Ontario

Ontario Energy Board

Commission de l'énergie de l'Ontario

Handbook
for
Utility Rate Applications

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1. Table of Contents

1. Introduction

The Ontario Energy Board (OEB) has developed this Handbook to provide guidance to utilities and stakeholders on applications to the OEB for approval of rates. Rates are the key revenue tool for regulated utilities. Under legislation, regulated natural gas utilities and electricity distributors, transmitters and Ontario Power Generation (OPG)[1] are only permitted to charge for their regulated services through an order issued by the OEB. In making an order, the OEB must set rates or payments that are just and reasonable.

This Handbook outlines the key principles and expectations the OEB will apply when reviewing rate applications. The Handbook is applicable to all rate regulated utilities[2], including electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation. It has been developed based on the OEB's policies and the experience gained through the processing of rate applications since the release of the *Renewed Regulatory Framework for Electricity* (RRFE)[3]. The OEB expects utilities to file rate applications consistent with this Handbook unless a utility can demonstrate a strong rationale for departing from it.

The Handbook contains the following sections:

- Background on the Renewed Regulatory Framework
- Legislative Mandate and Test
- Rate Applications and the Adjudicative Process
- The OEB's Review of the Key Components of Rate Applications
- Rate-Setting Options
- Rate-Setting Policies

[1] OPG is the only generator subject to rate regulation by the OEB.
[2] This Handbook uses the term "utilities" to refer to all rate regulated entities unless specified otherwise.
[3] *Board Report: Renewed Regulatory Framework for Electricity Distributors,* October 18, 2012 (RRFE Report)

2. Background on the Renewed Regulatory Framework

The OEB established a new framework for electricity distribution rate regulation in 2012. The *Renewed Regulatory Framework for Electricity* is a foundational policy: it articulates the OEB's goal for an outcomes-based approach to regulation which aligns the interests of customers and utilities. Key principles of the RRFE include the expectation for continuous improvement, robust integrated planning and asset management that paces and prioritizes investments, strong incentives to enhance utility performance, ongoing monitoring of performance against targets, and customer engagement to ensure utility plans are informed by customer expectations.

The OEB set out its goals for the RRFE as follows:

> The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.[4]

An important aspect of the RRFE is the evolution to an outcomes-based approach. The OEB "believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation."[5] There are four categories of outcomes under the RRFE: customer focus, operational effectiveness, financial performance and public policy responsiveness:

- Customer Focus: Customer engagement is now an explicit and important component of the regulatory framework. Utilities are expected to develop a genuine understanding of their customers' interests and preferences and reflect those interests and preferences in their business plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and by providing services in a manner which is responsive to customer preferences.

[4] RRFE Report, p. 1.
[5] RRFE Report, p. 2.

- Operational Effectiveness: Utilities are expected to demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. The OEB will assess performance trends and look for evidence of strong system planning and good corporate governance. The OEB will use benchmarking to assess a utility's performance over time and to compare its performance against other utilities. Utilities are expected to demonstrate value for money by presenting plans for delivering services that meet the needs of their customers while controlling their costs.

- Public Policy Responsiveness: Utilities are expected to consider public policy objectives in their business planning and to deliver on the obligations required of regulated utilities. These obligations may evolve over time and therefore this Handbook does not provide a comprehensive list of all requirements. Utilities are expected to demonstrate that they have considered Conservation First[6] in their investment decisions. The OEB will expect to see proposals for how distributors are supporting low income customers through programs such as LEAP and/or OESP[7], or through other distributor-specific programs. Electricity distributors and transmitters are expected to expand or reinforce their systems to accommodate the connection to their system for renewable energy generation facilities and the OEB expects their system plans to include details on how they will meet this requirement. Natural gas utilities are expected to identify investments or programs that have been planned to meet obligations under Ontario's cap and trade program.

- Financial Performance: Utilities are expected to demonstrate sustainable improvements in their efficiency and in doing so will have the opportunity to earn a fair return. The OEB will monitor the financial performance of each utility to assess continuing financial viability and to determine whether returns are excessive. Utilities have a choice of rate-setting methods to meet their particular needs. Additional tools are available to support infrastructure investment. Utilities must report comprehensive and consistent information, allowing for comparisons over time and across utilities. The OEB will act on its obligations to ensure a financially viable sector where performance indicates that a regulatory response is needed.

[6] Conservation First is a government policy referred to in the Long-Term Energy Plan.
[7] Low Income Energy Assistance Program (LEAP) and Ontario Electricity Support Program (OESP).

Although the RRFE was developed specifically for electricity distributors, the OEB has for some time indicated that the principles underpinning the RRFE are applicable to all regulated utilities (natural gas utilities, electricity distributors, electricity transmitters and Ontario Power Generation).

Since the release of the RRFE Report, over half of Ontario electricity distributors have applied for rates under the RRFE. Enbridge Gas Distribution Inc. also applied using the principles of the RRFE. Based on its review of those rate applications, the OEB has now completed an assessment of the RRFE and the principles underpinning it. This Handbook outlines how the RRFE will be applied to all regulated utilities going forward. The framework will be referred to as the *Renewed Regulatory Framework* (RRF) in this document and by the OEB going forward to reflect this transition.

3. Legislative Mandate and Test

The foundation for the OEB's public interest mandate is the *Ontario Energy Board Act, 1998*. The OEB Act sets out the objectives for the OEB's regulation of natural gas and electricity. The OEB balances these objectives in order to protect consumers, set demanding but fair performance expectations for utilities, facilitate the evolution of the sector, and support the policies of the Ontario government.

The OEB's authority to set rates for electricity distribution, transmission and payments for OPG[8] is set out in section 78 of the OEB Act. The key test is that the rates or payments must be "just and reasonable." The OEB reviews the information and proposals in a rate application in order to determine whether the proposals are reasonable for both consumers and the utility. For natural gas, the OEB's authority to set just and reasonable rates is in section 36 of the OEB Act.[9]

For all regulated utilities, the onus is on the utility to demonstrate that its rate (or payment amount) proposals are just and reasonable. If the OEB determines that the proposals are not just and reasonable, then it may set other rates (or payment amounts) which it determines are just and reasonable.

[8] For OPG, Ontario Regulation 53/05 also defines the OEB's authority.
[9] Details of the legislative provisions are set out at Appendix 1.

4. Rate Applications and the Adjudicative Process

This Handbook applies specifically to rate applications, under any of the legislative sections identified above, which are intended to set rates for a multi-year period (Custom IR), or for the first year of a multi-year period (Price Cap IR or Revenue Cap IR). Under the RRF there are a variety of incentive rate-setting (IR) options which are discussed further in section 6 (Rate-Setting Options).

A comprehensive rate application has three main components: the business plan (along with supporting documentation and reports), historical and forecast information, and rate models that show the derivation of specific proposed rates based on the data.

- Business plan: The utility's plan for its business is foundational to the proposals included in its rate application. This includes the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the application and the plan to meet them. The OEB expects the business plan to be informed by the utility's engagement with customers. The business plan is supplemented and supported by the associated plans, reports and documentation (including system plans[10], capital and operational plans, programs, benchmarking, external reviews, and customer engagement activities) which form the core of the rate application. This utility business plan may differ from the corporate business plan that may include matters that go beyond the scope of the OEB's review in a rate application.

- Historical and forecast information: Information filed in support of a rate application facilitates a thorough review of the utility's proposals and ensures continuity in the regulation of each utility over time. The filing of this information does not mean that the OEB will approve every aspect of what is filed in a rate application. The OEB assesses the utility's plans, and the resultant costs and revenue requirement, in order to consider the benefits to customers and a fair return for utilities in setting just and reasonable rates.

[10] The term "system plan" is used in this Rate Handbook to refer generically to all types of plans that apply to the various sectors; that is "distribution system plan" for electricity and natural gas distributors, "transmission system plan" for electricity transmitters, and any nuclear and hydro-electric generation asset plan that OPG may file in the future.

- Rate models: The OEB has developed a set of rate models for electricity distributors which facilitates the review of rate applications and which distributors are required to use. These models are one of the tools the OEB uses to enhance the efficiency, consistency and accuracy of the review process.

To assist utilities, the OEB has developed filing requirements that identify the information that needs to be provided in an application. There are separate filing requirements for electricity distributors, electricity transmitters, natural gas utilities, and Ontario Power Generation. The OEB expects utilities to present rate applications that are complete and of high quality. A rate application is complete if it contains all of the information (data, reports and analysis) that the OEB has identified in the filing requirements. In addition to meeting the requirements from the filing requirements, high quality rate applications also address all of the regulatory policy considerations relevant to the company in a comprehensive, consistent and clear presentation that articulates the need for the utility's proposals and the value to customers.

In the past, the OEB used the regulatory process itself to augment a deficient application to ensure the information was complete and consistent. This approach added complexity and time to the process, increasing regulatory costs. In recent years, the OEB has conducted initial reviews of applications for completeness, to ensure that only applications which are substantially complete are allowed to proceed. A rate application must demonstrate on its face that it is of sufficient quality to support the OEB's rigorous review process. An application that does not meet this standard will not be processed; it will be returned for further work. This is one of the ways the OEB will ensure that utilities take full ownership of all aspects of the information and proposals included in their applications.

The OEB uses an open and transparent adjudicative process to review rate applications. The adjudicative process can involve a number of steps, depending on the type of application, to ensure that a utility's proposals are adequately examined and "tested" during the review. (Potential tools include interrogatories, technical and settlement conferences, and an oral hearing). The review involves stakeholders, including customer representatives and other groups. OEB staff ensures that the views of customers are considered in the application process by organizing community meetings to gather consumer views on the utility's proposals, using different media to notify customers that an application has been filed and facilitating the filing of letters of comment to the OEB from customers. The OEB is further augmenting its processes through the Consumer Engagement Framework to ensure customers have a stronger voice in the adjudicative process. The OEB uses the adjudicative process to ensure its review results in just and reasonable rates for customers. The OEB's approach to reviewing utility proposals within rate applications is discussed in the remaining sections of this Handbook.

5. The OEB's Review of the Key Components of Rate Applications

One of the OEB's primary goals is to ensure that utilities are delivering cost effective, efficient, reliable and responsive services to customers. The RRF is intended to elevate utility performance by creating incentives for superior performance. The RRF focuses on increased effectiveness and continuous improvement in meeting customer needs, including cost control and system reliability and quality objectives.

A utility's proposals are expected to demonstrate the alignment of the utility's strategic objectives with its current and future customers' expectations for reliable and reasonably priced service. The utility is expected to integrate its business challenges, and what its customers are saying, to create a compelling business plan that directly links to proposals included in the rate application and the four performance outcomes of customer focus, operational effectiveness, public policy responsiveness, and financial performance. In reviewing utility proposals, the OEB will analyze past performance but is even more concerned with future performance. The Ontario energy sector has gone through significant change, and even more change is expected in the future, particularly technology-driven change which has the potential to deliver significant benefits to customers.

The OEB will use a variety of tools to aid its review work, including trend analysis, cost benefit analysis, reviews of distributor due diligence processes (planning, risk management, governance, etc.), benchmarking and other analytical tools. The OEB sets just and reasonable rates based on a total revenue requirement that is informed by an assessment of a utility's spending proposals. If the OEB determines that a specific project or program has not been adequately justified, this may result in a reduction to the requested revenue requirement. It is the utility's responsibility to operate its system, and undertake the projects and programs it needs to meet performance requirements, within the funding provided through rates. This provides the utility with the responsibility and flexibility to meet its obligations in ways which benefit customers and the utility.

In reviewing utility proposals in rate applications, the OEB's key considerations are:

- **A focus on cost effective delivery of outcomes that matter to customers**
- **Robust planning, informed by customer preferences and driven by benefits to customers, with appropriate pacing and prioritization to control costs and manage risks**
- **Performance assessments which analyze the level of continuous improvement and a utility's ability to plan and execute plans**

The following key components are addressed in this section:

- Business plan
- Customer engagement
- Planning
- Outcomes and performance metrics
- Performance scorecards
- Benchmarking
- Operations, Maintenance and Administration (OM&A) and Compensation Expenses
- Bill Impacts
- Mergers, Acquisitions, Amalgamations and Divestitures (MAADs)
- Non-Regulated Activities and Affiliate Transactions

Business Plan

A utility's business plan for its regulated activities is fundamental to the evaluation of the proposals in its rate application. The business plan (which is included in the Executive Summary of the application) should describe the overall strategy for the regulated business, particularly the utility's goals, how these goals relate to what is sought in the rate application and the plan to meet them, and how customers will benefit. It forms the "story" that underpins the rate application as a whole and its constituent parts. The business plan should address the utility's circumstances and challenges, integrate its customers' expectations, set performance commitments, and demonstrate how the results will be achieved. This business plan is supplemented and supported by the associated plans, reports and documentation (including system plans, capital and operational plans, programs, benchmarking, external reviews and customer engagement) which form the core of the rate application.

The business plan should demonstrate that the utility's goals are appropriately aligned with the needs and preferences of its customers and the objectives of the RRF, and that the utility is well positioned to deliver on its goals. This information will allow the OEB to understand the impacts of the business plan on key areas of the application such as customer service, system reliability, costs and customer bills.

In reviewing a utility's proposals in a rate application, the OEB will consider whether the business plan demonstrates how the utility's objectives are:

- **Translated into outcomes**
- **Relate to what is being sought in the application**
- **Align with the objectives of the RRF**
- **Align with customer preferences and expectations**

Customer Engagement

Customer engagement is foundational to the RRF. Enhanced engagement between utilities and their customers provides better alignment between utility plans and customers' needs and expectations. Today's customers are more informed and more active participants in their energy services. They should have a say in shaping utility plans, particularly given the customer's role in conservation efforts and the customer-focused nature of future technological innovation. Customers should also help determine the pace of utility investment.

Each type of utility will have a variety of customers to include in engagement activities. For example, natural gas utilities have end-use customers and transportation customers. Electricity distributors have end-use customers, generators, and sometimes other embedded distributors. Electricity transmitters have customers which are distributors, generators, and large end-use customers. Ontario Power Generation has an indirect relationship with end-use customers. Although the types of customers vary, the principles presented here are applicable to all utilities. The OEB expects utilities to adapt these principles to their particular circumstances.

Utilities are expected to develop a genuine understanding of their customers' interests and preferences and integrate those interests and preferences into their plans. Utilities are expected to demonstrate value for money by delivering genuine benefits to customers and providing services in a manner which is responsive to customer preferences. Customer engagement is expected to inform the development of utility plans, and utilities are expected to demonstrate in their proposals how customer expectations have been integrated into their plans, including the trade-offs between outcomes and costs. Existing processes and customer interactions should also inform the customer focus element of the utility's proposals. For example, reliability complaints could inform investment program priorities, such as targeting poor performing feeders for upgrades, or the use of smart grid technology to reduce the duration of outages.

The OEB expects a utility's rate application to provide an overview of customer needs, preferences and expectations learned through the utility's customer engagement activities. The application must also demonstrate how the utility has reflected customer input in the development of its plans. The OEB will evaluate whether the utility's application is reflective of, and appropriately informed by, customer needs, expectations and preferences and whether the utility is positioned to deliver on its plans in a way that will provide value to customers.

In reviewing customer engagement, the OEB will consider:

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

The OEB is not specifying how customer engagement should be done or how customer feedback should be received. It can take many forms, and the OEB expects utilities to consider a range of approaches, using both existing and new processes. A customer satisfaction survey is a tool to gauge how a customer views the past performance of its utility, but it is not a tool that engages customers on future plans and therefore is not sufficient to meet the OEB's expectations for appropriate engagement to inform the utility's plans. Planning is an ongoing utility activity, not just something that is done in preparation for a rate application. Likewise, customer engagement to inform utility planning must also be an ongoing activity. The OEB will consider the adequacy of customer engagement in assessing whether it has been demonstrated that a proposal provides value to customers. If the OEB determines that customer engagement has not been adequate, then the OEB may conclude that a program or project is not adequately justified, in whole or in part, and this could result in a reduction to the requested revenue requirement.

Planning

Robust planning is one of the foundations of the OEB's RRF. The utility's business plan sets the context for the proposals in a rate application (as part of the Executive Summary of the application). The utility's system plan is an important component of the application and complements and supports the specific capital and operational plans and programs, and the associated budgets, which form the utility's overall business plan.

A utility's core business in serving customers is asset management, and strong asset management is essential to delivering reliable and quality energy services that customers value. Strong planning will help drive operational effectiveness, and the utility system plan will be an important component of the utility's business plan which supports the rate application. The capital intensive nature of the energy sector and long life of most assets means that investment brings with it the likelihood of rising costs as aging and fully depreciated assets are replaced with new assets. Therefore it is particularly important that planning be optimized in terms of the trade-offs between capital and operating expenditures, and that investments be prioritized and paced in a way that results in predictable and reasonable rates. Utilities are expected to develop plans that deliver lower cost solutions over the long-term through a Conservation First approach, integration with regional plans, and consideration of the evolution of the sector, including innovation and new technologies. Utilities are expected to engage customers and incorporate their expectations into their planning.

The OEB's comprehensive policies for electricity distributor system planning, and filing requirements are set out in *Chapter 5 of the Filing Requirements for Electricity Rate Applications*. The planning principles, as set out in the next section, are applicable to all rate-regulated utilities. However, other utilities (natural gas utilities, electricity transmitters, and OPG) would include different types of initiatives in their plans. For example, a natural gas utility would need to incorporate the cap and trade program in its system plan. The discussion below is presented in the context of electricity distribution system plans, but is intended to provide guidance to electricity transmitters, natural gas utilities, and OPG.

Electricity Distribution System Plans

The OEB requires electricity distributors to file a distribution system plan (DSP) every five years, regardless of the rate-setting method chosen. The DSP consolidates documentation of a distributor's asset management process and capital expenditure plan. The asset management process is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus. The asset management process needs to be informed by an asset condition assessment such as equipment testing results, maintenance and usage history, historical failures or system weaknesses. Information is also required on the consequences of the failure of assets (such as how many customers will be affected, the type of customers and the time to restore the system) to appropriately prioritize plans. The capital expenditure plan sets out and justifies a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance and operations expenditures.

A DSP must contain sufficient information to allow the OEB to assess whether and how a distributor has planned to deliver value to customers, how the plan supports the effective management of the assets, and how a distributor is seeking to control the costs and related rate impacts of proposed investments. The asset management plan underpinning the DSP should be directly linked to the proposed budget, to demonstrate that the proposed capital expenditures have been determined through the necessary optimization and prioritization process.

The OEB has consolidated, streamlined, and strengthened its planning policies into an integrated approach. Under this integrated approach, all network investments will be planned together, including network renewal and expansion, connection of renewable generation facilities, smart grid development and implementation, conservation, and investments arising from regional planning processes.

The DSP is expected to have the following characteristics:

- Consolidated and stand-alone (i.e. not presented through separate parts across an application)
- Includes all assets, both system assets and general plant
- Underpinned by an asset condition assessment
- Linked directly to the proposed budget
- Integrates considerations of conservation, smart grid, renewable generation connection, regional planning, and any relevant public policies
- Demonstrates how the utility has planned to deliver value to current and future customers
- Demonstrates how the plan supports the effective management of the assets
- Demonstrates how the plan is optimized (by considering alternatives, including different capital program options, maintenance or operating solutions, the use of conservation to defer investments, the use of new and emerging technologies, etc.) and how projects are prioritized and paced to recognize potential rate impacts

In a cost of service proceeding the OEB will consider the entire five year DSP as a means of assessing the distributor's planning and whether the test year requests are appropriately aligned with the DSP. The OEB has established a policy for the funding of capital for electricity distributors on the Price Cap IR option.[11] Requests for funding under these mechanisms must meet all of the same requirements for capital spending

[11] *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 and *Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016

as would be in a cost of service or Custom IR application. Any Incremental Capital Module that involves a significant increase to a capital budget may need to be supported by a DSP along with customer engagement analysis.

In reviewing the utility system plan, the OEB will consider the following:

- **Have the criteria outlined in Chapter 5 of the *Filing Requirements for Electricity Rate Applications* been addressed?**
- **Does the plan provide a direct and clear alignment of the various components, explicitly showing how the process steps lead to an optimized plan and corresponding capital and operational plans and budgets?**
- **How has the plan addressed the information and preferences gathered from the utility's customer engagement work?**
- **Does the plan deliver quantifiable benefits for customers?**
- **Does the plan support the achievement of the utility's identified outcomes, and the outcomes of the RRF (customer focus, operational effectiveness, public policy responsiveness, and financial performance)?**
- **Has the company controlled costs through optimization, prioritization and pacing?**
- **Has the plan appropriately integrated conservation, renewable generation connection, regional plans, smart grid, and any relevant public policies?**

Outcomes and Performance Metrics

The RRF is an outcomes-based approach. A utility is accountable for identifying specific outcomes valued by its customers and explaining how the utility's plans and proposed expenditures deliver those outcomes. These outcomes are linked to performance metrics, which will be used to show whether the outcomes have been achieved. Utilities are expected to consider cost trends, benchmarking of comparable utilities, and learnings from their customer engagement in setting outcomes and performance metrics.

Outcomes are not activities such as the rebuilding of a pole line, but rather the qualitative expression of the utility's goals and objectives. The outcomes should be based on the utility's business plan and should identify outcomes at the key program level that flow directly from the cost proposals. The outcomes should demonstrate the value proposition for customers and/or public policy goals. Effective outcomes, in combination with the materiality thresholds, will allow the OEB to focus its assessment on results that drive value for customers and not a line by line review of expenditures. The OEB has set four categories of outcomes through the RRF: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

Utility outcomes should link directly to one or more of these categories and be chosen to illustrate the benefits expected from key programs the utility is proposing.

Performance metrics are generally quantitative measures which will be used to assess whether the outcomes have been achieved; however qualitative measures may also be considered. Performance metrics ensure that the outcomes are measurable. For the pole line example noted above, the outcome could be increased reliability for that particular feeder.

The OEB has established a set of performance metrics for electricity distributors through its Performance Scorecard. In a rate application, the electricity distributor must identify metrics for its identified outcomes, which will often be in addition to those scorecard measures.

Other utilities (natural gas utilities, electricity transmitters and OPG) should establish performance metrics which are directly linked to the identified outcomes related to their business plans. These performance metrics will generally be part of the set of performance measures the utility has proposed for a performance scorecard (discussed further in the next section).

In reviewing a utility's proposed outcomes and performance metrics, the OEB's key considerations are:

- **A focus on strategy and results, not activities**
- **The need to demonstrate continuous improvement**
- **Outcomes which are demonstrated to be of value to customers**
- **Performance metrics which will accurately measure whether outcomes are being achieved, and which include stretch goals to demonstrate enhanced effectiveness and continuous improvement**

Performance Scorecards

Customers expect continuous improvement in the utility services delivered to them. Utilities must demonstrate their performance through effective and transparent reporting. As part of the RRF, the OEB has developed performance measures and standards for electricity distributors in four areas: customer focus, operational effectiveness, public policy responsiveness, and financial performance.[12] This Performance Scorecard brings greater transparency to utility performance and

[12] *Report of the Board - Performance Measurement for Electricity Distributors: A Scorecard Approach*, March 5, 2014

enhances the ability to assess performance over time and to compare performance across utilities.

In its rate application, an electricity distributor should discuss its performance for each of the Performance Scorecard measures over the last five years, and explain the drivers for its performance. The OEB's review of a utility's proposals will consider the utility's past and target performance against the four RRF outcomes. The electricity distributor is also expected to discuss its plans for continuous improvement. It is expected to identify performance improvement targets that will lead to improvement in its scorecard performance over the term of the rate-setting plan.

All other utilities (natural gas utilities, electricity transmitters, and OPG) are expected to propose a scorecard (including the performance metrics linked to the proposed outcomes) to measure and monitor performance and, where appropriate, enable comparisons between utilities. The format should be similar to the scorecard developed for electricity distributors (available on the OEB's website) and include measures for customer focus, operational effectiveness, public policy responsiveness, and financial performance. After the OEB has set approved scorecards for one or more electricity transmitters and natural gas utilities, those scorecards will provide additional guidance to other utilities filing applications. However, a utility is also encouraged to propose other performance categories and measures that it believes would be meaningful for its operations as an Ontario utility.

The proposed scorecard should include data for at least five years. A utility may propose measures for which five years of data is not yet available if it commits to collecting and reporting the data through the course of the plan. Furthermore, the lack of historical data should not be a barrier to the setting of new measures, especially if these are important to monitoring a utility's future performance e.g. a measure on system utilization could report on how a utility is managing its assets. The OEB may undertake further work to make enhancements to any scorecard proposed through an application as the OEB continues to develop its approach to performance assessment, and to maintain a level of consistency for scorecards between utilities.

In reviewing the proposed performance scorecard, the OEB's key considerations are:

- ***Whether the measures capture key factors of utility performance***
- ***Whether the scorecard enables assessments over time and appropriate comparisons with other utilities***
- ***Whether the utility has set reasonable targets for its performance metrics***

Benchmarking

Benchmarking will be used by the OEB to review a utility's proposals, including at the program level[13]. Utilities are expected to provide benchmarking analysis which supports their proposed plans and programs and demonstrates continuous improvement.

The OEB currently conducts total cost benchmarking for electricity distributors. An econometric model is used to generate efficiency rankings and assign electricity distributors to one of five groups based on their total cost performance, including both capital and OM&A costs. These results are used to set the productivity stretch factors for the incentive rate-setting mechanism (IRM) applications, and will also be a consideration in assessing a utility's cost trend performance. An electricity distributor is expected to provide a forecast of its efficiency assessment using the model for the test year. This provides the OEB with a directional indicator of efficiency.

Utilities are generally not required to present total cost benchmarking analysis as part of their applications, unless they have been ordered to do so through an OEB decision. Two other types of benchmarking are required in rate applications:

- External benchmarking to analyze specific measures or specific programs by comparing year over year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group
- Internal benchmarking to assess continuous improvement by the utility over time

Benchmarking need not be limited to unit cost benchmarking (e.g. the capital cost of a billing system per customer or the cost of cable or pipe per km). Performance benchmarking in areas such as reliability or other outcomes may also be appropriate. What is important is that the utility explains how it has interpreted the benchmarking and what actions it has taken as a result of it.

With the Custom IR rate setting options, a utility can customize the rate setting mechanism for their specific circumstances. Given this flexibility, the OEB will place greater reliance on benchmarking evidence for a Custom IR application to assess proposals over the five year term. When determining what areas to benchmark, a utility should consider the following potential criteria:

[13] Such as cost per pole replacement or billing costs per customer

- Key areas where the utility's performance is considered particularly strong or particularly weak
- Areas where expenditures are a key driver for the revenue requirement
- Areas that have been targeted for specific programs
- Areas where the OEB has expressed concern in past decisions
- Areas related to performance metrics and/or performance scorecard measures
- Linkages to customer engagement analysis

Utilities are expected to present objective, well researched benchmarking information, supported by a high quality and thorough analysis (using either third party or internal resources) that can be rigorously tested.

In reviewing benchmarking, the OEB will consider:
- **The structure of the benchmarking and the comparators used**
- **The quality of the benchmarking**
- **The linkages between the results of the benchmarking and the proposals in the rate application**

OM&A and Compensation Expenses
Under the RRF, the OEB has adopted an outcomes-based approach to regulation. As a result, the review of OM&A expenses will focus on the examination of outputs and programs, and whether there is evidence of continuous improvement, rather than the discrete line items or inputs to the OM&A budgets.

In addition, because employee compensation costs are already reflected in the proposed capital and operational programs, a detailed presentation of compensation is not necessary for the OEB's consideration of the proposed program costs to achieve the expected outcomes. The OEB does expect a utility to provide a description of its compensation strategies and policies (e.g. how salary scales are set and reviewed, how target salaries are compared to external benchmarks, performance pay structures, and the board of directors oversight process) and to clearly explain the reasons for all material changes to head count and compensation, and the outcomes expected from these changes. A utility should demonstrate clearly the linkages between its compensation strategies and policies and utility performance. Additional requirements for particular utilities may also arise from specific OEB directions in prior proceedings.

In reviewing a utility's proposed expenses for OM&A and Compensation, the OEB's key considerations are:

- **Have the costs been paced at the rate of inflation, and if not, what is the rationale for increased costs**
- **If the rationale for increased costs is customer or load growth, what is the relationship between increased costs and that growth**
- **A focus on strategy and results, not activities**
- **The need to demonstrate sustainable continuous improvement**
- **The outcomes that are expected from the proposed expenses**

Bill Impacts

The OEB is sensitive to customer concerns about energy bills. Customers are entitled to reliable service at reasonable rates. The OEB has adopted a number of policies to drive further efficiencies and to ensure utilities are focussed on providing value to customers. Customer needs and expectations, the pacing and prioritization of investment, and utility performance over time and in comparison to peers are all factors that the OEB considers, and are intended to drive effectiveness and continuous improvement. Utility proposals and plans ultimately translate into customer rates and bills. Rate changes and bill impacts are a particular focus of customers, and of the OEB. The OEB will hold utilities accountable to justify the bill impacts of their proposals; effective cost control will be expected.

Importantly, each utility can choose the rate-setting approach that best suits its particular needs. A utility is expected to tailor its proposals to meet the requirements of increased investment along with the requirements for enhanced productivity, cost control, and continuous improvement to create an appropriate rate profile.

In reviewing proposals in rate applications, the OEB will assess:

- **How the utility has considered total bill impacts in its planning**
- **How the utility has demonstrated the responsiveness of its expenditure plans to the need for stable and reasonable rates for customers**
- **Whether the pacing and prioritization of planned work is appropriate in light of the bill impacts of carrying out necessary investments**
- **What the bill impacts are for only those components of the bill that are within the control of the utility (no pass-through items)**
- **Whether any mitigation is warranted**

Mergers, Acquisition, Amalgamations and Divestitures (MAADs)

The OEB has issued a *Handbook to Electricity Distributor and Transmitter Consolidations*[14] that makes clear that rate setting is generally not a consideration in reviewing a consolidation through a merger, acquisition, amalgamation or divestiture. In the first cost of service or Custom IR application following the consolidation the OEB will scrutinize specific rate-setting aspects of the MAADs transaction, including a rate harmonization plan and/or customer rate classifications post consolidation.

This will include consideration of:

- **The treatment of any premium above book value paid as part of a consolidation (no premium is to be recovered from customers).**
- **The savings that have been generated through the consolidation.**
- **Whether there were any inducements or incentives beyond the purchase price to encourage a shareholder to agree to the consolidation and if so whether there is any intent to recover the costs of those inducements or incentives from customers. Any costs incurred will be reviewed to ensure that the costs incurred are delivering the best value to customers.**
- **Whether the rate harmonization plan includes a detailed explanation and justification for the implementation plan, and an impact analysis. For acquisitions, distributors can propose plans that place acquired customers into an existing rate class or into a new rate class. Regardless of the option adopted, the OEB will assess whether the proposed harmonized rates will reflect the cost to serve the acquired customers, including the anticipated productivity gains resulting from consolidation.**

Non-Regulated Activities and Affiliate Transactions

As noted previously, the business plan filed with the rate application is not necessarily the corporate business plan for the utility. There may be aspects of the corporate business plan that are not relevant to the OEB's review of a rate application. The OEB will consider non-regulated activities and transactions with affiliates in the context of their effect on the regulated rates to customers to ensure there are no cross subsidies that negatively affect these regulated customers.

[14] January 19, 2016

Depending on the corporate structure of the utility, this could include an assessment of:

- **The reasonableness of the costs allocated to non-regulated activities within the regulated utility**
- **The costs to be charged to the regulated utility from an affiliate**
- **The revenues forecast to be received from an affiliate for services provided by the regulated utility**
- **Whether these activities affect the quality of services to be delivered to the customers of the regulated utility**
- **Whether non-regulated activities will affect the financial viability of the regulated utility, or introduce a significant enough risk that it affects debt financing costs**

6. Rate-Setting Options

The OEB's approach to rate regulation has evolved over time to create better incentives to drive utilities to improve their efficiency in a way that benefits both customers and shareholders. Performance-based regulation under the RRF is the framework for rate-setting. This is consistent with broader trends amongst regulators around the world to shift rate regulation from a process of simply recovering costs to one of driving improved utility performance through incentives.

The OEB has developed a set of rate-setting options[15] to ensure that utilities have sufficient flexibility to adopt a method that best meets their needs. Each of the methods also includes incentives and benefits for customers related to continuous improvement and productivity.

Electricity Distributors

To support the move to an outcomes based approach, the OEB recognized the need to provide flexibility in rate setting options to give utilities the necessary tools to develop business plans that meet their needs. The RRFE established three incentive rate-setting (IR) methodologies for electricity distributors: Price Cap IR (previously known as 4th Generation IR), Custom IR, and the Annual IR Index.

- Price Cap IR: Under this methodology, base rates are set through a cost of service process for the first year and the rates for the following four years are adjusted using a formula specific to each year. For electricity distributors, the formula includes an industry-specific inflation factor and two factors for productivity. One productivity factor is a fixed amount for industry-wide productivity and the other is a stretch factor, which is set each year based on the level of productivity the electricity distributor has achieved.

[15] There are rate setting options under the RRF that take into consideration actual or forecast costs, including both cost of service and custom incentive rate-setting; also called rebasing applications. Other rate-setting options, such as revenue cap and price cap incentive rate-setting, decouple the rates from costs.

- Custom IR: Under this methodology, rates are set for five years considering a five-year forecast of the utility's costs and sales volumes. This method is intended to be customized to fit the specific utility's circumstances, but expected productivity gains will be explicitly included in the rate adjustment mechanism. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations. Additional guidance on Custom IR applications is set out below.

- Annual IR Index: Under this methodology, rates are subject to the same annual adjustment formula as those under Price Cap IR. Utilities under the Annual IR Index are not required to periodically set base rates using a cost of service process, but they are required to apply the highest stretch factor. This approach is the most mechanistic of all rate applications. These utilities are required to provide five-year distribution system plans as a reporting requirement every five years, and like all other distributors will continue to report their performance using the OEB's Performance Scorecard. This will allow the OEB to determine whether the planning process and level of investment is adequate and whether service levels remain appropriate.

Electricity distributors may choose from any of these three methodologies. There are no eligibility requirements for any of these methods, but the rate application must meet the requirements of the rate-setting option. Those requirements are set out in the OEB's RRFE Report, in the filing requirements and in this Handbook.

Electricity Transmitters

Electricity transmitters may choose either Custom IR or a Revenue Cap IR. The Revenue Cap IR methodology is similar to the Price Cap IR option discussed previously for distributors. Individual rates are not set for each transmitter. The revenue requirement for each transmitter is approved by the OEB and this is used to set uniform transmission rates that apply throughout the province. Therefore, instead of a Price Cap IR option, a transmitter can propose an incentive mechanism for adjusting its revenue requirement in a similar manner.[16]

[16] As set out in Chapter 2 of the *Filing Requirements for Electricity Transmitter Applications*, electricity transmitters will be permitted a final cost of service proceeding as a transition mechanism, and that proceeding will incorporate certain elements and principles of the RRF (including customer engagement, benchmarking, and a transmission system plan).

Natural Gas Utilities

Natural gas utilities may choose either Custom IR or Price Cap IR. Under either approach, the term must be a minimum of 5 years. For Price Cap IR it would include a cost of service year and at least four years using an incentive adjustment mechanism.

Ontario Power Generation

The OEB established expectations that payments for OPG will be based on Price Cap IR for the hydroelectric business and Custom IR, based on the RRFE principles, for the nuclear business. The OEB may set out its expectations for future applications in its next decision and order for OPG.

Specific Considerations for Custom Incentive Rate setting

The OEB has now received and decided a number of Custom IR applications and is in a position to provide further guidance on the minimum standards for Custom IR applications to ensure that the performance-focused and outcomes-based approach is achieved as intended. A Custom IR application is by its very nature custom, and therefore no specific filing requirements have been established. However, any utility filing a Custom IR application should be informed by the cost of service filing requirements and this Handbook. The sections that follow set out the OEB's minimum standards for certain key elements of Custom IR applications.

There is no threshold test or eligibility requirement for a Custom IR application. The test for the adequacy of the application is the extent to which its features contribute to the achievement of the OEB's RRF goals and whether it meets the following standards:

- Term: A Custom IR must have a minimum term of five years. The OEB has determined that this term supports a longer term approach to planning to smooth expenditures and pace rate increases, strengthens efficiency incentives and supports innovation. Longer terms can be proposed with appropriate mechanisms for consumer protection as discussed below.

- Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

- Benchmarking: Benchmarking is a fundamental requirement of a Custom IR application, both internal benchmarking to demonstrate continuous improvement and external benchmarking as identified in Section 5. A Custom IR application without benchmarking will be considered incomplete.

- Performance Metrics: The OEB has established a scorecard for electricity distributors, however, additional performance metrics should also be proposed so that expected outcomes can be monitored. All other utilities must propose a comprehensive scorecard that is informed by the scorecard for electricity distributors, but specifically includes other performance metrics aligned to the outcomes identified in the application. This is required for both Custom IR and cost of service rate applications.

- Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to that method for the duration of the approved term and will not seek early termination or in-term updates except under exceptional circumstances and with compelling rationale.

A Custom IR application can include a five year forecast of all costs with proposed rates for each year that consider both these costs and the proposed productivity improvements reflected in the custom index. A utility that cannot forecast its needs within the five year term, or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances.

The ICM and ACM mechanisms for funding capital for electricity distributors, or any similar mechanism approved for transmitters, natural gas distributors or OPG, are not available for utilities setting rates under Custom IR.

An acceptable adjustment during a Custom IR term is a Z factor mechanism for cost recovery of unforeseen events. The OEB has a policy for Z factors for electricity distributors and transmitters that applies for any rate-setting option chosen by a utility. The OEB has established a materiality threshold for electricity distributors for eligibility to claim for a Z factor event. Electricity transmitters are expected to propose a materiality threshold in their applications. The OEB has approved Z factor mechanisms for natural gas distributors in previous proceedings, and they may propose mechanisms in their future rate applications.

Given the custom nature of a Custom IR application, utilities may propose alternative mechanisms for unforeseen events to coordinate better with other aspects of their custom proposals. In doing so they should consider the OEB's expectations for protecting customers from excess earnings, as discussed in the next section.

- Protecting Customers: A key objective of incentive regulation is to drive productivity improvements within the utilities. The OEB has determined that with the Custom IR rate setting option, customers will benefit from the expected productivity improvements during the term through the custom index.

  Utilities that achieve productivity improvements above what is expected are allowed to keep certain earnings above the approved ROE. However, the OEB expects utilities filing a Custom IR application to propose one or more mechanisms to protect customers from utility earnings that become excessive. Proposals would typically include mechanisms such as off ramps (discussed below) and earnings sharing but could include other approaches specific to a utility's circumstances.

For electricity distributors, the OEB has established an off-ramp that involves a threshold above the distributor's approved return on equity at which a regulatory review may be triggered.[17] An electricity distributor can propose an alternative threshold that provides greater protection for customers. Other utilities may propose an off-ramp that takes into consideration the OEB's objective of protecting customers from excess earnings.

The OEB does not require a Custom IR to include an earnings sharing mechanism, except in the context of deferred rebasing periods as part of electricity distributor consolidation[18]. While an earnings sharing mechanism protects customers from excess earnings, it can diminish the incentives for a utility to improve their productivity, and any benefits to customers are deferred. The requirement for a custom index ensures that benefits are shared immediately with customers through productivity commitments.

If a utility proposes an earnings sharing mechanism as its mechanism to protect customers against excess earnings, it should be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term, consistent with the approach to limiting mid-term updates.

If a Custom IR application does not meet all of these requirements, the OEB may impose a reduced term, reject the application or determine that an application is incomplete and will not be processed until the requirements are met.

[17] This policy was reaffirmed in the RRFE Report.
[18] *Report of the Board: Rate-Making Associated with Distributor Consolidation*, March 26, 2015

7. Rate-setting Policies

The OEB has a number of accounting and rate-setting policies that are applicable to rate applications. Appendix 3 includes summaries of these policies. The OEB expects to update this appendix as more policies are developed. Utilities and stakeholders should consult the relevant policy documents (which are available on the OEB website) for detailed information.

Appendix 1: Excerpts from the *Ontario Energy Board Act, 1998*

This appendix sets out the key legislative provisions related to rate setting for natural gas and electricity.

Statutory Objectives

Board objectives, electricity

1. (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

1.1 To promote the education of consumers.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

Board objectives, gas

2. The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.
2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
3. To facilitate rational expansion of transmission and distribution systems.
4. To facilitate rational development and safe operation of gas storage.

5. To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers.

Natural Gas Rate Setting

Order of Board required

36. (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.

Order re: rates

(2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.

Power of Board

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

Burden of proof

(6) Subject to subsection (7), in an application with respect to rates for the sale, transmission, distribution or storage of gas, the burden of proof is on the applicant.

Electricity Distribution and Transmission Rate Setting

Orders by Board, electricity rates

Order re: transmission of electricity

78. (1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract.

Order re: distribution of electricity

(2) No distributor shall charge for the distribution of electricity or for meeting its obligations under section 29 of the *Electricity Act, 1998* except in accordance with an order of the Board, which is not bound by the terms of any contract.

Rates

(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity or such other activity as may be prescribed and for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*.

Burden of proof

(8) Subject to subsection (9), in an application made under this section, the burden of proof is on the applicant.

Ontario Power Generation Payment Setting

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. .

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section.

Appendix 2: Glossary of Terms

Advanced Capital Module

The Advanced Capital Module (ACM) is an evolution of the Incremental Capital Module (see below). The ACM improves the regulatory efficiency for the review and approval of proposed incremental capital expenditures. An ACM proposal is made during a cost of service application to identify, based on the 5-year capital plan in the Distribution System Plan, qualifying incremental capital expenditures during the subsequent IRM period that are necessary but require funding beyond what is sustained by IRM-adjusted rates and customer and load growth. Reviewing ACM projects as part of a cost of service application allows for testing of the need, pacing and prioritization of projects as part of the more comprehensive review that occurs in processing a cost of service application. However, rate riders to fund ACM projects only come into service when the assets enter service during the IRM period.

Annual Index Rate-setting

The Annual Index Rate-setting method is a variation on the Price Cap IR method that is suitable to utilities with very stable investment expectations; these will typically be experiencing little growth and where investments are largely stable and to replace existing assets at end-of-life. A utility under the AIR has rates adjusted by the Price Cap IR method, but where the stretch factor is set at the highest amount. However, a utility under the AIR does not have to periodically rebase rates through a comprehensive cost of service review unless and until its circumstances change.

Capital Expenditures

Capital expenditures are amounts spent by a utility to acquire or enhance fixed assets, such as land, buildings, and major equipment. When the asset is ready to be used, the expenditure is added to rate base as a capital addition. The expenditure is then recovered through rates over the life of the asset.

Capitalization Policy

Capitalization policy is the accounting policy used to determine whether money spent in a given year should be treated as a capital expenditure or as an operating, maintenance and administrative expense. If the amount is determined to be part of capital expenditures, then the amount is added to rate base (capitalized) and recovered gradually over time.

Conditions of Service

Electricity and natural gas distributors are required by the OEB to describe their customer-facing operating practices in a Conditions of Service document. This document includes topics such as connection policies, security deposits, and opening or closing accounts. Each distributor must ensure that its Conditions of Service is public and readily available to customers.

Conservation and Demand Management

Activities and programs which are designed to reduce electricity use are known as Conservation and Demand Management, or CDM.

Cost Allocation

Cost allocation is the process of dividing a utility's total costs amongst different customer classes as fairly as possible. The objective is to allocate costs in a way that reflects how each customer class uses the utility's services. Once the costs are allocated to each customer class, the rates are set to recover those costs.

Cost of Capital

The cost of capital is the cost associated with the debt and equity which are used to finance a utility's business. The OEB sets the level of debt and equity in the capital structure. The OEB also sets the cost of debt (long-term and short-term) and the return on equity, based on market conditions and the risks utilities face. The cost of capital is included in rates, but a utility could earn a higher or lower return on equity, depending upon its performance.

Cost of Service

Cost of service is the total cost for a utility to provide service to its customers. A cost of service application is a detailed presentation of a utility's costs. The OEB reviews a cost of service application and decides the rates that a utility will charge its customers. The OEB examines the utility's operating, maintenance and administrative expenses and capital expenditures, as well as the expected number of customers and total amount of energy delivered. The cost of service does not include the commodity costs of the energy (natural gas or electricity); those costs are treated separately.

Customer Class

A customer class is a group of customers who use a similar amount of energy, or use energy in a similar way (for example, residential customers). A utility's total costs are divided among the customer classes to set rates. The cost to serve each customer in a particular class is similar, and therefore it is fair for all customers in a class to pay the same rate.

Custom Incentive Rate-setting (Custom IR)

While the Price Cap IR option, along with options such as ICMs and ACMs should be adequate for most utilities, some utilities may find that their circumstances, such as high growth or significant capital investments, may not be accommodated adequately through the standard approach. Utilities with significant operating and capital expenditure needs may apply for a multi-year (minimum five years) Custom IR plan where rates are set for all years of the plan term.

Deferral and Variance Accounts

Variance accounts track the difference between the forecast cost of a project or program, which has been included in rates, and the actual cost. If the actual cost is lower, then the extra money is refunded to customers. If the actual amount is higher, then the utility can request permission to recover the extra amount through future rates. A deferral account tracks the cost of a project or program which the utility could not forecast when the rates were set. When the costs are known, the utility can then request permission to recover the costs in future rates.

Demand Meter

A demand meter measures the maximum amount of electricity used in a set period of time, for example 15 minutes. The largest commercial and industrial customers have demand meters.

Demand Side Management

Activities and programs which are designed to reduce natural gas use are known as Demand Side Management or DSM.

Depreciation and Amortization

Depreciation and amortization are standard accounting practices. Depreciation is applied to tangible assets, like buildings, poles and computers, as a way to recover the cost of the asset gradually. Over the lifetime of a tangible asset, a portion of the total cost is treated as depreciation expense each year and recovered through rates. Amortization is like depreciation, but it is used to recover the costs of intangible assets like licences and goodwill.

Distribution - Electricity

Distribution is the final stage in the delivery of electricity from generators to customers. Distributors take electricity from the high voltage transmission system and convert it to lower voltages (below 50kV). Distributors then use equipment such as lines, poles, and meters to deliver the electricity to customers. The OEB licenses and sets the rates of electricity distributors.

Distribution – Natural Gas

Distribution is the final stage in the delivery of natural gas from producers to customers. Distributors take natural gas from the high pressure transportation system and reduce the pressure. Distributors then use equipment such as pipelines, compressors and meters to deliver natural gas to customers. The OEB sets the rates of natural gas distributors.

Distribution Rates

Distribution rates are the charges that recover a distributor's own costs of providing distribution service, including operations, maintenance and administrative expense, depreciation, taxes, interest, and return on equity. A distribution rate typically includes a monthly fixed charge and a volumetric rate (a cost per unit of electricity used). The OEB approves the rates that a distributor can charge.

Feed-in Tariff (FIT)

Feed-in Tariff (FIT) is an Ontario government program offered to encourage development of renewable energy generation. Wind, water, biomass, biogas, landfill gas and solar generators are eligible for the FIT program. FIT participants enter into a long-term contract to sell electricity to the province at a guaranteed fixed price. The price is designed to cover project costs including a return on the investment.

Generation

Generation is the production of electricity from a fuel source. In Ontario, most electricity is generated at nuclear, hydroelectric, natural gas, wind, solar, and biomass facilities. Generation facilities are connected to the Ontario grid which delivers electricity to customers. Some generators are connected to the high voltage transmission system; others, typically smaller ones, are connected to the lower-voltage distribution system.

Incentive Regulation

The OEB sets rates using incentive regulation. Incentive regulation is a set of tools or methods which encourage utilities to become more efficient in ways that will benefit customers through better service and lower rate increases. The shareholders of the utilities also have the opportunity to benefit from efficiency improvements through higher earnings.

Incremental Capital Module

The Incremental Capital Module (ICM) is a capital tracker mechanism which allows for funding of significant capital investments for discreet projects during the period of incentive regulation between cost of service applications to rebase rates. Any qualifying ICM capital project must satisfy a materiality threshold to determine that the incremental capital amounts are beyond the normal level of capital expenditures expected to be funded by rates, including the effect of customer and load growth. An ICM request is requested and approved as part of a Price Cap IR application.

Interval Meter

An interval meter measures electricity use and transmits the data at regular intervals, for example each hour. Mid-size commercial and industrial customers have interval meters.

Licensed service territory

An electricity distributor's licensed service territory is the area in which the distributor has exclusive authority to distribute electricity. Every electricity distributor in Ontario must be licensed by OEB, and the licence identifies the service territory. For example, Toronto Hydro-Electric System Limited is licensed to distribute electricity within the City of Toronto.

Loss Factor - Electricity

A small amount of electricity is used up through the process of moving electricity from generators to customers. A loss factor is an adjustment to rates to recover the cost of this electricity which is consumed during delivery. The loss factor is approved by the OEB.

Meter

A meter measures natural gas or electricity use, and the data is used to bill customers. A standard meter measures the amount of electricity or natural gas consumed on a cumulative basis. These meters are read periodically, for example bi-monthly.

MicroFIT

MicroFIT projects are very small renewable electricity generation projects, with capacity under 10 kilowatts. An example of a microFIT project is a rooftop solar installation on an individual house. The owner of the microFIT project is paid a fixed price for each unit of electricity generated during the contract period (typically 20 years). MicroFIT is part of the Feed-in Tariff (FIT) program which includes larger renewable electricity generation projects (see definition of Feed-in Tariff).

Monthly Service Charge

The monthly service charge is a fixed amount each month, regardless of usage. This charge is designed to recover the fixed costs of providing distribution services which do not vary with usage. Meters, poles, and wires are some examples of fixed costs. The monthly service charge is one part of a customer's total bill; other parts of the bill may vary with usage.

Operating, Maintenance and Administrative Expenses

Operating, maintenance and administrative expenses are the costs associated with running a utility on a day to day basis. Examples of these costs include employee salaries, tools and equipment, and office expenses. Operating, maintenance and administrative expenses do not include costs associated with investment in assets, such as depreciation or interest payments.

Payments in Lieu of Taxes (PILs)

Most Ontario electricity transmitters and distributors do not pay Canadian corporate income tax. Instead, they make payments in lieu of taxes (PILs) to the Ontario government. PILs are calculated in the same way as corporate income taxes and are recovered through rates.

Price Cap

Price cap refers to the mathematical formula used to set how much a utility's rates can increase in a year when the utility is not having a full review of its rates. The formula ensures that a utility's rates will increase at a rate which is less than inflation. For most electricity distributors, rates are set for one year using a full review, and are then set for four years using a price cap formula.

Price Cap Incentive Rate-Setting

The Price Cap Incentive Rate-setting (Price Cap IR) is the standard formulaic method by which distribution rates are annually adjusted during the incentive rate-setting period between cost of service applications. The formula adjusts current rates for the following year by inflation in input prices (costs of production or service) less expected productivity improvements including a stretch factor (or consumer productivity dividend). The Price Cap IR is the standard rate-setting method for most electricity distributors between cost of service applications.

Rate Adder

A rate adder is an amount added to the base rate to provide advance funding for a special project which has been mandated by the OEB. When the project is completed and the final cost is approved by the OEB, the money collected through the adder will be deducted from the total cost. This adjusted total cost will then be recovered or refunded over time through rates.

Rate Base

Rate base is the total dollar value of all the assets used by a utility to provide energy service: wires, poles, meters, IT equipment, etc.

Rate Rider

A rate rider is an amount which is added to or subtracted from the distribution rate to recover or refund a specific amount of money for a temporary period, generally a year or less. Once the period ends, the rate rider stops.

Revenue Requirement

The revenue requirement is the total cost for a utility to provide energy service. It includes the cost of salaries, equipment, capital projects, depreciation, taxes, interest and a return on the equity invested by shareholders. The revenue requirement is used to set rates for customers.

Revenue Sufficiency/Deficiency

The revenue sufficiency or deficiency is the total amount by which a utility's revenue needs to decrease or increase from the current level to earn the revenue requirement. When the OEB sets new rates for a company, it compares the total revenue the company would earn using the current rates to the total revenue the company is entitled to earn. If there is a revenue sufficiency, it means the company would recover too much revenue under the current rates, and therefore rates need to be reduced. If there is a revenue deficiency, it means the company would not recover enough revenue under the current rates, and therefore rates need to be increased.

Revenue-to-Cost Ratio

The revenue-to-cost ratio is the relationship between the revenues from a particular customer class and the costs to serve that customer class. The ratio can be expressed as a decimal value, such as 0.90, or given as an equivalent percent value, such as 90%. For this example, a 90% revenue-to-cost ratio would mean that the customer class is paying 90% of the costs that the distributor incurs to serve that class. The revenue-to-cost ratio is one of the factors the OEB considers when setting rates. The goal is to have each class pay for the costs of serving it.

Service Reliability

Service reliability refers to the level of continuous service a utility provides without interruption or an outage. The OEB sets measures and standards which track the type and duration of outages for each utility.

Service Quality Indicators

Service quality indicators measure the level of customer service a utility provides. Examples of service quality indicators include meeting scheduled appointments, billing accuracy, and telephone response time. The OEB sets standards for key service quality indicators and monitors performance. Service quality indicators are not related to the number or duration of power outages (see definition for service reliability).

Smart Grid

The smart grid uses advanced information technology to improve communication to and from individual parts of the electricity system. The smart grid constantly monitors the system, making it more efficient. It can also detect and fix problems more quickly, thereby increasing reliability.

Smart Meter

A smart meter measures electricity consumption continuously, and transmits the data electronically. This data is used to charge for electricity according to the time of day (time-of-use rates). Residential and small commercial customers in Ontario have smart meters.

Specific Service Charges

Specific service charges are for certain extra services such as special meter reads, late payment interest, and legal letters. Each specific service charge is based on the cost to provide the service and is only charged if a customer uses the service. The costs to provide these services are not included in distribution rates, but they still must be approved by the OEB.

Tariff of Rates and Charges

The Tariff of Rates and Charges is a public document that lists the OEB-approved rates and charges for utility service. Utilities must use these rates and charges to bill their customers. Rates are listed for each customer class, along with other charges for a variety of specific services.

Transformer

A transformer is the equipment used to change the voltage of electricity. Most customers use electricity at low voltage, but electricity is transmitted over long distances at high voltage because it is more efficient. A transformer is used to reduce voltage before it is delivered to customers. A transformer can also be used to increase voltage, for example where an electricity generator is connected to the transmission system.

Transmission - Electricity

Transmission is an intermediate step in the delivery of electricity from generators to customers. Transmitters take electricity from generators and transmit it via high voltage transmission lines to distributors, where it is converted to lower voltages and provided to customers. The OEB licenses and sets the rates of electricity transmitters.

Transportation – Natural Gas

Transportation is the intermediate stage in the delivery of natural gas from producers to customers. Transporters take natural gas from the producers and transport it in high pressure pipelines to natural gas distributors who then deliver it to customers at lower pressures. The OEB sets the natural gas transportation rates for companies that operate only in Ontario.

Unmetered scattered load

Unmetered scattered load is a class of customers that use small amounts of electricity but have no meter. Examples include traffic lights, bill boards, bus shelters, and railway crossings. Rates for these customers are set on the basis of estimated consumption.

Volumetric Rate

A volumetric rate is a rate applied to each unit of electricity or gas that a customer uses. As a result, the more energy a customer uses, the higher the total charge. Some parts of the customer's bill are based on volumetric rates, for example the Electricity line. Other parts of the bill are fixed no matter how much energy is used.

Weather Normalization

Weather normalization is a mathematical adjustment to past energy usage data. This adjustment removes the impact of annual variations in weather to show what the usage would have been under normal (or long term trend) weather conditions. Utilities weather normalize data to better understand how other variables, such as energy efficiency, price, building structures and new technology impact demand. This helps utilities understand trends in energy consumption and develop more reliable forecasts.

Working Capital Allowance

The working capital allowance is the cash a utility needs in order to pay its operating, maintenance and administrative expenses during the time between when the utility spends money to provide service and when it receives payment from its customers. The working capital allowance is included in a utility's rate base.

Appendix 3: Rate-setting Policies

Accounting Standards

Utilities will use International Financial Reporting Standard (IFRS) as the basis for their regulatory accounting unless the OEB has approved another standard or the utility is eligible for Accounting Standards for Private Enterprises (ASPE)[19]. If an accounting standard other than IFRS is used and if the accounting standard relies on the approval of a regulator for the determination of certain costs (for example, capitalization of costs), then this must be disclosed to the OEB in the rate application.

Capital Funding Options

During the IRM period, it is expected that a utility should manage both its capital and operating expenses to service current and new customers while maintaining its financial viability and delivering productivity improvements, in line with the "inflation less productivity" Price Cap IR adjustment. However, capital investments can be "lumpy". To preserve the efficiency of the IRM process and avoid early rebasing or inefficiently timed capital investments aligned with the cost of service rebasing application, the OEB has provided for capital tracker mechanisms (e.g. the Incremental Capital Module and the Advanced Capital Module developed for electricity distributors). These allow for approval and funding recovery of qualifying capital investments during the IRM period between cost of service rebasing where material capital investments that are beyond what is normally funded through rates can be reviewed and approved without requiring an early rebasing. The ICM was established in 2008 as part of the 3rd Generation IRM, but it and the ACM have evolved as a result of the OEB's review. The OEB's policies on the ICM and ACM are documented in two OEB reports.[20]

Natural Gas Demand Side Management (DSM) Costs

Natural gas distributors may apply to the OEB for funding to support the design and delivery of broad-based DSM plans. The OEB's policy document for gas utility DSM plans (the DSM Framework[21]) provides the basis for any application that seeks approval of amounts related to DSM programs. Natural gas distributor DSM plans are made up of individual programs for certain customers and are aimed to reduce overall natural gas

[19] *Report of the Board: Transition to International Financial Reporting Standards*, July 28, 2009 and *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, June 13, 2011.
[20] *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 and *Report of the OEB - New Policy Options for the Funding of Capital Investments: Supplemental Report*, January 22, 2016
[21] EB-2014-0134

consumption and increase the efficiency of equipment and technologies that use natural gas. OEB-approved DSM funding, which is used to support program design, delivery, implementation, marketing and administration, is approved by the OEB under Section 36 and is recovered by the gas utility from its customers through distribution rates.

Electricity Conservation and Demand Management (CDM) Costs

Electricity distributors may apply to the OEB for CDM funding for the purpose of deferring the capital investment for specific distribution infrastructure. The OEB's policy document for electricity distributor CDM (the CDM Requirement Guidelines[22]) provides guidance for electricity distributors seeking approval of any such proposal. Electricity distributors may pursue activities such as electricity conservation and energy efficiency programs, demand response programs, energy storage programs and programs aimed at reducing distribution losses. The primary goal of these activities must be for the purpose of deferring the capital investment for specific distribution infrastructure. Any OEB-approved funding is provided under Section 78 and is recovered by the electricity distributor from its customers through distribution rates. For all other CDM related programs, including general customer-focused electricity conservation and energy efficiency programs, electricity distributors must enter into contractual agreements with the IESO. These programs are not funded through distribution rates

Cost Allocation

Cost allocation is the process used to determine how a distributor's total revenue requirement will be attributed to each customer class. The guiding objective is to allocate costs to the customers that cause the costs to be incurred. Although highly technical in nature, cost allocation also requires significant judgement.

The OEB's cost allocation policies for electricity distributors have evolved over the years and have emphasized a consistent approach across all distributors.[23] The OEB has established principles and approaches which address many of the issues which arise during the cost allocation process. Electricity distributors are encouraged to include cost allocation proposals which conform to the OEB's established policies. An electricity distributor (or any other party to a proceeding) may propose an alternative approach, but must provide sufficient evidence and analysis to support a determination that the alternative is a superior approach in the circumstances.

[22] EB-2014-0278
[23] *Report of the Board: Review of Electricity Distribution Cost Allocation Policy*, March 31, 2011.

Natural gas utilities, electricity transmitters, and OPG should support their cost allocation proposals with appropriate rationale, based on the OEB's historical approach to cost allocation issues for these utilities. Natural gas utilities, where applicable, must provide information on its regulated and unregulated storage operations and a description of the allocation of costs between regulated and unregulated storage.

Cost of Capital

Utilities have the opportunity to recover their cost of capital through their rates. The OEB sets the cost of capital using a formula-based approach, which has streamlined the regulatory process considerably.[24] The same approach is used for all utilities, and the results are predictable, stable and fully transparent. The general expectation is that the cost of capital parameters will remain unchanged throughout the rate-setting term, typically 5-years.

A utility applying for cost of capital under the OEB's policy is not required to provide supporting evidence for its return on equity proposal. The onus is on other parties to provide evidence to demonstrate that the policy should not apply. Support must be provided for debt costs proposals. A utility (or any other party to a proceeding) may propose alternative approaches, but must provide sufficient evidence and analysis to support a determination that the alternative is appropriate in light of the utility's circumstances.

Depreciation

Depreciation is the return of invested capital over the useful lives of these assets. Depreciation is a significant component of a utility's revenue requirement. While the calculation of depreciation expense can be a relatively mechanistic exercise resulting from assets in service and forecast to be in service, it relies on an appropriate study of the useful lives and componentization of the utility's assets[25]. This study will form an important supplementary part of the utility system plan. A utility can use a third-party for its depreciation study, but is not required to do so unless ordered by the OEB.

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[24] *Report of the Board on the Cost of Capital for Ontario`s Regulated Utilities,* December 11, 2009 and OEB Staff Report: Review of the Cost of Capital for Ontario's Regulated Utilities, January 14, 2016 and associated OEB cover letter.

[25] Information that the OEB expects electricity distributors to consider is contained in the OEB's letter regarding *Depreciation Study for Use by Electricity Distributors, Consultant Final Report EB-2010-0178 – Transition to International Financial Reporting Standards* and the associated report by Kinectrics Inc. titled Asset Depreciation Study for the Ontario Energy Board, July 8, 2010 and the OEB's letter regarding *Regulatory Accounting Policy Direction Regarding Changes to Depreciation Expense and Capitalization Policies in 2012 and 2013,* July 17, 2012.

Regardless of how the work is completed, the study must be supported by high quality evidence and a thorough analysis that can be rigorously tested.

Natural Gas System Expansion

The OEB has issued specific guidelines for natural gas utilities' transmission and distribution system projects. The OEB's *Report on the Expansion of Natural Gas System in Ontario*, the E.B.O. 134 Report, forms the basis of the filing requirements on the economic feasibility tests to be applied to leave to construct applications for pipeline transmission projects. A natural gas utility must provide information of transmission projects in its capital plan and provide an assessment of the potential impacts of the proposed natural gas pipeline(s) on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of costs, rates, reliability and access to supplies.

The OEB issued its *Final Report of the Board and the Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario* (E.B.O. 188) in January 1998. This report provides the criteria under which the OEB assesses the overall economic feasibility of distribution system expansion projects. A key principle of the guidelines is that existing ratepayers should be held harmless from rate impacts resulting from the cost of new connections. A utility as part of its capital plan must provide an assessment of all its distribution system expansion projects as per the *E.B.O. 188 Guidelines* and demonstrate that existing customers will be held harmless from the proposed distribution system expansion projects. This policy is currently under review by the OEB under proceeding EB-2016-0004.

Rate Design

Once costs are allocated to a particular customer class, rate design is the process used to develop the specific structure of rates to recover those costs. Although highly technical in nature, rate design also requires significant judgement and the consideration of broader rate setting principles in order to ensure fairness for customers and public interest outcomes.

The OEB's rate design policies for electricity distributors have evolved over the years and have emphasized a consistent approach across all distributors. The OEB has established principles and approaches which address many of the issues which arise during the rate design process. The OEB has also developed specific approaches to a number of specific rate design issues. One recent example is the change to residential rate design. The OEB's policy to re-design residential electricity distribution rates to be a fixed charge will enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services. It is also a fairer way to recover the costs of providing electricity distribution service.[26]

Rate Mitigation

The OEB expects utilities to mitigate bill impacts through the pacing and prioritizing of investments and activities. For electricity distributors, the OEB has a policy requiring the filing of a mitigation plan when the total bill impact is 10% or more for any customer class. The OEB expects all other utilities to propose mitigation plans, or explain why a plan is not required, when their proposals result in material impacts to customers[27].

Rate-setting Policies for Consolidations

On March 26, 2015 the OEB issued its *Report of the Board: Rate-Making Associated with Distributor Consolidation*. To encourage consolidations, the OEB established a policy that consolidating entities could defer rebasing for up 10 years. For electricity distributors deferring rebasing beyond five years, an earnings sharing mechanism (ESM) is required above ±300 basis points. The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.

Under the ESM, excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. Earnings will be assessed each year once audited financial results are available and excess earnings beyond 300 basis points will be shared with customers annually. No evidence is required in support of an ESM that follows the form set out in the OEB's reports.

To encourage consolidation, the OEB also extended the availability of the ICM for consolidating distributors that are on Annual IR Index, thereby providing consolidating distributors with the ability to finance capital investments during the deferral period without being required to rebase earlier than planned.

On January 19, 2016 the OEB issued the *Handbook to Electricity Distributor and Transmitter Consolidations* (the MAADs Handbook). The MAADs Handbook provides

[26] *Board Policy: A New Distribution Rate Design for Residential Electricity Customers*, April 2, 2015.

[27] The OEB's August 14, 2014 Decision on the quarterly rate adjustment mechanism process for natural gas distributors (EB-2014-0199), determined that advance notification to customers would be required going forward and a mitigation plan must be filed if a 25% or greater change is anticipated on the commodity portion of a typical residential system supply customer's bill.

guidance to applicants and stakeholders on how the OEB will review applications for consolidation.

Working Capital Allowance

The (cash) working capital is the amount of cash that the utility requires to cover cash outlays in advance of when it recovers these amounts from customers. The working capital allowance is the allowance for this minimum amount of cash, reflected as capital not otherwise available for investment in assets that is factored into the determination of rate base.

The cash working capital requirements or working capital allowance is traditionally determined through a study that examines cash outlays and cash receipts and the leads and lags between the outlays and receipts.

For electricity distributors, the OEB currently allows for a working capital allowance of 7.5% of total operating expenses plus the cost of power[28] A distributor may propose an alternative which must be supported by a lead-lag study. Natural gas distributors, transmitters and OPG use utility-specific working capital allowances based on studies.

[28] The OEB letter regarding the *Allowance for Working Capital for Electricity Distribution Rate Applications*, June 3, 2015, provided an update to the OEB's policy for the calculation of the allowance for working capital for electricity distribution rate applications.