Orientation Session for Electricity Distributors Rebasing for 2016 Rates

Ontario

AGENDA

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

July 23, 2015		
8:45	Welcome and Meet Your Case Manager	Lynne Anderson
9:00	Striving for Excellence	Ken Quesnelle
9:30	RRFE Debrief - What we have learned from the first two years under the RRFE	Ceiran Bishop
10:00	The Role of The Registrar - What does it mean for the application process - Review of the Board's rules and practice directions	Jennifer Lea
10:30	**Refreshment Break**	
10:45	Filing Requirements - Summary of key changes	Martin Davies
11:30	Consolidated Distribution System Plans - Keys to success	David Richmond
12:00	**Lunch Break (provided)**	
1:00	Load Forecasting - Including the treatment of CDM impacts	Stephen Vetsis
1:30	Cost Allocation and Rate Design - Review of what has changed since last rebasing including the new Rate Design and Street Lighting policies	Stephen Vetsis Vince Cooney
2:15	**Refreshment Break**	
2:30	New policy options for the funding of capital investments - Review of the ACM/ICM policy and the status of the remaining elements of Phase 2	Martin Davies
3:00	Setting Rates using MIFRS - Review of requirements for 2016 filers and Ch. 2 appendices	Raj Sabharwal
3:45	Intervenors' Perspective - How intervenors assess applications	Mark Rubenstein
4:30	Questions on other topics and closing comments	Ceiran Bishop
5:00	End	

		Attendance
1	**Attawapiskat Power Corporation**	
	Rod Reimer	rreimer@ontera.net
2	**Brantford Power Inc.**	
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	Oana Stefan	oanastefan@brantford.ca
3	**Canadian Niagara Power Inc.**	
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4	**Centre Wellington**	
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	Lisa Lin	
5	**Chapleau Public Utilities Corporation**	
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9	**Espanola Regional Hydro Distribution Corporation**	
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10	**Fort Albany Power Corporation**	
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11	**Grimsby Power Incorporated**	
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	Amy La Selva	amyl@grimsbypower.com
12	**Guelph Hydro Electric Systems Inc.**	
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13	**Halton Hills Hydro Inc.**	
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14	**Hydro 2000 Inc.**	
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16	**Kashechewan Power Corporation**	
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17	**Lakefront Utilities Inc.**	
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18	**London Hydro**	
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19	**Midland PUC**	
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	Ken Robertson	

20	**Milton Hydro Distribution Inc.**	
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24	**Thunder Bay**	
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26	**Wasaga Distribution Inc.**	
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28	**Whitby Hydro Electric Corporation**	
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	Cindy Perrin	cperrin@whitbyhydro.on.ca
29	**Woodstock Hydro Services Inc.**	
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30	**Borden Ladner Gervais**	bbacon@blg.com
	Bruce Bacon	

Total: 53

2016 Cost of Service Applications
Case Managers

Distributor	Docket Number	Case Manager [1]
January 1 Rate Year		
Grimsby Power Inc.	EB-2015-0072	Martha McOuat
Guelph Hydro Electric Systems Inc.	EB-2015-0073	Georgette Vlahos
Waterloo North Hydro Inc.	EB-2015-0108	Jane Scott
May 1 Rate Year		
Chapleau Public Utilities Corporation	EB-2015-0060	Martha McOuat
Entegrus Powerlines Inc.	EB-2015-0061	Stephen Vetsis
Espanola Regional Hydro Distribution Corp.	EB-2015-0068	Birgit Armstrong
Halton Hills Hydro Inc.	EB-2015-0074	Martha McOuat
Milton Hydro Distribution Inc.	EB-2015-0089	Harold Thiessen
Renfrew Hydro Inc.	EB-2015-0099	Keith Ritchie
Rideau St. Lawrence Distribution Inc.	EB-2015-0100	Martin Davies
Wasaga Distribution Inc.	EB-20015-0107	Christie Clark
Wellington North Power Inc.	EB-2015-0110	Jane Scott

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

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Orientation Session

Rebasing for 2016 Rates

Ken Quesnelle Vice Chair
July 23, 2015

Objectives of the RRFE

- Shift focus from distributor cost to value for customers
- Better align distributor system reliability and quality of service levels with customer expectations
- Institutionalize continuous improvement and innovation
- Provide for a comprehensive approach to network investments to achieve optimum results
- Better align timing and pattern of expenditures with cost recovery
- Provide a sustainable, predictable, efficient and effective regulatory framework

Aligning Interests

- Customer Focus
  - Services are provided in a manner that responds to identified customer preferences
- Operational Effectiveness
  - Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives
- Public Policy Responsiveness
  - Utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board)
- Financial Performance
  - Financial viability is maintained; and savings from operation effectiveness are sustainable

Key Components of Outcomes Approach

- Good planning and asset management discipline
- Effective consultation and engagement with customers
- Applications that reflect planning and customer input
- Good corporate governance
- Regular reporting and performance monitoring – the scorecard

What does that mean for Applicants?

- The OEB process is the opportunity
- Utility needs to take ownership of it
  - Provide the context, the business environment, the challenges
  - Consult with, inform and be informed by customers
  - Align the information with the ask
- The quality of the result depends on a quality application

Applications Process

- The RRFE set out to accomplish many things
- Is the current applications process “fit for purpose”?
- Does the application process allow for the kinds of discussions that put the best information in front of the OEB members on which to make the decision?
- What works well, what other approaches could be adopted?

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Orientation Session for Cost of Service Applicants

Overview of 2016 Filing Requirements

July 23, 2015

The Renewed Regulatory Framework for Electricity

- The RRFE shifts the focus from utility cost to value for customers
  - Better align utility reliability and quality of service levels with customer expectations
  - Better align timing and pattern of expenditures with cost recovery, including pacing of bill impacts and cost predictability
- The RRFE defined four outcomes
  - Customer Focus
  - Operational Effectiveness
  - Public Policy Responsiveness
  - Financial Performance

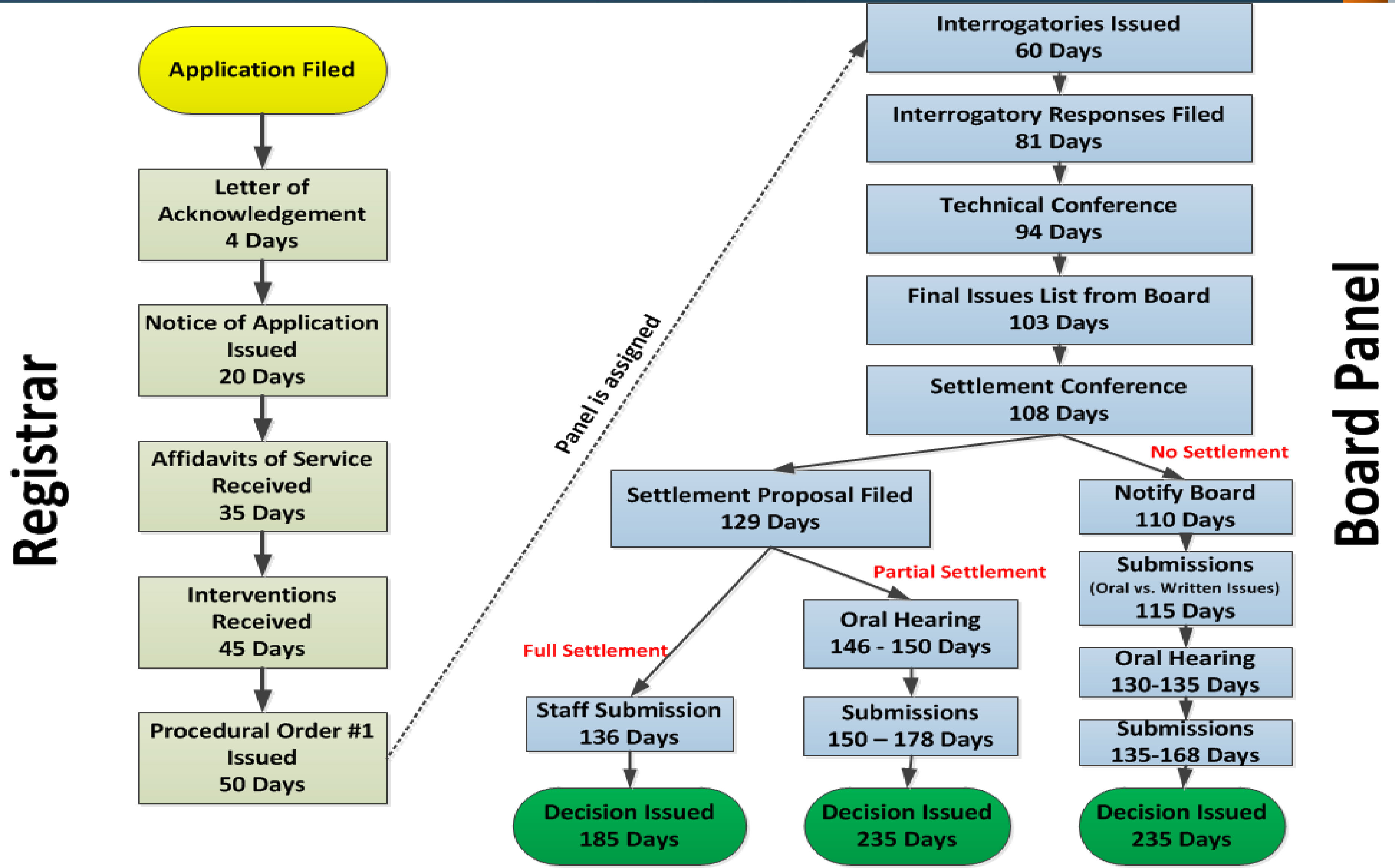
Staff's observations from decisions

- Most 2014 and 2015 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
- Commonly unsettled issues in 2014/5
  - Working capital allowance
  - OM&A
  - Rate design for >50kW
- In one application that went to a full hearing, the OEB found that customer engagement activities going forward should focus on providing customers with more specific information as to the costs of proposals
- In both 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 OEB confirmed that Distribution System Plans need to be stand alone documents

Continuous Improvement in adopting RRFE Lens

- Vision is that business strategies, objectives and priorities of LDCs come to the forefront of the hearing process
- Presentations becoming 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 as well, aim is for procedural steps that lead to a more focussed hearing; evolution continues:
  - Issues list – where does it best fit? Should there be a two stage process?
  - Notice - how to ensure that discrete customer groups are notified
  - Flexible tools – consider non-transcribed TCs, conference calls

Typical Case Timelines



Issues List

- A generic issues list process was implemented for the 2014 EDR process (May 1, 2014 filers). The sequence of the issues list determination was altered in 2015 COS beginning with January filers.

Modification for January 2015 filers:

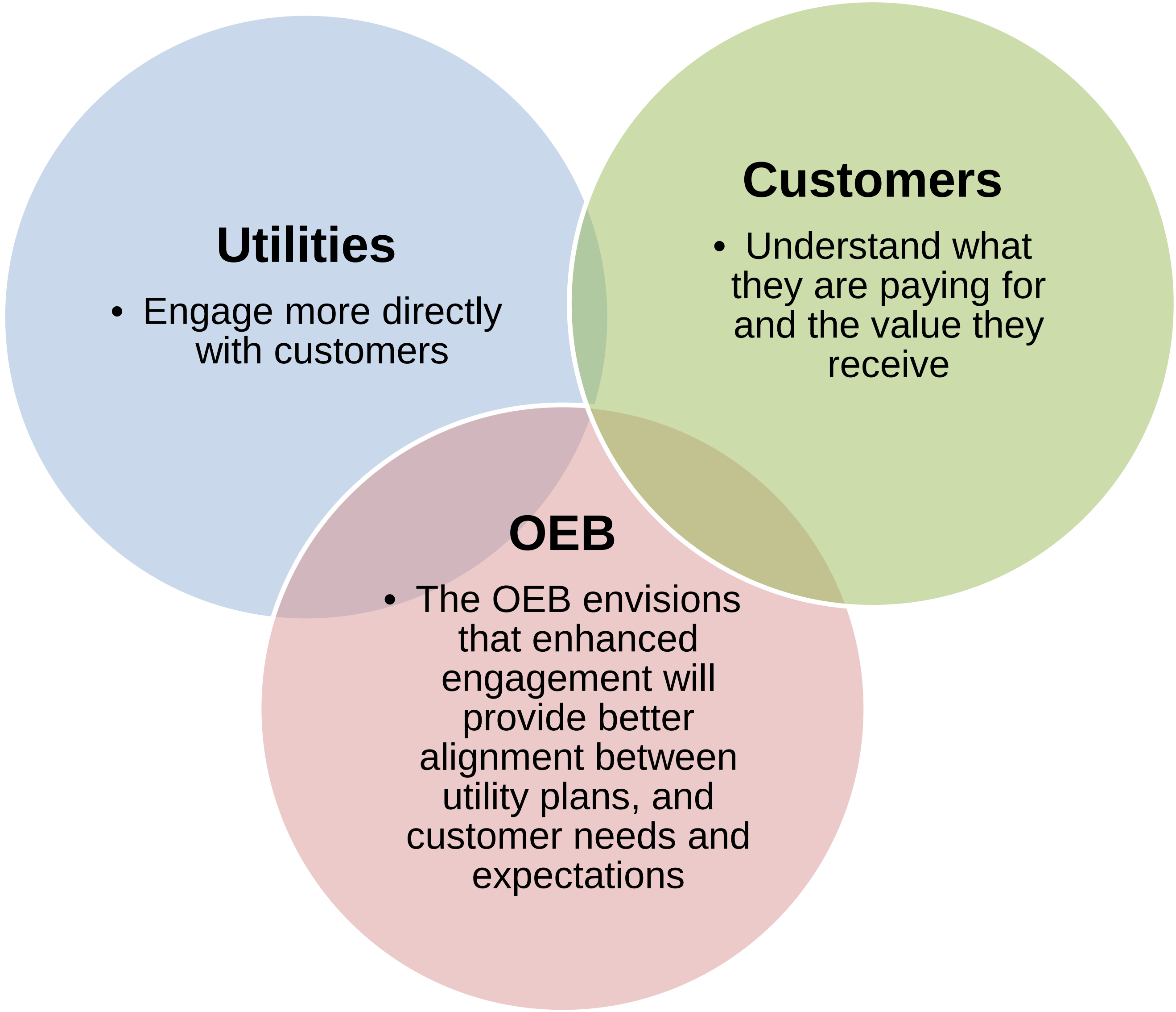
Application submitted → Discovery → Issues List Process → Settlement Conference → Hearing if no full settlement → Decision and Order

- In this approach, OEB staff and the parties agree upon a proposed issues list following a round of interrogatories and a technical conference, if required.

- A proposed issues list is filed with the OEB for approval prior to the settlement conference.

- The goal is to have an issues list that is specific to the application, though certain generic matters may also be at issue.

Customer Focus



Requirement for utilities to engage with their customers

- The OEB requires utilities to demonstrate early and ongoing customer engagement in the development of capital plans and rate proposals
- The Filing Requirements:
  - Overview of customer engagement activities undertaken by a distributor with respect to its plans and any other communication (e.g. bill inserts, town halls)
  - How customer needs have been reflected in the application
  - How customers have been informed about the proposals in the application and the value of those proposals i.e. costs , benefits and impact on rates
  - Any feedback provided by customers and how this feedback shaped the final application

Implementing Customer Engagement

- Goal is not to get guidance on what to do
  - This is management's responsibility
- Rather, ask questions that will get to know your customers
  - Will help you make better decisions, e.g. you can upscale or downscale a project accordingly
  - Not new, distributors have been doing this for years

Sample Customer Engagement Activities among 2014 & 2015 COS Applicants

Event Type	# Distributors
Attendance at Community Events	12
Own Survey	11
Direct Communications (In-Person)	10
Survey by Third Party	9
Re-Designed Website	8
Bill Inserts/E-Mail Blasts	8
Customer Education Seminars	7
Social Media Campaigns	6
Town Hall Meetings	5

Integrated System Planning

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

Rigorous Asset Management Process

- Systematic assessment of asset condition, system operating conditions and service objectives

+

Robust Capital Expenditure Plan

- Integrates system renewal and expansion, regional drivers, smart grid and connection of renewables
- Organized by driver
- 5 year horizon
- Historical context

→

Facilitate Board assessment and LDC delivery of value to customers

- Optimal investments
- Enable performance assessment
- Continuous improvement; customer focus
- Promotion of predictability in rates and affordability for customers

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

Key Recent 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: Process and Overview
  - Session 2: Filing Requirements and DSP
  - Session 3: Load forecast, Cost Allocation and Rate Design
  - Session 4: Advanced Capital Module, Accounting considerations, Intervenors' perspective

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Orientation Session
Electricity Distributors Rebasing for 2015 Rates

The Rules of Practice, the Practice Directions & the Role of the Registrar

Jennifer Lea
Counsel

Agenda

1. Review of Registrar Role
2. Review of updated Rules and Practice Directions
3. Hearing Process
4. Questions

Registrar – Delegated Decision Making

- Routine delegated decision-making
- All applications that are not otherwise delegated under s. 6(1)
  - Issue notice
  - Issue PO#1

Registrar – Delegated Decision Making

- **Notice**
  - Determination of appropriate publication
  - Receive, consider and grant/refuse requests for:
    - Intervenor status
    - Cost eligibility
- **Issue PO#1**
  - Decision with respect to intervenor and cost eligibility requests
  - Set out procedure for hearing up to end of discovery:
    - Guidance on RRFE expectations
    - Intervenor attendance
    - Issues list process following discovery

Registrar – Adjudicative Process

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

Practice Directions and Guidelines

- Rules of Practice and Procedure
- Practice Direction on Confidential Filings
- Practice Direction on Cost Awards
- Settlement Conference Guidelines

All of the above can be found on the OEB's website.

Updated Rules and Practice Directions

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

Key Changes - Rules

PURPOSE	CHANGE	AMENDMENT TO
To improve transparency of and stakeholder access to information on parties that intervene regularly.	Parties file information about their organization and representative(s) for posting on the OEB's website.	*Rules (22.03(b))* *Practice Direction on Cost Awards (3.03.1)*
Provide stakeholders with web-based access to proceedings.	Stakeholders can sign up through the OEB's website to monitor a OEB proceeding.	*Rules (9.03)*
Consistency in information filed when amendments to evidentiary record are made.	**New and explicit requirements with respect to changes to the evidentiary record.**	***Rules (11)***
Ensure a complete record.	Applicant must address the issues raised in letters of comment by way of a document filed in the proceeding.	*Rules (23.03)*

Key Changes – Settlement Conferences

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

Application filed

Check for completeness

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

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

Notice issued

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

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

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

Notice period

Intervention and letters of comment are received

Once publication is complete:

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

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

Testing evidence – typical steps

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

ADR – Settlement proposal

Most cases have an OEB ordered ADR

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

If no ADR – go to submissions.

ADR – Staff's Role

What is New:

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

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

Submissions

Submissions necessary if no full settlement achieved

Typical order of submissions:

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

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

Decision & Draft Rate Order

- Written decision scheduled to be issued – this is the date on the metric on the OEB website.
- A draft rate order must be prepared in accordance with the decision

Steps in review:

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

Oral hearing – additional steps

The following steps may be added in an oral hearing:

- Presentation Day
- Issues conference
- Procedural and motions day
- Pre-hearing conference
- Oral cross-examination
- Oral submissions
- Standard timeline: 280 days

Oral hearing protocol

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

Tips:

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

Questions

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Filing Requirements – Chapters 1 and 2 – 2015 Update

Summary of Key Changes

Martin Davies

July 23, 2015

Chapter 1

- Chapter 1 is general guidance on the filing of all types of electricity distributor applications
- No substantive changes

Chapter 2 – Key Changes

- Updates for Policy Changes
- Key Additions to Existing Sections
- New Sections Added
- Treatment of REG Investments

Updates for Policy Changes

- Allowance for Working Capital (2.2.1.3)
  - to reflect new default value of 7.5% outlined in OEB letter of June 3, 2015
- New Policy Options for the Funding of Capital (2.2.2.6)
  - to reflect issuance of OEB Report of September 18, 2014 outlining the new Advanced Capital Module
  - Work on half year rule still ongoing with KPMG and working group
- Service Quality and Reliability Performance (2.2.2.8)
  - Revised wording to reflect new policy on targets
- Low-income Energy Assistance Programs (LEAP) (2.4.3.6)
  - statement that LEAP program and funding will continue in tandem with the Ontario Energy Support Program that will be in place effective January 1, 2016

Updates for Policy Changes (con't)

- Cost Allocation (2.7)
  - changes to reflect the OEB's letter relating to changes in approach to street lighting cost allocation and related areas
- Rate Design Policy (2.8.2)
  - to reflect issuance of OEB Report of April 2, 2015 outlining the transition to be implemented by electricity distributors to a fully fixed monthly delivery service charge for residential customers
  - Implementation of a fixed charge for other new distributor specific charges (e.g. ICM, Group 2 DVAs, etc.)
- Global Adjustment Account (2.9.7.1)
  - Same amendments as for Chapter 3 for IRM applications to require additional filings because of issues arising with Account 1589 $RSVA_{Global\ Adjustment}$

Update To Working Capital Allowance (WCA) Policy (1)

- On June 3, 2015, the OEB issued a letter stating that effective immediately, the WCA default value was 7.5% in place of the previous 13%

- Reason for the change is that it had become apparent to the OEB that average working capital requirements have been lowered as a result of a number of technical changes that reduce the actual time between service provision and payment including:
  1. The substantial completion of the smart meter rollout and advanced metering infrastructure, which includes aggregate meter reading time;
  2. Wider adoption of monthly billing, resulting in a shorter period from service to payment;
  3. CIS updates which reduce time required to calculate customer bills;
  4. General Process Improvements.

Update To Working Capital Allowance (WCA) Policy (2)

- As previously, distributors not wishing to use the default value can request approval for a distributor-specific WCA supported by the appropriate evidence from a lead-lag study or equivalent analysis
- For the Custom IR application option, distributors are expected to file robust evidence of costs and revenues and it is therefore reasonable to expect distributors choosing this option to file evidence in support of their requested working capital allowance, rather than the use of a default value
- While the use of the default value will no longer be applicable to Custom IR applications, given the timing of this new policy, distributors that have filed a Custom IR application for rates effective January 1, 2016 may use the 7.5% default value to calculate their WCA rather than file a lead-lag study as part of their application

Global Adjustment Account (1)

- A distributor must provide a description of its settlement process with the IESO or host distributor, including:

1. specification of the GA rate it uses when billing its customers (1st estimate, 2nd estimate or actual) for each rate class;

2. Itemization of its process for providing consumption estimates to the IESO;

3. Description of the true-up process to reconcile estimates of RPP and non-RPP consumption once actuals are known. This should detail the method for estimating RPP and non-RPP consumption as well as its treatment of embedded generation or any embedded distribution customers.

Global Adjustment Account (2)

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

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

- A distributor with such a newly Class A-eligible customer should also propose an appropriate allocation for the recovery of the global adjustment variance balance based on its settlement process with the IESO or host distributor for any residual GA variance balances that might have accrued prior to those customers being classified as Class A customers

Key Additions to Existing Sections

- Scorecard Performance Evaluation (2.0.5)
  - requirement added to explain the drivers for a distributor's performance
- Executive Summary (2.1.2)
  - new requirement to separately identify all proposed changes that will have a material impact on customers including any changes to rates and charges that may affect discreet customers or groups of customers including specification of which customers will be impacted by which changes
- Accounting Standards (2.0.4)
  - statement that applications from distributors filed under CGAAP will no longer be accepted
- Administration (2.1.6)
  - changes made to reflect new notice process
- Capital Expenditures (2.2.2)
  - strengthening of statement that all elements of the Distribution System Plan must be contained in one integrated and cohesive stand-alone document
- Rate Mitigation (2.8.13)
  - discussion added as to expectations of distributors in dealing with the impact on residential customers of shift in rate design to fully fixed rates

New sections Added

- Notional Debt (2.5.2)
  - clarification of Notional Debt (difference between distributor and OEB-deemed debt)
- Stand-by Rates (2.7.1)
  - final approval of interim charge may be sought though confirmation must be provided that all affected customers have been advised
  - changes in the rate and/or methodology may also be requested

Treatment of REG Investments

- With a Cost of Service Application, a distributor is required to file a Distribution System Plan (DSP), which includes Renewable Energy Generation (REG) investments
  - Prior to filing a DSP a distributor must submit relevant REG information to the IESO and request that the IESO provide a letter commenting on the information (which becomes part of the DSP filed in the rates case).

- A Chapter 5 filing should include single/multi-year REG investments (as applicable), including the Direct Benefit portion for OEB approval:
  - Renewable Enabling Improvements (REI) 6%
  - Renewable Expansions (RE) 17%
  - Or file a study to establish a custom percentage.

- the rate protection amounts approved for recovery will be through the IESO

- Appendix 2-FA, 2-FB and 2-FC to be completed

Questions?

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Orientation Session
Electricity Distributors' Rebasing for 2016 Rates

Consolidated Distribution System Plans

Keys to Success

David Richmond
July 23, 2015

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 (RRF) Report of October 18, 2012.

- In that report it was stated that:
  - LDCs are required to file five year capital plans to support their Rates applications
  - 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

Introduction and Background (cont'd)

- The OEB's RRF Report stated that the DSPs should utilize an asset management and structured investment planning approach

- 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

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 and CDM requirements been met?)
- Financial Performance (Is the financial performance appropriate and is it sustainable?)
- Any other LDC specific outcomes as appropriate

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.

Things that have Gone Well

- 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

Opportunities for Improvements

- More power system equipment could be covered by the Asset Condition Assessment process
- Greater inclusion of OM&A spending levels and trends should be considered in the overall expenditure optimization
- There could be further efforts to rank new discretionary investments.
- There should be more performance level tracking to determine if the proposed investments result in commensurate improvements in performance or efficiency
- 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
- The Customer Engagement process could be more robust with more examples of what was considered/rejected and why

Thank You

QUESTIONS

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

Orientation Session
Electricity Distributors Rebasing for 2016 Rates

Load Forecasting

July 23, 2015

Table of Contents

Significance of Load Forecasting in Cost of Service Applications

- Establish the sales volumes for the test period:
  - Number of customers
  - Consumption of customers (kWh)
  - (Peak) Demand of customers (kW)
- The drivers differ by classes of customers (Residential, GS < 50 kW, etc.)
- Used as allocators for recovery of costs from different customer classes
- Also used as the billing determinants for determining fixed and variable rates and for other rate riders
- Sales volumes (customers, kWh, kW) factors into revenue sufficiency/deficiency
- 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.

Changes to Load Forecasting Resulting from Rate Design Projects

- The OEB has announced new options for distribution rate design
  - Transition to 100% fixed monthly service charge to be phased in by 2019 for residential customers
  - Initiated review of rate design/revenue decoupling for non-residential customers
- The outcome will affect the impact of load forecasting in rate applications, but the need for load forecasts remains
  - 4-year phase in for residential rate design
  - Demand informs capital and operating programs and costs
    - Expected demand
    - System capacity and reliability

Forecasting Number of Customers

- Utilities have historical data on number of customers / connections by class
- Historical trends and levels generally an adequate basis for forecasting future growth
  - e.g. average annual growth rate (geometric mean), by customer class
  - Most utilities (and the communities they serve) have stable growth rates of about 0% to 2% per annum
- Adjustments may be made for unique growth patterns in individual classes, movement between customer classes, or changes in customer class definitions
  - Generally done for classes with smaller customer numbers and specific load profiles and demand (e.g. Large Use, Intermediate, Sentinel Lighting)

Forecasting Demand and Consumption - Approaches

- Normalized Annualized Consumption (NAC)
- Multivariate Regression (system purchased kWh)
- Multivariate Regression (by customer classes)
- Combination of these approaches seen beginning in 2013 cost of service applications
- Other approaches?

Forecasting Demand and Consumption

- Utilities generally forecast purchased consumption (kWh)
  - Purchases available monthly from IESO bills; customer billed demand often not available for a calendar month due to billing cycles
    - TOU data provides for calendar monthly data, but will need several years to collect sufficient data.
- Purchased kWh converted to billed kWh through loss factor
  - Purchased kWh = Billed kWh * (1 + loss factor)
- Estimated purchased kWh then allocated to customer classes based on historical patterns
- Weather sensitivity applied to certain classes (typically Residential and GS < 50 kW)
- For demand-billed customers, purchased kW derived from estimated purchased kWh by class conversion factor
- 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?		
August 2003 Blackout, 2013 Ice Storm	Binary flag variables for blackout or reduced consumption due to storm damage. As needed	-ve

Regression Output - Example

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.979498096
R Square	**0.959416519**
Adjusted R Square	**0.957640992**
Standard Error	2599144.111
Observations	168

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	2.55528E+16	3.6504E+15	540.3558299	7.6408E-108
Residual	160	1.08089E+15	6.75555E+12		
Total	167	2.66337E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-90392763.89	8420661.724	-10.73463902	1.37481E-20	-107022741.6	-73762786.21	-107022741.6	-73762786.21
Heating Degree Days	28385.21457	1222.256206	23.22362073	4.06933E-53	25971.37893	30799.05022	25971.37893	30799.05022
Cooling Degree Days	180663.8591	12686.48852	14.24065129	3.01994E-30	155609.2936	205718.4246	155609.2936	205718.4246
Ontario Real GDP Monthly %	178921.2574	63156.91427	2.832963888	0.005205712	54192.57116	303649.9437	54192.57116	303649.9437
Number of Days in Month	1999057.103	265489.4682	7.52970397	3.50381E-12	1474741.548	2523372.658	1474741.548	2523372.658
Spring Fall Flag	-2056228.894	532917.4883	-3.858437636	0.000165158	-3108688.454	-1003769.334	-3108688.454	-1003769.334
Number of Customers	1840.232909	213.4496505	8.621391064	6.11717E-15	1418.690869	2261.774949	1418.690869	2261.774949
Number of Peak Hours	57334.26505	13188.35313	4.347340754	2.4426E-05	31288.56635	83379.96374	31288.56635	83379.96374

Source: Waterloo North Hydro, 2011 EDR (CoS) [EB-2009-0144]

- High R^2
- Significant Regression
- All variables have coefficients with correct signs and are statistically significant at 95% c.i.

Regression Output – Analysis

- t-statistics of variables significant
  - ~ 1.96 for two-tailed test @ 95% c.i.
  - ~ 1.65 for one-tailed test @ 95% c.i.
- Variables have coefficients of appropriate signs?
  - e.g., +ve CDM, -ve Income, -ve HDD or CDD are unintuitive
- F-statistic
  - Overall significance of fit of the model
- R^2 and Adjusted R^2
- Analysis of Forecasts and Residuals
  - Residuals and Mean Absolute Percentage Error (MAPE) should be evaluated based on periodicity of model (e.g. monthly)
  - Patterns in residuals?
    - May be indicative of omitted variables

2.6.2 – Load Forecast Variance Analysis

- Check on the accuracy of the distributor's past load forecasts
- Variance analysis for customers/connections, kWh, kW, revenues:
  - 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-IA must be filled out

	2012 Board Approved	2012	2013	2014	2015 Bridge	2016 Test
Rate Class 1						
# of Customers						
kWh						
kW						
Variance Analysis						
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

Rate Class 2						
# of Customers						
kWh						
kW						
Variance Analysis						
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

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)
  - New 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 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 2016, the OEB must approve:
  - 2016 test year load forecast, including the persistence of historical 2011-2014 CDM programs, and expected 2015 and 2016 CDM programs impacts on the 2016 test year load forecast; and
  - Corresponding amounts used for establishing the 2016 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 from 2011 to test year on the test year load forecast
- CDM adjustment on load forecast must recognize the following:
  - “real” 2016 CDM program impact on 2016 demand is less than annualized (½ year rule used as default)
  - 2011-2014 CDM program impacts are captured, in some form, in historical actuals
  - CDM adjustment is the additional impact beyond what is in the base forecast and reflecting that first year CDM program impacts are <u>not</u> full annualized impact as reported by the IESO

Appendix 2-I (Load Forecast CDM Adjustment Work Form)

- Spreadsheet first used in interrogatories in 2013 cost of service applications to use results to data and to derive the related amounts for the LRAMVA and the CDM adjustment
- Updated for 2014 and 2015 Cost of Service applications
- Appendix 2-I updated for 2016 Cost of Service Applications
  - 2014 last historical actual is last year of 2011-2014 CDM program, but only includes ½ year impact of 2014 CDM programs
  - New 2015-2020 CDM program through Ministerial Directive to OPA (now IESO) and OEB in March 2014

Appendix 2-I - Outputs

kWh	2011	2012	2013	2014	2015	2016	Total for 2016
Amount used for CDM threshold for LRAMVA (2014)	9,500.00	11,000.00	7,800.00	9,749.00			
CDM adjustment for test year forecast (per Board Decision in distributor's most recent Cost of Service Application) (enter as negative)	- 8,000.00	- 8,000.00	- 8,000.00	- 8,000.00			
Amount used for CDM threshold for LRAMVA (2016)				-	20,833.33	20,833.33	41,666.67
Manual Adjustment for 2016 Load Forecast (billed basis)	-	-	-	4,874.50	20,833.33	10,416.67	36,124.50
Proposed Loss Factor (TLF)	3.25%	Format: X.XX%					
Manual Adjustment for 2016 Load Forecast (system purchased basis)	-	-	-	5,032.92	21,510.42	10,755.21	37,298.55

- Outputs from Appendix 2-I calculate the amount to be used for the LRAMVA and the related but different number for the CDM adjustment to the load forecast
- If the base forecast is on a system purchased basis, then the loss-adjusted amount should be used; otherwise the billed CDM adjustment is used
- The distributor must allocate the amounts for the LRAMVA and CDM adjustment to customer classes on a reasonable basis

Questions?

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

Orientation Session – 2016 Rates

Cost Allocation and Rate Design

Stephen Vetsis, Advisor, Electricity Rates and Prices

July 23, 2015

Agenda

- Cost Allocation
  - Policy Review (changes since 2012)
  - Policy impacts on filings
  - Cost Allocation Filings
    - Cost Allocation Model (changes)
      - V2 to V3.3
- Rate Design
  - Transition to fully fixed rates for residential class
  - Implementation details
  - Exceptions and approaches to mitigation

Cost Allocation Policy: Your Last Filing (2012)

- OEB had just issued Report of the Board: “Review of Electricity Distribution Cost Allocation Policy”, EB-2010-0219, March 31, 2011
- Cost Allocation Model was updated to v2.0 to implement changes.
- Changes required by report:
  - 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)
- Deferred for study and future development:
  - Allocation by Host Distributor to Embedded Distributor(s)
  - Unmetered Loads (EB-2012-0383; Board report Dec. 2013)
  - Load Displacement Generation (EB-2013-0004)

Allocation by Host Distributor to Embedded Distributor

Memo to distributors, July 16, 2013 addressed this issue

If Separate Embedded Distributor Class, then

- No change to policy
- Continue to use CA Model and Appendix 2-P
- Appendix 2-Q is a useful framework, but not required to file

Else, Embedded Distributors subsumed in a GS Class

- Include as a customer of the class in data inputs: customer count, load forecast, revenue, etc.
- You <u>must</u> file Appendix 2-Q, though full detail not required

Allocation by Host Distributor to Embedded Distributor

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- You <u>must</u> file Appendix 2-Q, though full detail not required

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

CA Policy Review: 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

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: 2012-2016

- **Exhibit 7, then and now:**
  - Summary description, highlighting rebalancing (if any)
  - Similar to 2012

- **Appendix 2-P**
  - Provides summary tables for results of cost allocation study and proposed changes/rebalancing

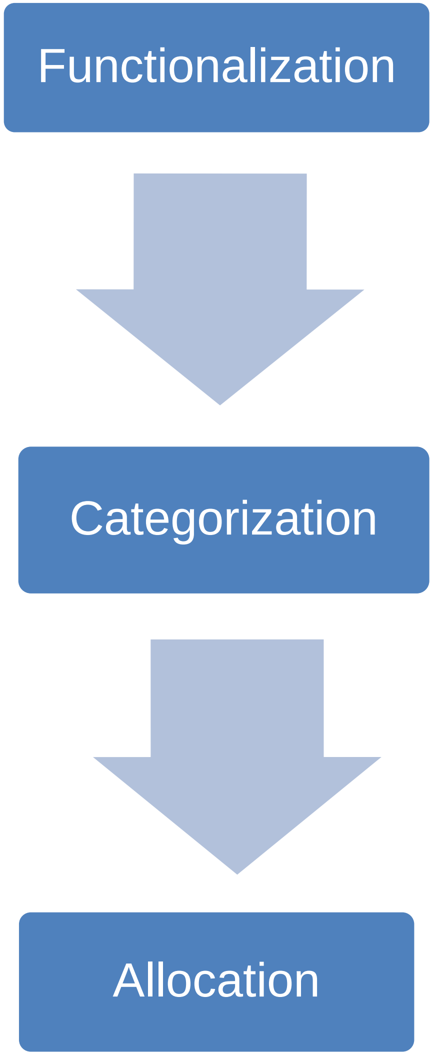
- **Appendix 2-Q**
  - Provides sharper focus on embedded distributor(s) than CA Model
    - Information required of host distributor, if no separate class of embedded distributor(s)

- **CA Model, then and now**
  - Similar to V2 (2012)
  - Incorporates policy changes as a result of EB-2010-0219 and EB-2012-0383
  - Includes more instructions reflecting experience in other applications

Cost Allocation Framework

Conceptual Framework unchanged, basic CA Model little changed

- Customer Classes: worksheet I2
- Functionalization
  - Preparing USoA account forecast data
  - Worksheets: I-3 (trial balance forecasts); I-4 (asset sub-accounts where required)
- Categorization:
  - Accounts by demand-related, customer-related, partial (min. system)
  - Worksheets: E1; I-5.1 cell D21
- Allocation:
  - Allocator for each account: policy effected in worksheet E-4
  - Allocator values (allocation to all classes adds to 100%): worksheet E-2
  - Data Input: worksheets I-5, I-6, I-7, I-8, I-9
  - Detailed calculations: worksheets O-4, O-5, O-6, O-7
  - Main results: worksheets O-1, O-2
  - Other results: O-2.1 – 2.5; O-3.1 – 3.5
  - microFIT unit cost (worksheet O-3.6) new with version 3.0



Rate Rebalancing (Appendix 2-P)

- Applicant provides Appendix 2-P:
    1. Approved revenue-to-cost ratios
    2. Status quo ratios
    3. Proposed ratios

- Policy is unchanged: if any status quo ratio is outside the Board's policy range, proposed rates must adjust to produce a ratio in the applicable range

- Applicant may propose:
    - movement within range
        - expected outcome: direction of any movement is toward 100%
    - movement to include subsequent (IRM) years to mitigate impacts
        - proposed and approved as part of the COS proceeding

CA Model: version 3.1 vs. 2.0

Version 3.0

- 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: version 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

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."
- Rate Design Working Group (RDWG) was formed to gather recommendations for implementation

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

Implementation Details

- Method for calculation is reflected in Appendix 2-PA. and IRM rate generator model.
    - For IRM: Base the change on billing determinants from last COS to ensure calculations are revenue neutral
    - For COS: Use billing determinants from proposed load forecast.
- For any <u>distribution-specific</u> volumetric riders, such as ICM:
    - Adopt fixed-only riders going forward for residential class
    - No change to current riders (i.e., any multi-year rider set in a past case)
    - 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
- No expected changes to method for LRAM/LRAMVA calculations –
    - The balances accumulated in the LRAMVA will decline as the amount of kWh based distribution revenue decreases
- Identical rate design treatment must be applied for any seasonal residential classes.

Triggers for Mitigation/Exceptions

Two scenarios where a mitigation plan is required:

- **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

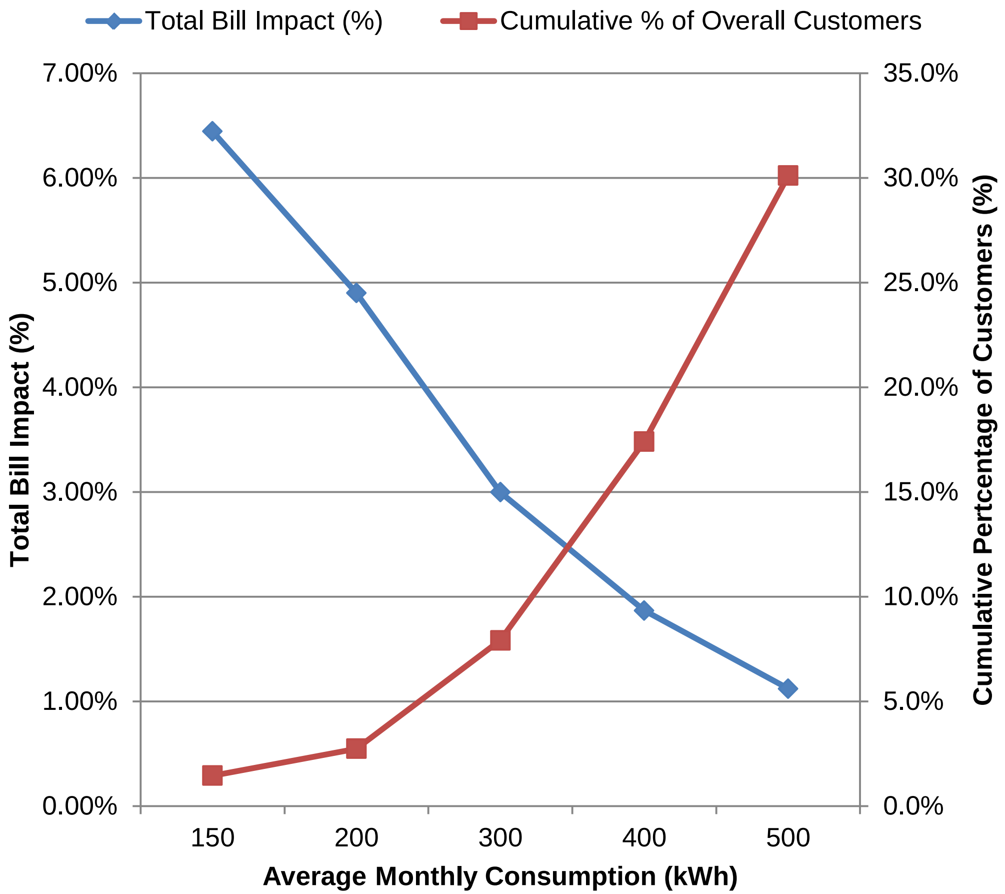
Triggers for Mitigation/Exceptions

- **Second scenario:** if an unusually large total bill impact arises when including impacts of all other changes in application. This considers other drivers of distribution rates in addition to the policy.

- Typical 800 kWh customer cannot be used to assess combined effects because bill impact of rate design change is minimal near average usage levels. (The reduction in variable rate offsets increase in fixed rate).

- Therefore, bill impact evaluation needs to be based on a low-consumption customer.

- Selection of standard “low-volume” customer must balance reality that there are fewer customers as consumption decreases, but distribution bill impacts for these customers are proportionally more significant.



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)

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

Orientation Session
Electricity Distributors Rebasing for 2015 Rates
The Advanced Capital Module

July 23, 2015

Contents

- Phase 1 work
- Advanced Capital Module
- Phase 2 work

New Policy Options for the Funding of Capital Investments (EB-2014-0219) – Phase 1

- Initiated June 20, 2014

- Advanced Capital Module (ACM) and ½ Year Rule
  - Invited working group of utilities, intervenors
  - Provided feedback on concepts of ACM and D_1 –factor

- In August, the OEB decided to proceed with the ACM

- *Report of the Board on New Policy Options for the Funding of Capital Investments – The Advanced Capital Module*
  - Issued September 18, 2014
  - Accompanying Spreadsheet applicable for ACM pre-testing in Cost of Service and ACM/ICM rate rider calculations in Price Cap IR applications.

Summary of Capital Modules

Capital Modules	Cost of Service Application	Price Cap IR Year (in which the capital project goes into service)	Next Cost of Service Application
ACM (Advanced Capital Module)	• Identify discrete projects in DSP which may qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information. • Provide preliminary calculation of materiality threshold based on information in cost of service application.	• Update materiality threshold based on current information to confirm that the project continues to qualify for ACM treatment. • Provide means test calculation and explanation if overearning in last historical actual year. • If costs are less than 30% above what was documented in the DSP, explain differences in cost forecasts from DSP forecast. • Explain any differences in project timing. • If costs are 30% or more above what was documented in the DSP, re-file business cases as new ICM if seeking recovery of incremental costs. • In all cases, explain any significant differences in capital budget forecast from DSP forecast. • Provide incremental revenue requirement calculation and proposed ACM rate riders.	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable). • Based on above, the OEB may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV.
ICM (Incremental Capital Module)	• Not applicable	• Provide explanation for any ICM that could not have been foreseen or sufficiently planned as part of DSP. • Establish need for and prudence of proposed projects. • Provide materiality threshold calculation. • Provide means test calculation and explanation if overearning in last historical actual year. • Provide incremental revenue requirement calculation and proposed ICM rate riders. • Explain significant differences in capital budget forecast from DSP forecast.	• Same as above

How the ACM and ICM Work

Cost of Service Application

- Distributor completes ACM module under Cost of Service
- Projects in DSP that would potentially qualify for incremental capital treatment and cost recovery are identified for all forecasted Price Cap IR years
- Need for, nature, and overall pacing and prioritization of ACM projects over the 5-year term are tested during cost of service
- OEB will pre-determine qualifying ACM projects, but amounts and rate riders not approved in CoS decision

ACM table in cost of service application

Identify ALL Proposed ACM projects and related CAPEX costs in the relevant years

	Test Year	Year 1	Year 2	Year 3	Year 4
Distribution System Plan CAPEX					
Materiality Threshold		$ -	$ -	$ -	$ -
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ -	$ -

Project Descriptions:	**Test Year**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Total**
MTS#2						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
Total Cost of ACM Projects	$ -	$ -	$ -	$ -	$ -	$ -
Maximum Allowed Incremental Capital		$ -	$ -	$ -	$ -	$ -

How the ACM and ICM Work

Price Cap IR application

- Distributor applies for pre-qualified ACM and for any new ICM projects
  - Recalculates materiality threshold based on current information
  - Updates cost estimates and hence qualifying incremental capital for ACM/ICM treatment
  - Proposes rate riders to recover revenue requirement for incremental capital
- Distinction between ACM and ICM
  - Pre-qualified ACM project – nature, need for project not re-tested. Materiality threshold, cost projections and recovery updated. Further explanation only if timing or significant change in cost projections
  - ICM – nature and need for project, as well as materiality threshold, costs and cost recovery tested in Price Cap IR (no change from previous policy)

How the ACM and ICM Work

Next Cost of Service Application

- Review of costs for executed ACM/ICM projects
- Variances between:
  - Estimated and projected costs
  - Rate rider revenues and incremental revenue requirement based on actual costs
- OEB panel will determine if true-up between rate rider revenues and incremental revenue requirement is necessary
- ACM/ICM capital additions included in fixed assets based on actual costs

Other Matters in the ACM Report

- ICM Option only available to distributors under Price Cap IR; not available for distributors under Annual IR or Custom IR
  - Exception: New MAADs Guideline posted March 18, 2015 states that the ICM is available for consolidating distributors who elect to stay out for up to ten year post MAADs
    - If a consolidating distributor was under Custom IR, then it will be under Price Cap IR when the Custom IR plan ends
    - A consolidating distributor under Custom IR may apply for an ICM but must demonstrate that its ICM is outside of the capital plan and budget approved in the Custom IR plan
- No changes to materiality threshold calculation at this time
- No changes to Half-year Rule (e.g. D_1-factor) at this time

New Policy Options for the Funding of Capital Investments (EB-2014-0219) – Phase 2

- OEB staff commenced Phase 2 work in October
- KPMG retained to do an independent review of:
  - How working capital requirements are established for rate setting in other jurisdictions
  - Rate-setting treatment of capital additions in first year of service (i.e. ½ year rule, full-year depreciation, etc.)
  - Modelling and analysis of:
    - ½ year rule on adequacy of recovery of costs for capital additions through cost of service and Price Cap IR term
    - Materiality threshold (deadband and growth) on funding for incremental capital during Price Cap term

New Policy Options for the Funding of Capital Investments (EB-2014-0219) – Phase 2

- Working group of invited distributor and intervenor representatives
- Working group sessions held on April 30 and June 15
- Follow-up analysis by KPMG and OEB staff
- Results of KPMG and OEB staff's work and working group feedback being reviewed by the OEB

Questions?

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

Orientation Session
Electricity Distributors Rebasing for 2016 Rates

Setting Rates Using Modified International Financial Reporting Standards (MIFRS)

Raj Sabharwal, Project Advisor, Electricity Rates and Accounting
July 23, 2015

Agenda

1. Accounting Standards
2. Capitalization and Depreciation Policy Changes
3. Adoption of IFRS
4. Appendices to File in Application
5. Review of Specific Chapter 2 Appendices
   – Fixed Asset Continuity Schedules and Depreciation Expense
   – Account 1575, 1576, 1508
6. Questions

Accounting Standards

- Filing Requirements and Chapter 2 Appendices are structured for applicants adopting IFRS January 1, 2015
- Accounting Standards used in rate applications include:
  - International Financial Reporting Standards (IFRS) as set out in Part I of the CPA Canada Handbook – Accounting (Handbook)
  - Accounting Standards for Private Enterprises (ASPE) as set out in Part II of the Handbook
- The OEB may permit utilities to use US GAAP. Utilities must request prior approval from the OEB
- Applications using other accounting standards (such as Canadian GAAP standards applicable in prior years) will not be accepted

Accounting Standards (contd.)

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 & 7

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)

- The changes made in 2012 or 2013 should be reflected prospectively for 2016 rates

Capitalization Policy

- File capitalization policy, including changes to that policy since the last rebasing application.
  - Identify if and how the capitalization policy changed since the last rebasing application as a result of the OEB letter dated July 17, 2012 or for any other reason subsequent to the changes as per the OEB letter

Capitalization of Overhead

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

Capitalization and Depreciation Policy Changes (contd.)

Example for illustration purposes only

Appendix 2-D

Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2012 Historical Year	2013 Historical Year	2014 Historical Year	2015 Bridge Year	2016 Test Year
Cost Driver #1	$ 100,000	$ 150,000	$ 160,000	$ 175,000	$ 180,000
Cost Driver #2	$ 13,000	$ 14,500	$ 16,000	$ 15,000	$ 15,000
Cost Driver #3	$ 250,000	$ 240,000	$ 260,000	$ 280,000	$ 287,000
Cost Driver #4	$ 170,000	$ 170,000	$ 172,000	$ 175,000	$ 176,000
Total OM&A Before Capitalization (B)	$ 533,000	$ 574,500	$ 608,000	$ 645,000	$ 658,000

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2012 Historical Year	2013 Historical Year	2014 Historical Year	2015 Bridge Year	2016 Test Year	Directly Attributable? (Y/N)	Explanation for Change in Overhead Capitalized
employee benefits	$ 55,000	$ 62,000	$ 60,000	$ 65,000	$ 70,000	Y	No change in capitalization of employee benefits incurred on direct labour used to construct capital assets
costs of site preparation							
initial delivery and handling costs							
costs of testing whether the asset is functioning properly							
professional fees	$ 16,000	$ 20,000	$ 14,500	$ 13,000	$ 11,000	Y	No change in capitalization of professional fees directly related to construction of plant
costs of opening a new facility							
costs of introducing a new product or service (including costs of advertising and promotional activities)							
costs of conducting business in a new location or with a new class of customer (including costs of staff training)							
administration and other general overhead costs	$ 23,000	$ 25,000				N	General overhead costs (e.g. executive management salary allocation not directly attributable to construction of new plant
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ 94,000	$ 107,000	$ 74,500	$ 78,000	$ 81,000		

% of Capitalized OM&A (=A/B)	18%	19%	12%	12%	12%		

Capitalization and Depreciation Policy Changes (contd.)

- 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
  - Must explain if service life is outside of the minimum and maximum TUL in the Kinectrics study
- File depreciation policy or a written description of the depreciation practices followed and used in preparing the application:
  - Must provide a summary of changes to depreciation policy made since the last cost of service filing
  - If further depreciation expense policy changes or changes in asset service lives are made subsequent to those made by January 1, 2013, the applicant must identify the changes and provide a detailed explanation for the causes for the changes

Adoption of IFRS

- Accounting Standards Board extended the deferral of the mandatory adoption of IFRS to January 1, 2015
- Assuming that applicants adopt IFRS January 1, 2015, applications are expected to be filed under MIFRS for the test year.
  - CGAAP applications are not expected.
- Transition year must be presented using MIFRS and may be required to be presented using CGAAP as well.
- Presentation of historical years will depend on timing of adoption of mandatory policy changes.

Adoption of IFRS (contd.)

MIFRS in Rate Applications

- 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)
  - Accordingly, applicants must identify financial differences and resulting revenue requirement impacts arising from the adoption of MIFRS as compared to CGAAP prior to capitalization and depreciation policy changes

Adoption of IFRS (contd.) – Summary of Impacts on Revenue Requirement

Closing NBV for 2015 & 2016 must agree to App 2-BA Fixed Asset Continuity Schedule

Appendix 2-Y

Example for illustration purposes only

Summary of Impacts to Revenue Requirement from Transition to MIFRS

Revenue Requirement Component	2016 MIFRS	2016 CGAAP without policy changes	Difference	Reasons why the revenue requirement component is different under
Closing NBV 2015	$ 65,000,000	$ 66,000,000	-$ 1,000,000	
Closing NBV 2016	$ 68,000,000	$ 70,500,000	-$ 2,500,000	
Average NBV	$ 66,500,000	$ 68,250,000	-$ 1,750,000	Difference is due to changes in capitalization policies & depreciation policies in 2012
Working Capital	$ 1,300,000	$ 1,250,000	$ 50,000	Difference is due to differences in OM&A as outlined below
Rate Base	$ 67,800,000	$ 69,500,000	-$ 1,700,000	
Return on Rate Base	$ 4,407,000	$ 4,517,500	-$ 110,500	Return on rate base is calculated as Rate Base X 6.5% WACC. Difference on return on rate base is due to differences in rate base as noted above
			$ -	
OM&A	$ 13,500,000	$ 12,800,000	$ 700,000	Difference is due to changes in capitalization policies in 2012 and changes in OPEB expense due to adoption of IFRS
Depreciation	$ 5,011,000	$ 5,505,000	-$ 494,000	Difference is due to the changes in depreciation policies in 2012
PILs or Income Taxes	$ 500,000	$ 685,000	-$ 185,000	Difference is due to the differences caused by accounting changes
			$ -	
Less: Revenue Offsets	-$ 1,080,000	-$ 1,080,000	$ -	
			$ -	
			$ -	
			$ -	
Insert description of additional item(s) and new rows if needed.			$ -	
Total Base Revenue Requirement	$ 22,338,000	$ 22,427,500	-$ 89,500	

Total Base Revenue Requirement must agree to the RRWF

Appendices to File in the Application

- Two scenarios are generally expected:

			Accounting Policy Changes in 2012 and Adopted IFRS in 2015	Accounting Policy Changes in 2013 and Adopted IFRS in 2015
			(Date of Transition to IFRS 2014)	
Information to be filed in 2016 CoS Application	2016	Test	MIFRS	MIFRS
	2015	Bridge	MIFRS	MIFRS
	2014	Historical	MIFRS and Revised CGAAP*	MIFRS and Revised CGAAP*
	2013	Historical	Revised CGAAP	CGAAP and Revised CGAAP
	2012	Historical	CGAAP and Revised CGAAP	CGAAP
	2011 and Prior	Historical	CGAAP	CGAAP

- For the year that the applicant implemented changes to its capitalization and depreciation policies (2012 or 2013), the applicant must file two sets of appendices, one before and one after the policy changes
- For the transition year (typically 2014), reporting in MIFRS is mandatory. Revised CGAAP schedules must be filed if the impact is material.

Review of Specific Chapter 2 Appendices

- Appendix 2-BA Fixed Assets Continuity Schedule
  - For the year of capitalization and depreciation policy changes (2012 or 2013):
    - Two appendices should be filed, one before and one after the changes
  - For the transition year (typically 2014):
    - Two appendices should be filed, one under Revised CGAAP and one under MIFRS if the change between Revised CGAAP and MIFRS is material
    - If the change from the accounting standards is not material, the applicant may choose to provide only MIFRS appendix.
    - The applicant must also indicate the fixed asset net book value balance under Revised CGAAP, the total dollar value of the change and explain why it would not be material
  - Establish the continuity of historic cost and accumulated depreciation by using the Dec. 31, 2013 regulatory gross assets and accumulated depreciation as the opening balance as at Jan. 1, 2014
  - Continuity schedules should be reconcilable to the calculated depreciation expenses (Appendix 2-C) and presented by asset account

Review of Specific Chapter 2 Appendices (contd.)

- Appendix 2-C Depreciation Expense Schedules
  - Appendix 2-CA to 2-CF – For depreciation policy changes made Jan. 1, 2012
  - Appendix 2-CG to 2-CK – For depreciation policy changes made Jan. 1, 2013
  - Each set of appendices include depreciation schedules before and after the depreciation policy changes
  - Each set of appendices requires a recalculation to determine the average remaining life of the opening balance of assets on the date of making depreciation changes
  - In general, no further changes to depreciation policy (i.e. asset service lives) are expected after the OEB mandated changes by Jan. 1, 2013.
    - Both sets of appendices assume this to be the case.
    - If the applicant has made any changes to its depreciation policy subsequent to the OEB mandated changes, applicants must:
      - identify the change, explain the nature of the change, the reason for the change, quantify the impact, and quantify the depreciation expense before and after the change.

Review of Specific Chapter 2 Appendices (contd.)

- Appendix 2-EB, 2-EC Account 1576
  - Account 1576 – To record the financial differences arising as a result of changes to depreciation and capitalization policies permitted by the OEB under CGAAP in 2012 or as mandated by the OEB in 2013
  - The drivers of the change in closing net PP&E must be identified and quantified in Appendices 2-EB or 2-EC
- Appendix 2-EA Account 1575
  - Account 1575 – Must capture all PP&E accounting changes made on transition to IFRS with the exception of those related to capitalization and depreciation that are captured in Account 1576
  - Provide a breakdown for quantification of any accounting changes arising from the transition to IFRS in relation to PP&E, including an explanation for each of the accounting changes made

Review of Specific Chapter 2 Appendices (contd.)

- Account 1576 and Account 1575 cannot be used interchangeably and the applicant must follow the required accounting treatment applicable under each account

- Applicants are typically expected to have balances in Account 1576 as a result of the OEB mandated capitalization and depreciation policy changes under CGAAP

- Applicants may also have balances recorded in Account 1575 for any further PP&E accounting changes made on transition to IFRS

- Rate of return component to be applied to the balance in Account 1575 and Account 1576 (per OEB letter dated June 25, 2013)

- Use of a separate rate rider (per OEB letter dated June 25, 2013) for the disposition of the balances over the proposed disposition period

Review of Specific Chapter 2 Appendices (contd.)

Example for illustration purposes only

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

Reporting Basis	Rebasing Year CGAAP Forecast	2012 CGAAP Actual	2013 CGAAP Actual	2014 CGAAP Actual	2015 MIFRS Forecast	2016 Rebasing Year MIFRS Forecast
			$	$	$	
PP&E Values under former CGAAP						
Opening net PP&E - Note 1			1,000,000	750,000	490,000	
Net Additions - Note 4			250,000	230,000	200000	
Net Depreciation (amounts should be negative) - Note 4			-500,000	-490,000	-450000	
Closing net PP&E (1)			750,000	490,000	240,000	
PP&E Values under revised CGAAP (Starts from 2012)						
Opening net PP&E - Note 1			1,000,000	850,000	690,000	
Net Additions - Note 4			150,000	130,000	140000	
Net Depreciation (amounts should be negative) - Note 4			-300,000	-290,000	-300000	
Closing net PP&E (2)			850,000	690,000	530,000	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			-100,000	-200,000	-290,000	

Ensure PP&E values agree to Appendix 2-BA where applicable

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	290,000
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	94,250
Amount included in Deferral and Variance Account Rate Rider Calculation	-	384,250

WACC should be updated once it is updated and agreed/approved.

WACC	6.50%
# of years of rate rider disposition period	5

Review of Specific Chapter 2 Appendices (contd.)

- Appendix 2-U Account 1508, Sub-account IFRS Transition Costs
  - An applicant should file a request for review and disposition of the balance in Account 1508 Other Regulatory Assets, sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, sub-account IFRS Transition Costs Variance
  - The balance requested should include actual audited incremental transition costs to date, the unaudited actuals for the bridge year and a forecast of any remaining costs to be incurred for the test year
  - Must explain how the costs recorded meet the criteria of one-time IFRS administrative incremental costs
  - Given that applicants are expected to adopt IFRS effective January 1, 2015, applicants are expected to close this account following the final disposition of the balance in this proceeding.

Questions?

Ratepayers' Perspective

OEB's Orientation Session for Electricity Distributors Rebasing for 2016 Rates

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
- 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
- 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

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
  - Revenues (load forecast and offsets), PILS, cost allocation and rate design, D&V accounts

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
- Building our own comprehensive database of comparative data

Consistent Issues

- RRFE
  - Outcome focus – Metrics and targets
  - Benchmarking
  - Robust capital planning requirements
  - Value for money
  - 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 Conference

- 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

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
  - Still uncertainty on application of the RRFE
- Most cost of service application can settle
- How do 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
  - Utility counsel has limited freedom to protect you
  - Good questioners are well prepared
- Approach
  - Don’t “play the game” - use your natural advantage
  - Credibility not easily lost, but also not easily regained
  - Pay close attention to questions from Board members

Thank you

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