changes that were also made to Chapter 3

- CBR disposition updates
- Clarification regarding the disposition of Global Adjustment Variance
  - disclosure of subsequent adjustment recorded after the initial transaction from preliminary estimates to actual amounts based on consumption data (nature, timing and $ impact) as part of the GA Analysis Workform
- Additional requirement of Account 1595 Workform in Appendix A
  - residual balances +/- 10% of the original principal and interest amounts previously approved for disposition would be considered material and amounts exceeding this materiality threshold need to be explained as part of the newly required 1595 Analysis Workform

Models and Appendices - 1

- The application review process remains a data-based exercise and the models and appendices are a key tool in expediting the preparation and review of applications and enhancing consistency between them

- There are 14 models including the Revenue Requirement Work Form, PILs Model, Cost Allocation Model and others

- There are approx. 31 different appendices. These provide standardized formats for presentation of key information required by the OEB as part of its application review process. Some examples include: 2-JA OM&A Summary Table, 2-OA Capital Structure and Cost of Capital and 2-R Loss Factors
  - the reduction in appendices is due to the removal of IFRS transition appendices

Draft Rate Order Model updates

- Models and appendices filed during the draft rate order process ensure that the final approved rates are supported by the evidentiary record

- Applicants are required to provide an updated Revenue Requirement Work Form (RRWF)

- Applicants are also required to update certain tabs in the Chapter 2 Appendices, if changes are necessary
  - the required tabs are indicated in the appendices themselves at the “Index” tab and applicants must file the workbook in its entirety at the draft rate order stage.

- This record will also be used to create an expanded application data base

Questions/Discussion

Update on Proportional Review Pilots

Jane Scott

July 19, 2018

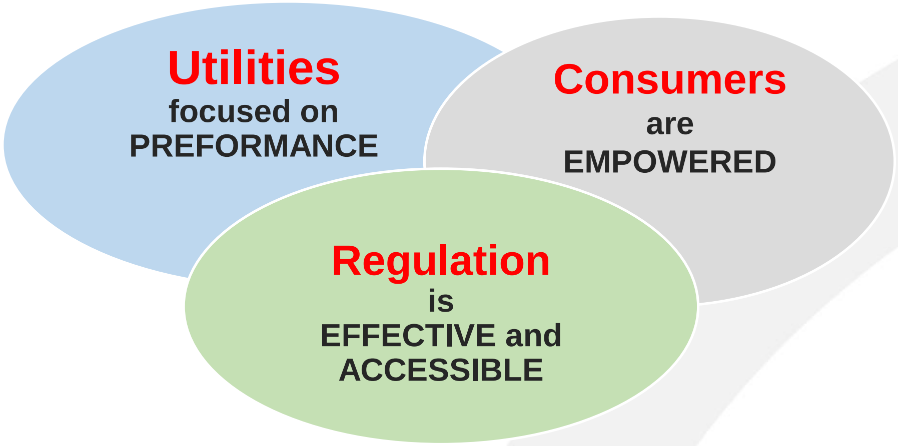
Proportionate Review Overview

Aims of proportionate review

- Align regulatory review process with performance based regulation
- Effective regulatory oversight through greater performance-based monitoring:
  - Reduce regulatory process for high performing utilities
  - Optimize time and resources by focusing regulatory resources on utilities and issues that require more detailed review
  - Reinforce OEB control over the hearing process
- Reward utility efficiency, good governance and customer focus
- Ensure regulatory flexibility to adapt to a rapidly changing sector

Proportionate Review Overview

Regulatory review is proportionate to performance



Performance

- Financial
- Operational
- Organizational
- Quality of service

Enablers

- Robust benchmarking
- Performance reporting and monitoring
- Best practices in corporate governance

Proportoinate Review Overview

Hallmarks of the proportionate review process

1. OEB Staff takes lead role in identifying issues
2. Up front in-depth assessment of:
   - Past performance of applicant
   - Alignment with OEB policy
   - Quality of support for rate proposals
3. Customer concerns are heard and recognized in selection of process steps
4. Application review is proportional to the application, the applicant and the issues

Proportionate Review Overview

Preliminary Review Assessment

Application Specific Factors

- Application type (e.g. number of years, rebasing vs. IRM, DVAs, etc.)
- Nature of request
- DSP, capital projects, workforce changes and other OM&A, innovations
- Responsiveness to customer feedback

Applicant Performance Against Benchmark & Continuous Improvement

- RRR, stretch factor group, customer feedback and complaints, corporate governance, audit
- RRFE outcomes
  Scorecard
- Trend analysis

OEB Policy Alignment

- New issues for which no current policy exists
- Deviations from existing OEB policy

Adjudicative Model Review Overview

Benefits of Proportionate Review

- Facilitates robust decision-making that focuses on material issues
- Rewards high performing applicants by tailoring review process to performance of applicant and nature of application
- Reduces time and cost of review where possible
- Reinforces the OEB's control of its process
- Allows greater procedural flexibility

Proportionate Review Pilots - Summary

What we did:

- Assessed the Initial Triage Model by shadow testing seven 2018 rebasing applications
- Tested the full proportionate review process with two 2018 cost of service applicants
  - Used OEB staff assessment to select a proportionate review process for those applications

Plan going forward:

- Seek stakeholder feedback after the two full pilots are complete
- Revise the ITM criteria and the assessment process as needed
- Shadow test 2019 rate applications

Proportionate Review - Pilots

Sioux Lookout Hydro

- Decision on Scope of Review issued March 29th
  - Five minor issues to hearing
  - hearing consists of exchange of written submissions - no cost awards offered
- Notice issued April 6th, OEB staff submission filed June 27th, Sioux Lookout to file reply July 18th

Erie Thames Powerlines

- Decision on Scope of Review issued June 8th
  - Six broad issues to full hearing
  - Four issues to an abridged hearing process; written submissions only
- Notice issued June 26th

Questions/Discussion

Forecasting using the OEB Cost Benchmarking Model

Jane Scott

July 19, 2018

Overview of Forecasting Capabilities

- The OEB has requested that LDCs filing for new rates provide information on cost benchmarking as a standard part of the filing.
- The OEB currently uses a cost benchmarking model to determine if changes in cost performance warrant changes in the stretch factors established as part of IRM
- 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.

The Benchmarking Forecast Model

- The forecast worksheet has been separated from the larger benchmarking calculations workbook
- A worksheet for LDC data inputs will be added with the following
  - 2017 historical values
  - Column for 2019 test year data
  - 7 “bridge” year data
  - Columns for 2020-2024 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

Data Requirements

- Eleven data items are required:
  - OM&A expenses as adjusted
  - Gross 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 2019 test year
- For those proposing custom IR, the model has the capability to go out to 2024
- 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.
- There was a training session on May 22, 2015 on Benchmarking. The materials 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
- The gross capital additions should <u>not</u> be reduced by contributions
- Depreciation is standardized across LDCs
- Plant additions are separated into quantity and price each year.
- A "perpetual inventory" method is used to track the <u>quantity</u> 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 <u>not</u> 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

- Training Session Materials
- The Users Guide for the Benchmarking Model
- 2018 Benchmarking Forecast Model

It may be necessary to right-click the above links and select "open hyperlink" to access the file on the OEB website

Chapter 5
Filing Requirements Update for 2019 Applications

Summary of Key Changes and Keys to Success

Jane Scott and Donald Lau

July 19, 2018

Chapter 5 – Key Changes

- Chapter 5 - additions
  - Added considerations from the Long Term Energy Plan
  - Added one chapter 5 appendix
  - Emphasized relationship between capital spending and O&M costs
  - Timing of distribution system plan filings for deferred COS
- Chapter 5 - deletions
  - Duplications within Chapter 5 and Rate Handbook removed or condensed
- Chapter 5 - moves
  - Moved relevant Distribution System Plan sections from Ch. 2 to Ch. 5
  - Combined sections related to planning with 3rd parties and performance reporting
  - Reorganized sections to provide better flow for reader in terms of understanding the evidence required

Chapter 5 – Additions

- Long Term Energy Plan (LTEP)
  - Added information required for high level overview of DSP (section 5.2.1)
    - “Identification of projects related to cost-effective grid modernization, distributed energy resources, and climate change adaptation and how these projects address the goals of the Long-Term Energy Plan.”
  - Emphasized that the LTEP reinforces the current process and capital expenditures should be evaluated through risk management (section 5.4.1)
    - “A detailed description of the analytical tools and methods used for risk management and its correlation to the capital expenditure plan. A distributor is responsible for managing its business risk in a manner to achieve its objectives through a comprehensive risk portfolio. These risks could include, but not limited to, system reliability, cyber-security, and climate change adaptation.”

Chapter 5 – Additions

- Long Term Energy Plan (LTEP)
  - Emphasis on grid modernization (Section 5.4.1)
    - "A distributor's strategy in taking advantage of opportunities that arise during system planning to implement cost-effective modernization of the distribution system such that it becomes more efficient, reliable, and provide more customer choice. "
  - Emphasis on distributed energy resources (Section 5.4.1)
    - A distributor's strategy for "The investments necessary to facilitate the integration of distributed generation, distributed energy resources and more complex loads (e.g., customers with self-generation and/or storage capability)"
  - Emphasis on innovation (Section 5.4.3)
    - "A distributor should also keep pace with technological changes and integrate cost-effective innovative projects and traditional planning needs such as load growth, asset condition and reliability."

Chapter 5 – Additions

- Long Term Energy Plan (LTEP)
  - Emphasis on system resilience to climate and technological change (Section 5.4.3.2)
    - An investment should "Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change)"
  - Emphasis on cyber-security expectations (Section 5.4.3.2)
    - "Cyber security is expected to be incorporated into the distributor's risk management decision making and investment planning to form part of its business plans and DSP"

Chapter 5 – Additions

- Chapter 5 appendix
  - Appendix 5-A Metrics
    - Proposed metrics that can be used to quantitatively measure performance
    - Unit cost metrics for capital expenditures and O&M per customer, kilometer of line, and peak capacity
- Emphasized relationship between capital spending and O&M costs (Section 5.4.2)
  - “A distributor is expected to consider the reduction in O&M costs when planning capital projects. A description of the impacts of capital expenditures on O&M must be given for each year or a statement that the capital plans did not impact O&M costs. A distributor must consider the trade-offs between capital and O&M when assessing alternative options to a capital program”

Chapter 5 – Additions

- Timing of distribution system plan filings for deferred COS (Section 5.1.2)
  - "A distributor that has requested deferral of its cost of service application and received OEB approval will be notified in the approval letter as to the requirement for and timing of a DSP filing."

Chapter 5 – Deletions

- Duplications within Chapter 5 and Rate Handbook removed or condensed
  - Removed redundant definitions within chapter 5 and rate handbook with references or the glossary
  - Removed paragraphs that are better defined in the rate handbook (integrated planning, long-term planning horizon, and regional planning)
  - Condensed redundant themes within chapter 5 (framework of the DSP, performance measurement, and planning information for capital expenditures)

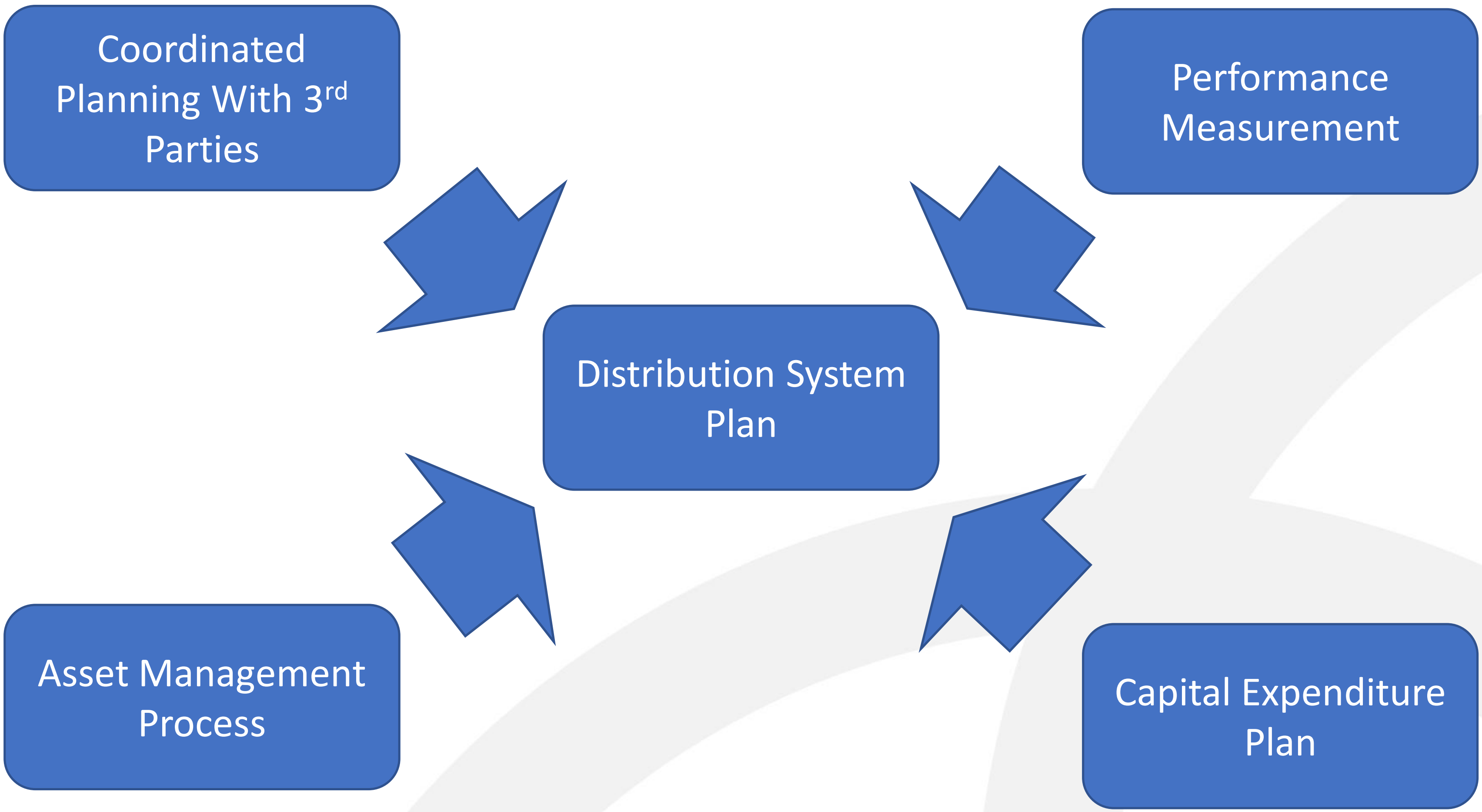
Chapter 5 – Moves

- Moved relevant Distribution System Plan sections from Ch. 2 to Ch. 5
  - Reliability performance metrics SAIDI and SAIFI (Section 2.2.2.8)
  - Efficiencies realized due to smart meters (Section 2.2.2.2)
  - Description of distribution system (Section 2.1.4)
  - Rate funded activities to defer distribution infrastructure (Section 2.2.2.2)
  - Capital expenditure summary (Section 2.2.2.2)
  - Capital contributions made to transmitter (Section 2.2.2.2)

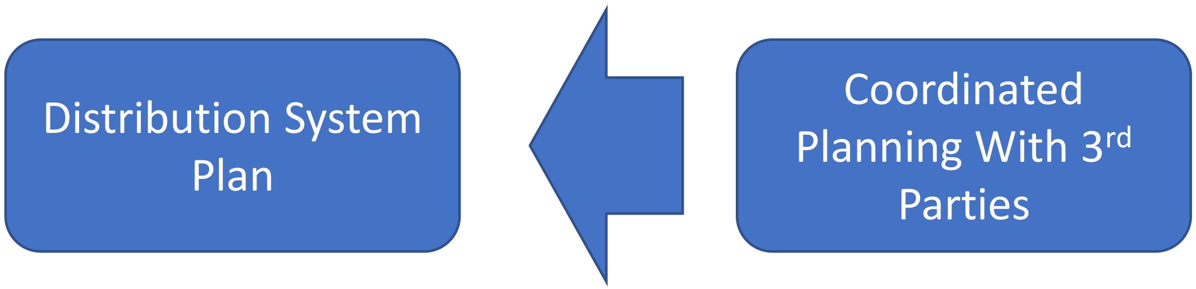
Chapter 5 – Moves

- Combined sections related to planning with 3rd parties and performance reporting
  - Grouped together sections related to regional planning and coordination with IESO for renewable energy generation into the DSP overview
- Reorganized sections to provide better flow for reader in terms of understanding the evidence
  - Moved “System Capability Assessment for Renewable Energy Generation” from capital expenditure plan to overview of assets managed

Chapter 5 – Keys to Success

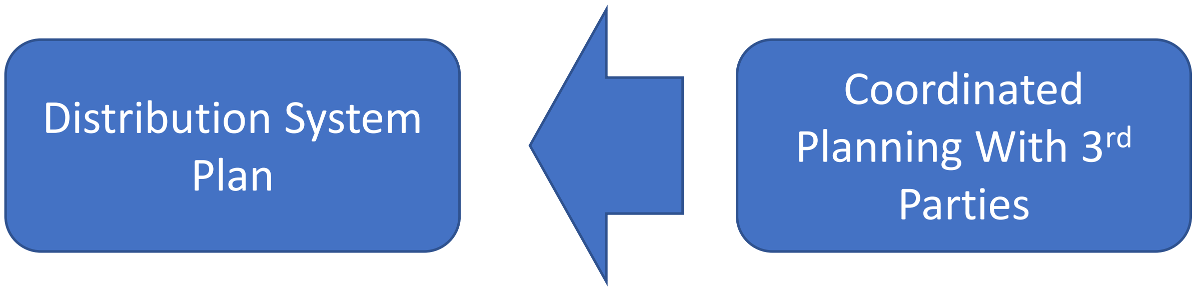


Chapter 5 – Keys to Success



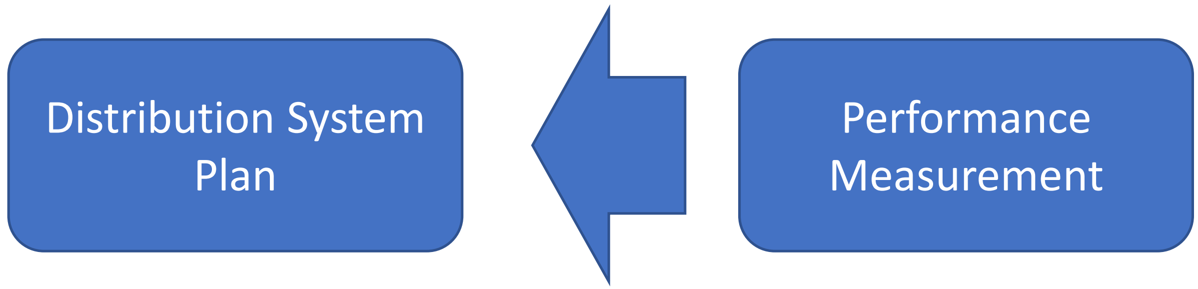
- Consultation Components
  - Purpose?
  - Distributor initiated or invited?
  - Other participants?
  - Nature and timing of deliverable
  - How the consultation affected the DS Plan
- Examples
  - Regional Planning Process and customer consultation

Chapter 5 – Keys to Success



- Successes
  - Utilities have included different methods used to gather customer input
- Area of Improvement
  - Customer consultation is not a satisfaction survey

Chapter 5 – Keys to Success



- Performance Measurement Components
  - Identify performance metrics
  - Performance trend
  - How performance trend affected DS Plan
- Examples
  - Unit cost metrics (Appendix 5-A)
  - Reliability/Power quality
  - Actual vs. planned costs

Chapter 5 – Keys to Success

- Process Overview
  - Relationship between asset management objectives and corporate goals
  - Asset management objective prioritization
  - Asset information
  - Input/output to the process

Chapter 5 – Keys to Success

- Assets Managed
  - Distribution service area overview
  - System configuration
  - Asset profile
  - Asset capacity in relation to planning

Chapter 5 – Keys to Success

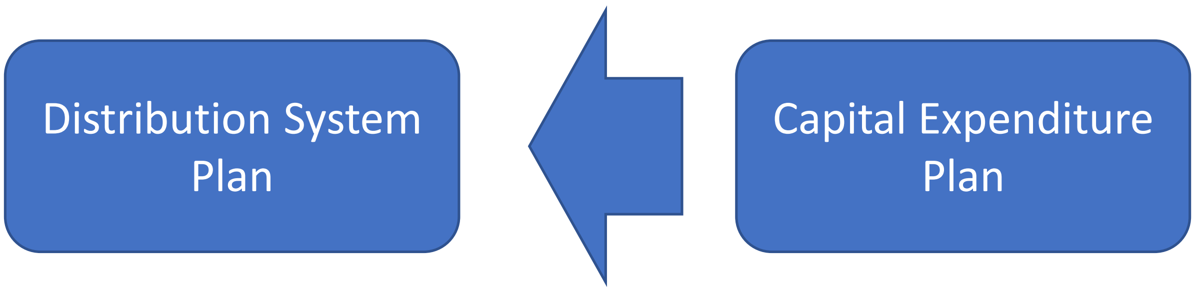
- Successes
  - Most LDCs are utilizing some kind of asset registry
  - Some LDCs are doing extensive condition assessments
- Area of Improvement
  - Asset age alone is not a strong metric for asset management
  - Provide clear link of asset condition plan and proposed capital expenditures

Chapter 5 – Keys to Success

Distribution System Plan ← Asset Management Process ← Lifecycle Optimization Policies and Practices

- Policies and Practices
  - Replacement and refurbishment
    - Maintenance planning criteria
    - Preventative inspection
  - Asset life cycle risk management
    - Risk assessment
    - Select and prioritize capital expenditures
    - Mitigation methods

Chapter 5 – Keys to Success



- Capital Expenditure Plan Components
  - Process Overview
  - Capital expenditure summary
  - Justifying capital expenditures

Chapter 5 – Keys to Success

Distribution System Plan ← Capital Expenditure Plan ← Capital Expenditure Process Overview

- Process Overview
  - Planning objectives
  - Alternative system relief
  - Tools and methods
  - Customer engagement
  - Cost-effective modernization of system

Chapter 5 – Keys to Success

Distribution System Plan ← Capital Expenditure Plan ← Capital Expenditure Process Overview

- Successes
  - Utilities have utilized a systematic approach to investment planning
- Area of Improvement
  - Stronger investment selection algorithm (e.g. risk mitigated per dollar spent)

Chapter 5 – Keys to Success

- Investment Details
  - How does the investment meet goals?
  - Alternatives (consider CDM)
  - Prioritization
  - Pacing of continuous projects
  - Capital and O&M trade-off
  - How does it align with performance outcomes

Chapter 5 – Keys to Success

- Area of Improvement
  - Alternative
  - Greater consideration of capital to OM&A trade-off
  - Project prioritization method not specific
  - Performance level tracking
  - Project benefits need to be quantified
  - Robust link between customer engagement and projects

Questions/Discussion

Ratepayer Groups’ Perspective

2018 OEB’s Orientation Session for Electricity Distributors Rebasing

Mark Rubenstein –*Co-counsel to the School Energy Coalition*

Shepherd Rubenstein

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, CCC, SEC
  - Sometimes – AMPCO, Energy Probe, and BOMA
- Intervenor Representatives: Experienced lawyers and consultants
- Work collaboratively

Why are we all here

- Regulation as a substitute for competition – Board as market proxy
- Each ratepayer group represents a segments of your customer base
- 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
- Previous applications, results, rates, decisions
- 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 are very 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
- 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

Process - Interrogatories

- "The purpose of the interrogatory process is to test the evidence"
    - Filing Requirements For Electricity Distribution Rate Applications
- What we are looking for?
    - More detail
    - Documents referred to (or omitted), sometimes prior versions
    - Explanations
    - Missing data, steps, or confusion
    - Underlying 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

Process - 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
  - Expectation is the answers are put on the record

Process - 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

Process - 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
  - Willingness to compromise/listen – on both sides
  - Hearings can lead to rough justice, settlements allow for creative solutions
  - Achieve a known result versus the unknown of a Board decision

Process Oral Hearings

- Pre-Oral Hearing Questions
  - Technical or data heavy questions provided in advance to limited undertaking requests and bogging hearing down unnecessarily
- Cross-examination
  - 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

Consistent Issues

- Implementing the goals of the RRFE
  - Outcome focus – Metrics and targets
  - Value for money
  - Benchmarking
  - Robust capital planning requirements
  - Customer Engagement – rates versus reliability
- Customer growth or decline
- Past underinvestment or past significant investment – what is the end state?
- Show us the plan
- Poor accounting
  - Make sure your numbers are correct
  - Spending extra time on the front end to save time on the back end

The Future

- Proportionate Review – Test cases on-going
- Community Days – how does the feedback enter into the Board's decision process
- Hearings in the community

Thank you

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Shepherd Rubenstein

2019 Cost of Service Filers Orientation Session

Appendices and Models

Marc Abramovitz/Andrew Frank/Judy But/Dan Gapic

July 19, 2018

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 from processing applications
    - Changes in informational needs
- Consistency in data presentation facilitates easier and quicker review of many applications by OEB panels, staff, stakeholders
- At the same time, we try to balance the need for information versus the amount of data and the effort to collect and input it
- All models have been updated to reflect revised rate year and current list of LDCs

Changes to Chapter 2 Appendices

- Additions and modifications in 2018:
  - Modified: List of Key References
  - Added: worksheet 2-Z, Commodity Expense (Cost of Power Calculation)
  - Modified: worksheet 2-AB and 2-K
  - Modified: worksheet 2-M
  - There are hidden worksheets related to IFRS
- Most other sheets have had minor formatting and other changes
  - Improve use, inputs and presentation, but do not materially affect calculations

Changes to Chapter 2 Appendices

NEW: certain worksheets in the Chapter 2 Appendices file must be updated and refiled during the draft rate order stage to reflect cost of service decision.

- The following tabs in the file to be updated and then refiled along with the final version of the RRWF
  - Appendix 2-AB – Capital Expenditures
  - Appendix 2-FA, 2-FB, 2-FC – Renewable Generation Connection
  - Appendix 2-H – Other Operating Revenues
  - Appendix 2-JA - OM&A Summary Analysis
  - Appendix 2-K – Employee Costs
  - Appendix 2-M – Regulatory Costs Schedule

Changes to Chapter 2 Appendices

- Appendix 2-Z Commodity Expense:
  - Effective July 1, 2017 the Ontario Fair Hydro Plan was implemented.
  - Impact was a reduction to RPP Revenue and cost of power.
  - The OFHP impacted the cost of power, working capital allowance, rate base, and ultimately the service revenue requirement.
  - To assist distributors in forecasting a reasonable amount for the cost of power the OEB has provided Appendix 2-Z.
  - This appendix calculates only the commodity component of the cost of power, not the other components.
  - Distributors are to forecast the other components of cost of power and combine with the commodity expense.

Changes to Chapter 2 Appendices

- Appendix 2-Z Commodity Expense, Cont'd:
  - Proportions of Commodity kWh volumes and amounts are broken down into the following components based on the last historical actual volumes:
    - Class A customer commodity cost
    - Class B RPP customer commodity cost
    - Class B non-RPP customers not eligible for GA Modifier
    - Class B non-RPP customer eligible for GA Modifier

Changes to Chapter 2 Appendices

- Appendix 2-Z Commodity Expense, Cont'd:
  - Class A customer Commodity cost:
    - ➢Energy Cost
      - ✓ historical actual proportion of Class A GA kWh X
      - ✓ forecast test/bridge year wholesale kWh X average HOEP, plus
    - ➢Global Adjustment (GA) Cost for Test and Bridge Years:
      - ✓ forecast test/bridge year Class A kW demand X
      - ✓ ratio of last historical actual (Class A $ GA / Class A kW)
      - ✓ If distributor expects that the Class A volumes and ratio of (Class A $ GA / Class A kW) will be significantly different, the distributor can adjust the proportions listed in the previous slide, must be supported with details of adjustment

Changes to Chapter 2 Appendices

- Appendix 2-Z Commodity Expense, Cont'd:
  - Class B customer Commodity cost:
    - Weighted average commodity cost for all Class B customers based on proportions of volumes at applicable rate for each of the three Class B customer groups, multiplied by
    - kWh volumes by customer class.

Changes to Chapter 2 Appendices

Worksheet 2-Z – Commodity Expense

Commodity Expense

Step 1: **Allocation of Commodity**

2017 Historical Actuals

Customer Class Name		Last Actual kWh's	Class A kWh	Class B kWh	non-RPP non GA mod	non-RPP GA mod	non-RPP Total	RPP	Proportions (by Class) non-RPP %	Proportions (by Class) RPP %	
Residential		44,896,468		44,896,468	-	2,237,918	2,237,918	42,658,550	4.98%	95.02%	
General Service < 50 kW		23,270,826		23,270,826	-	4,473,332	4,473,332	18,797,494	19.22%	80.78%	
General Service 50 to 2999 kW		50,553,990	500,000	50,053,990	49,709,096	-	49,709,096	344,894	98.33%	0.68%	
General Service 3000-4999 kW		18,344,949	2,500,000	15,844,949	15,844,949	-	15,844,949	0	86.37%	0.00%	
Unmetered Scattered Load		562,067		562,067	22,368	-	22,368	539,699	3.98%	96.02%	
Sentinel Lighting		39,303		39,303	12,954	-	12,954	26,349	32.96%	67.04%	
Street Lighting		566,049		566,049	566,049	-	566,049	0	100.00%	0.00%	
other		-		-	-	-		0			
other		-		-	-	-		0			
TOTAL		138,233,652	3,000,000	135,233,652	66,155,416	6,711,250	72,866,666	62,366,986			
%		100.00%		100.00%	48.92%	4.96%		46.12%	53.88%	46.12%	100.00%

Step 2: **Forecasted Commodity Prices**

Step 2a:			non-RPP		
GA Modifier	($/MWh)		$ (44.38)	Source:	Table 1: RPP Prices and GA Modifier: May 1, 2018 to April 30, 2019*

Step 2b: Forecasted Commodity Prices — Table 1: Average RPP Supply Cost Summary**

			non-RPP non GA mod	non-RPP GA mod	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$21.57	$21.57	
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$103.80	$59.42	
Adjustments ($/MWh)			$1.00	$1.00	
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$126.37**	**$81.99**	**$81.99**
$/kWh			***$0.12637***	***$0.08199***	***$0.08199***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		48.92%	4.96%	46.12%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.1037	**$0.0618**	**$0.0041**	**$0.0378**

Changes to Chapter 2 Appendices

Worksheet 2-Z – Commodity Expense

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

				2018					2019				
Customer		**Revenue**	**Expense**	**kWh Volume**	**kW Volume**	**HOEP Rate/kWh**	**Avg GA/kW**	**Amount**	**kWh Volume**	**kW Volume**	**HOEP Rate/kWh**	**Avg GA/kW**	**Amount**
General Service 50 to 2999 kW		4035	4705	500,000	114	0.02157	215	$35,295	600,000	122	0.02157	205	$37,952
General Service 3000-4999 kW		4010	4705	2,500,000	439	0.02157	195	$139,530	2,800,000	465	0.02157	186	$146,886
				3,000,000	553			$174,825					$184,838

Class B

				2018					2019				
Customer		**Revenue**	**Expense**										
Class Name	UoM	USA #	USA #	Volume	rate ($/kWh):			Amount	Volume	rate ($/kWh):			Amount
Residential	kWh	4006	4705	47,768,829	0.1118			$5,340,555	43,594,767	$0.1037			$4,520,795
General Service < 50 kW	kWh	4010	4705	22,002,634	0.1118			$2,459,895	20,099,457	$0.1037			$2,084,322
General Service 50 to 2999 kW	kWh	4035	4705	62,819,812	0.1118			$7,023,255	56,984,117	$0.1037			$5,909,276
General Service 3000-4999 kW	kWh	4010	4705	17,404,327	0.1118			$1,945,804	15,341,086	$0.1037			$1,590,877
Unmetered Scattered Load	kWh	4025	4705	587,229	0.1118			$65,652	568,728	$0.1037			$58,977
Sentinel Lighting	kWh	4025	4705	41,291	0.1118			$4,616	39,658	$0.1037			$4,113
Street Lighting	kWh	4025	4705	596,240	0.1118			$66,660	579,454	$0.1037			$60,090
other	kWh	4025	4705	0	0.1118			$0	0	$0.1037			$0
other	kWh	4025	4705	0	0.1118			$0	0	$0.1037			$0
TOTAL				**151,220,361**				**$16,906,436**	**137,207,268**				**$14,228,450**

Total

				2017					2018				
Customer		**Revenue**	**Expense**										
Class Name	UoM	USA #	USA #	Volume	avg rate ($/kWh):			Amount	Volume	avg rate ($/kWh):			Amount
Residential	kWh	4006	4705	47,768,829	0.1118			$5,340,555	43,594,767	0.1037			$4,520,795
General Service < 50 kW	kWh	4010	4705	22,002,634	0.1118			$2,459,895	20,099,457	0.1037			$2,084,322
General Service 50 to 2999 kW	kWh	4035	4705	63,319,812	0.1115			$7,058,550	57,584,117	0.1033			$5,947,228
General Service 3000-4999 kW	kWh	4010	4705	19,904,327	0.1048			$2,085,334	18,141,086	0.0958			$1,737,763
Unmetered Scattered Load	kWh	4025	4705	587,229	0.1118			$65,652	568,728	0.1037			$58,977
Sentinel Lighting	kWh	4025	4705	41,291	0.1118			$4,616	39,658	0.1037			$4,113
Street Lighting	kWh	4025	4705	596,240	0.1118			$66,660	579,454	0.1037			$60,090
other	kWh	4025	4705	0	0			$0	0	0.0000			$0
other	kWh	4025	4705	0	0			$0	0	0.0000			$0
TOTAL				**154,220,361**				**$17,081,261**	**140,607,268**				**$14,413,288**

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 – April 30, 2019*

*** Regulated Price Plan Cost Suppy Report May 1, 2018 - April 30, 2019*

Changes to Other Models

- Cost Allocation
- DVA (Continuity Schedule) Workform
- LRAMVA Workform
  - Modified Worksheet 6 – LDCs are to include projected interest amounts
- PILs
- RTSR
  - No material change from last year; will be updated when 2019 UTRs issued
- RRWF
- ACM/ICM Model
  - Model has been updated to account for an approved deferral period above and beyond the 4 year IRM period
  - New version will be issued shortly.

Tariff Schedule and Bill Impacts Model

- Separate model that generates the current and proposed Tariff Schedule and subsequently the Bill Impacts
- Follows the format in the IRM model
  - Current Tariff populated by rates database
  - Regulatory rates (prepopulated but unlocked)
  - Additional rate riders (entered by Applicant)
  - **New:** Proposed tariff schedule will be generated based on inputs on previous sheets

Revenue Requirement Workform (RRWF)

- RRWF goes beyond just calculating and verifying the revenue requirement
- Links 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
  - Sheet 12 – Residential Rate Design
  - Sheet 13 – Rate Design and Revenue Reconciliation
- “Summary of Proposed 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, summarizes 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 and other models that an applicant uses.
- The RRWF, just like the other models you may use, is 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.

Parting remarks on models

- Models are designed to be flexible and accommodate most situations, but it is not possible to contemplate every utility's circumstances
- Many models and sheets are unlocked, but where they are locked, it is for a reason:
  - Preserve integrity of model calculations
  - Proper operation of a model, particularly if macro-driven, may depend on structure
- Staff will try to assist, but availability is subject to time and resources.

Next Up …

Cost Allocation

Cost Allocation Policy: Your Last Filing (2014)

- 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, host 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:
  - Load Displacement Generation (EB-2013-0004)

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

Notice of Amendment to a Code, issued May 15, 2014:

- Section 2.4.6 of the Distribution System re: unmetered customers
- Took effect Jan. 1, 2015

s. 2.4.6:

- 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:

- 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 concluded
  - OEB Rate Design Report, issued April 2, 2015, indicated that the OEB intends to remove the standby rate when the new rate design policy implemented for commercial customers
  - New commercial customer rate design to be developed through a separate consultation process
  - Until then, the 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: Summary

- 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 CA study reflects most recent data obtained from unmetered customers through 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 on how numbers were derived/confirmed

- Tighter Revenue-to-cost ratio range for street lighting class

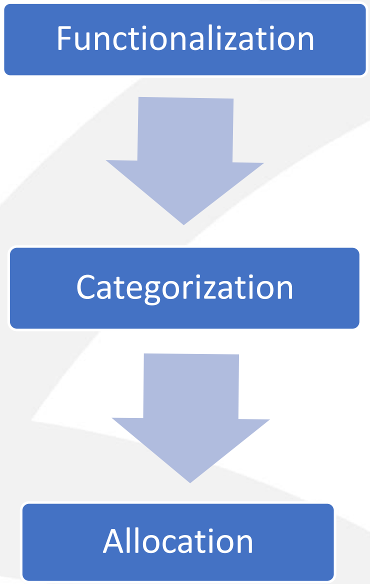
Cost Allocation Filings: 2013-2018

- **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, with discussion, how it intends 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**
  - Information required of host distributor, if no separate class of embedded distributor(s)
  - Provides sharper focus on embedded distributor(s) than CA Model
- **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
  - For 2018, “sanity checks” to highlight invalid data and situations

Cost Allocation Framework

Conceptual Framework unchanged

- 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



Cost Allocation Models: Version summaries

Yr.	V.	Key Changes
2015	3.2	• Additional instructions – Sheets I4 (Asset Break-out) and I6.1 (Revenue) • Correction in Cell C148 of sheet I9 (Direct Allocation) for calculation of cost of capital and associated taxes/PILs on NBV of directed allocated costs

2016	3.3	• Street Lighting class cost allocation per new OEB policy
		  • Street Lighting Adjustment Factor (SLAF) calculated on sheet I6.2. Cells J22 and J23 divide number of devices by the SLAF for allocation of primary and secondary transformer assets
		  • On sheet E3, formulae for CCP and CCLT takes values calculated on I6.2 for SL class
		  • On sheet I2, Residential, GS < 50 kW and SL classes are locked for proper calculation of SLAF
		  • LDC must include both device and connection data. If not used in previous CA studies, applicant should describe how number of devices and connections were derived/verified

2017	3.4	• Instructions updated, including removal of outdated instructions
2018	3.5	• “Sanity checks” – to ensure that anomalous situations are identified (e.g. NCP4 <= 4 x NCP)

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

Next Up …

Pole Attachments

OEB Pole Attachment Work Form

- If a distributor is seeking to apply for a custom pole attachment charge, distributors must:
  - File the Pole Attachment Work Form using distributor specific inputs and costs from sub-accounts
  - Address Chapter 2 Filing Requirements

- Filing Requirements for Wireline Pole Attachments (Section 2.8.6) require LDCs to:
  - Summarize outcomes of the pole attachment work form
  - State reasons for the proposed change(s) to new provincial charge of $43.63/attacher coming into effect on Jan. 1, 2019

- Pole Attachment Work Form has 8 tabs (4 tabs require data input)
  - Outputs from Tabs 2, 3 and 4 are linked back to Summary Tab

OEB Pole Attachment Work Form

- Tab 1: Summary Tab
- Tab 2: Attacher and Pole Data
- Tab 3: Direct Costs
- Tab 4: Indirect Costs
- Tab 4-a: Power Deduction Factor (as applicable)

OEB Pole Attachment Accounting Guidance

- Wireline pole attachment rate changing from $22.35/pole to $28.09/pole on Sept 1, 2018 to end of year, then to $43.63/pole effective Jan 1, 2019.
- Pole attachment charge to be adjusted by the OEB's inflation factor annually starting Jan 1, 2020.
- LDCs are to record the excess incremental revenues in a new variance account, Account 1508 – Sub Account – Pole Attachment Revenue Variance. i.e. the revenue difference between the currently approved rate and the relevant rate charged.
- Carrying Charges will apply
- The monthly amount to record is to be calculated based on 1/12th of the excess revenue amount of the annual pole attachment charge multiplied by the relevant number of poles per month.

OEB Pole Attachment Accounting Guidance

- LDC's to use the new variance account until the next rebasing year when the new pole attachment revenue has been reflected in revenue offsets.
- If amounts that accumulate are assessed to be material prior to next rebasing or if LDC in midst of an extended deferral period, may propose to dispose in an IRM application.
- When these account balances are disposed, the LDC will allocate costs to customer classes in a cost of service application based on test year forecast data and based on the most recent historical actual data in IRM applications.
- Billing determinants used to calculate the rate riders would be number of customers for the Residential Class, and consumption/demand for other customer classes.

Next Up …

Accounting Matters

- Review of filing requirements & workforms

Questions

Orientation Session
Electricity Distributors Rebasing for 2019 Rates

Accounting Matters – Review of Filing Requirements & Models

Rajvinder Sabharwal & Alex Share

July 19, 2018

Agenda

- Ontario Fair Hydro Plan
- Accounting Standards
  - Capitalization & Depreciation Policy Changes
  - Adoption of IFRS
- Pensions & OPEBs
- Changes to PILs model
- Updates to DVA Continuity Schedule & Key Points
- Takeaways from 2018 Applications
- Supplementary Models to DVAs
  - GA Analysis Workform updates
  - Account 1595 Workform
- Questions

Ontario Fair Hydro Plan (OFHP)

- OFHP has been in effect since July 1, 2017
- OEB issued a letter on the Implementation of the OFHP on June 29, 2017
- OEB issued detailed Accounting Guidance on October 31, 2017
  - Bill reductions to RPP customers through RPP prices
  - Application of GA modifier to specified customers
  - Distribution Rate Protection (DRP)
  - First Nations Delivery Credit Program (FNDC)
- All of the credits provided to customers under OFHP are settled with the IESO, and there is no impact on distributors' expenses, revenues and variance accounts.
- Impact on OFHP on cost of power and working capital allowance – New Appendix 2-Z

Accounting Standards

- Utilities were required to make capitalization and depreciation policy changes by January 1, 2013
  - Most of the 2019 applicants last rebased with updated capitalization and depreciation policies.
  - If capitalization and depreciation policies changed since the last rebasing application, identify the changes and the cause of the changes.
- Utilities must have converted to IFRS effective January 1, 2015.
  - Filing Requirements and Chapter 2 Appendices are structured for applicants that adopted IFRS January 1, 2015.
  - Chapter 2 appendices related to IFRS conversion are hidden.
  - Applicants that have not rebased under the amended capitalization and depreciation policies should consult previous filing requirement for guidance or contact OEB staff.

Pensions and OPEBs

- OEB report Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (EB-2015-0040) was issued on September 14, 2017
- The Report establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications.
    - An OEB panel can use another method if accrual accounting does not result in just and reasonable rates.
- The Report also provides for the establishment of a variance account to track the difference between the forecasted accrual amount in rates and actual cash payments made.
- Asymmetric carrying charge in favour of ratepayers applied to the differential.
- Variance account is effective January 1, 2018, unless otherwise ordered by the OEB.

Pensions and OPEBs (contd.) Variance Account

Utilities with approved utility-specific OPEBs variance account:

- Some utilities have an approved variance account with utility specific accounting order. In such cases, the OEB has set rates using the cash method and used the OPEBs variance account to keep these prior periods open to further adjustments pending the outcome of this consultation.
- For distributors with an existing OPEB variance account, the OEB would only consider approving a distributor for the accrual method of pension and OPEB recovery in rates, if the distributor disposes of the existing utility specific variance account.
- The new generic variance account will be effective upon a transition to the accrual method (if approved) as of the date of a utility's next cost-based rate order.
- For detailed accounting guidance please refer to Appendices C and D to the OEB Report.
- Please send us an IRE for further questions.

Changes to PILs model

- No major changes – except there are no more schedules for CEC for any of the years
- Elimination of the eligible capital property rules and introduction of a new class of depreciable property, class 14.1, effective January 1, 2017
- There is a tab for integrity checks in the model.
- Changes in small business taxes have been reflected in the model.

Update to DVA Continuity Schedule for 2019 & Key Clarification Points

- Tabs 2a & 2b
  - New for 2019: The DVA continuity schedule, previously tab 2, has been divided by Group 1 and Group 2 Accounts, now tabs 2a and 2b
- Reversing entries – principal adjustments
  - Must be cognizant of the effect of principal adjustments made to 2016 continuity schedule
  - Reversing adjustment needed to be made in the continuity schedule for the year in which that adjustment was made in the distributor's general ledger (typically subsequent year)
- Class A/B transition customers
  - Transition customers that are allocated a customer specific GA and/or CBR Class B balance are not to be charged the general GA or CBR rate riders. These customers are allocated only a portion of the GA and CBR amounts and are dealt with through customer-specific billing adjustments
- Account 1508
  - Any utility specific 1508 sub-accounts requested for disposition must have supporting evidence showing how the annual balance is derived. The relevant accounting order must be provided

Takeaways from 2018 Applications

- IESO RPP/GA settlement true-ups
  - True-ups should be performed with more frequency (min. quarterly)
  - True-ups were not reflected in the year to which they relate
  - OEB letter dated May 23, 2017, titled Guidance on Disposition of Accounts 1588 and 1589, addressed this

- Embedded generation reporting to IESO impacting GA settlement
  - Embedded generation volumes must be reported correctly to IESO so that the IESO can correctly bill GA amounts

- GA unbilled revenue discrepancies
  - Must accrue unbilled revenues for Class A customers on same basis as costs (based on peak demand factor, should be no variance for Class A)
  - Must accrue unbilled revenues for Class B customers on the same basis as their normal billing rate (1st estimate, 2nd estimate, or actual)

Takeaways from 2018 Applications

- GA pricing by customer class:
  - Must apply same GA rate (1^{st} estimate/2^{nd} estimate/actual) to all customers within the same class
  - Changes to GA rate must be made effective at the start of rate year, not during
- Expected Balances in Accounts 1588 and 1589
  - Distributors settle with the IESO for the differences between amounts billed for energy and amounts paid to the IESO (and subsequently trued-up); Account 1588 balance should be relatively small
  - 1589 balances should be substantiated by GA Analysis Workform
- DVA Continuity for Account 1580 CBR sub-accounts
  - Need to use the 1580 CBR Class A and B sub-accounts appropriately
  - Must not dispose of CBR Class A Balances

Changes to Filing Requirements for 2019

- Additional disclosures regarding Settlement with IESO
  - Billing rates used for GA for each customer class
  - Process for providing consumption estimates for RPP and Non-RPP customers to the IESO; data used to adjust estimates to actuals
  - Explanation of any impact of embedded generation volumes
  - Disclosure of internal control tests used by distributor to validate the consumption figures for RPP and Non-RPP customers (Class A & B)

- Additional disclosures regarding Accounting Practices
  - Explanations of how transactions are initially recorded from IESO bills to general ledger Accounts 1588 and 1589
  - Details of the process used for true-up adjustments to Accounts 1588 and 1589 for various elements that flow to those accounts (revenues and costs)
  - If any Non-RPP Class B customer classes were billed actual GA rates, the distributor must provide a proposal to exclude these customers from calculation of GA rate rider

Changes to Filing Requirements for 2019

- Explanations required for all differences between balances reported in continuity schedule and those reported in RRR

- CBR Class B Dispositions
  - Small balances that do not generate a rate rider (4 decimal places) for CBR will be added to the 1580 WMS control account, rather than disposed to 1595 (as was the case in 2018 rate year)

- Updated GA Analysis Workform and newly issued 1595 Analysis Workform

Supplementary Models to DVAs

- Over last several years, two key areas of focus in DVA balance reviews:
  - Accuracy of balances in Accounts 1588 and 1589
    - GA Analysis Workform added in 2018 rate year
  - Magnitude of residual balances in Account 1595 vintage sub-accounts
    - New 1595 Analysis Workform added for 2019
- Interim disposition will be used on a case-by-case basis for 2019 rate applications

Updates to GA Analysis Workform

- Automated features to reduce completion time and mitigate possible errors
- Multiple years requested for disposition appear on different sheets, same file
- Comprehensive instruction guide
- Preliminary questionnaire regarding GA transactions and balances included as an attachment to reduce number of interrogatories

Account 1595 Residual Balance Disposition

Background

- Account 1595 tracks difference between amounts approved for disposition and amounts collected from/returned to customers
- Balance leftover in 1595 account should be relatively small (difference between projected and actual consumption)
  - Increased number of disposition requests for large residual balances in vintage 1595 sub-accounts
  - Lack of justification for large residual amounts, or
  - Errors identified that required corrections

Account 1595 Residual Balance Disposition

Background, continued

- Sources of errors identified include:
  - Early disposition of account balances before rate rider ceased
  - Incorrectly calculated rate riders used to recover balances disposed
  - Incorrect application of rate riders to customers or customer classes who did not contribute to variances in the account(s)
  - Discrepancies with RRR data submitted by distributors
  - Approved dispositions not transferred to Account 1595 as ordered in decisions

Account 1595 Residual Balance Disposition

New filing requirements for 2019:

- Detailed explanation for material residual 1595 balances
- Completion of new 1595 Analysis Workform

- Workform serves two primary functions:
  - Reasonability check to help distributors explain large balances
  - Locate material discrepancies by rate class and by rider to:
    - focus explanations on underlying causes, or
    - make corrections before final disposition

1595 Analysis Workform

How it works:

- Initially calculates the residual balances at a group level (one group being GA, the other being the remainder of the accounts), and expresses residuals as a % of amounts originally approved for disposition
- *<u>If residual balances for either group are within +/-10% of amounts originally approved, then no further analysis is required by the distributor</u>*. If residuals are greater than +/-10% of amounts originally approved for disposition, the materiality threshold test is exceeded and further analysis is required
- The distributor selects the rate riders applicable for that vintage 1595 sub-account
- For each rate rider, the distributor will enter the data that was used in calculating that rider for each customer class, as approved by the OEB (including allocated balances and projected consumption forecast)

1595 Analysis Workform

How it works, cont.:

- For each rate rider and customer class, the distributor will indicate the actual billed consumption that the rider was applied against. The workform calculates the difference between approved forecasted consumption and actual billed consumption, multiplied by the rider, to determine how much of the residual balance pertains to each customer class and for each rate rider
- The distributor will also enter RRR data for annual consumption by each rate class as a reasonability check to compare against amounts entered in the billed consumption area
- By having the residual balances expressed by rate rider and by customer class, the distributor has the ability to identify the specific underlying drivers of the variance causing a residual balance, and better focus their explanations for why that is the case, or to make the appropriate corrections prior to request for disposition.

Questions?