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

Ontario Energy Board

Filing Requirements For
Natural Gas Rate Applications

February 16, 2017

CHAPTER 1 OVERVIEW

CHAPTER 2 COST OF SERVICE APPLICATIONS

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Natural Gas Rate Applications

Chapter 1

Overview

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Chapter 1 Overview

1.0 Introduction

This document provides information about the filing requirements for a natural gas utility's cost of service rate application. It is designed to provide direction to applicants, and it is expected that applicants will file their applications consistent with the filing requirements. If circumstances warrant, the OEB may require an applicant to file evidence in addition to what is identified in the filing requirements.

These filing requirements are based on the rate setting policy described in the OEB's *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Report) and the October 13, 2016 *Handbook for Utility Rate Applications* (the Rate Handbook). The Rate Handbook outlines how the RRFE principles will be applied to all regulated utilities going forward (natural gas utilities, electricity distributors, electricity transmitters and Ontario Power Generation). The framework is now referred to as the Renewed Regulatory Framework (RRF) to reflect this transition.

Going forward, there will be two rate-setting policies available for natural gas utilities: Price Cap Incentive Rate-setting (Price Cap IR) and Custom Incentive Rate-setting (Custom IR). The requirements of Chapter 1 are applicable to both rate setting methods.

Together with the Rate Handbook, these filing requirements supersede the *Minimum Filing Requirements for Natural Gas Distribution Cost of Service Applications* dated November 20, 2005. Substantively, they are intended to consolidate all of the significant components of the 2005 filing requirements with additional requirements related to the objectives of the RRF so that the updated filing requirements applicable to natural gas utilities are reasonably aligned with the filing requirements applicable to electricity utilities.

Unless specifically identified, the words "utility", "utilities", "applicant" or "applicants", in this document refer to natural gas utilities.

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

Chapter 1 outlines generic procedural matters and the expectations of the OEB for parties participating in rate-setting processes.

Chapter 2 details the filing requirements for natural gas utilities filing a cost of service application under the Price Cap IR method.

1.1 Completeness and Accuracy of an Application

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

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

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

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

1.2 Certification of Evidence

An application filed with the OEB must include a certification by a senior officer of the applicant that the evidence filed is accurate, consistent and complete to the best of his or her knowledge.

1.3 Updating an Application

When changes or updates to an application or supporting evidence are necessary, applicants must follow the requirements of Rule 11 of the *Rules of Practice and Procedure* (the Rules). When these changes or updates are contemplated in later stages of a proceeding, updates should only be made if there is a material change to the evidence.

1.4 Interrogatories

The OEB is aware of the number of interrogatories that the regulatory review process can generate. The OEB advises applicants to consider the clarity, completeness and accuracy of their evidence in order to reduce the need for interrogatories. Furthermore, the OEB expects that applicants and other parties filing evidence will file appropriate, relevant, accurate and complete evidence. A sub-standard or inaccurate application, and the re-filing or updating of evidence can extend the time for the OEB's review. Applicants should not file information that they consider not relevant to the proceeding. The OEB also advises all parties to carefully consider the relevance and materiality of information before requesting it through interrogatories.

The OEB reminds parties not to engage in detailed exploration of items that do not appear to be material. The guidance for variance explanations documented in Chapter 2 of the filing requirements should be taken into consideration by the parties. In making its decision on cost awards, the OEB will consider whether or not intervenors made reasonable efforts to ensure that their participation in the hearing was focused on material issues.

Parties should consult Rules 26 and 27 of the OEB's Rules for additional information on the filing of interrogatories and responses, and matters related to such filings.

1.5 Confidential Information

The OEB relies on full and complete disclosure of all relevant material in order to ensure that its decisions are well-informed. To ensure a transparent and accessible rate review process, applicants should make every effort to file all material publicly and completely. However, the OEB's Rules and the *Practice Direction on Confidential Filings* (the

Practice Direction) allow applicants and other parties to request that certain evidence be treated as confidential. Where such a request is made participants are expected to review and follow the Practice Direction.

The OEB and parties to a proceeding are required to devote additional resources to the administration, management and adjudication of requests for confidentiality and confidential filings. Parties must ensure that filings for which they request confidential treatment are both relevant to the proceeding and genuinely in need of confidential treatment. A list of the types of information that the OEB has previously assessed or maintained as confidential is set out in Appendix B of the Practice Direction. This list is illustrative only, and the OEB will make a determination on the merits of each request for confidentiality.

When dealing with confidential information, parties should also take note of the requirements related to relevance and materiality of interrogatories outlined in this chapter. To reduce the administrative issues associated with the management of those filings, the OEB expects that parties will minimize, to the extent possible, requests for confidential information.

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Filing Requirements For
Natural Gas Rate Applications

Chapter 2

Cost of Service Applications

February 16, 2017

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Chapter 2 Cost of Service Applications

2.0 General Requirements

The purpose of this document is to establish filing requirements for cost of service rate applications by gas utilities. The filing requirements have been established to require complete and transparent information sufficient to inform the OEB and interested parties of all material facts related to its distribution, storage and/or transportation of gas.

The two rate-setting options for natural gas utilities based on the methods outlined in the RRF and the *Handbook for Utility Rate Applications* (the Rate Handbook) are as follows:

- A price cap incentive rate-setting plan of five years. Under this methodology, base rates are set through a cost of service process for the first year and then adjusted in years two to five using a formula specific to each year (Price Cap IR).

- A custom incentive rate-setting plan which sets rates for a minimum of five years considering a minimum 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 (Custom IR).

Existing natural gas utilities are expected to select either the Price Cap IR or the Custom IR option once any OEB-approved rate-setting plans have expired. New entrants are expected to select from these two options when filing the first rate application with the OEB.

2.0.1 Relevant Chapters

Applicants should review Chapter 1 of the filing requirements. Chapter 1provides an overview of the OEB's expectations on generic matters, such as the completeness and accuracy of an application, the treatment of non-material items, and confidential filings.

These Chapter 2 filing requirements provide the information necessary for a complete cost of service application under the Price Cap IR option. In addition to these filing requirements, applicants must consult the Rate Handbook, which together supersede the 2005 filing requirements.

A Price Cap IR application must include a proposed mechanism for the incentive rate-setting period (years two to five) based on the minimum standards outlined in Exhibit 10.

A Custom IR application is by its very nature unique and 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 the Rate Handbook regarding the evidence to support the application.

2.0.2 Separation of Utility Function

Utilities are rate regulated by the OEB on a stand-alone basis, which means that the application must relate to the regulated entity, separate from a parent company or any other affiliate not regulated by the OEB. It is important that only the amounts attributable to the regulated utility be included when determining costs to be recovered in rates, such as taxes, debt and the cost of affiliate transactions.

2.0.3 Cost of Service Application Before Expiry of IR Term

Natural gas utilities that are within the term of a Price Cap IR plan and are planning to file a cost of service application earlier than scheduled must meet the threshold for early rebasing established for electricity distributors in the OEB's letter of April 20, 2010.

The letter established that a utility seeking to have its rates rebased in advance of its next regularly scheduled cost of service proceeding, must justify in its cost of service application why an early rebasing is required. The justification may include the OEB's prior approval of an off-ramp condition.

Specifically, the utility would be expected to demonstrate clearly why and how it could not adequately manage its resources and financial needs during the remainder of its IR plan period. The letter further advised utilities that the OEB may consider it appropriate to determine, as a preliminary issue, whether the application for rebasing is justified or whether the application as framed should be dismissed. Utilities were also advised that the OEB might, where an application for early rebasing did not appear to be justified, disallow some or all of the regulatory costs associated with the preparation and hearing of that application.

2.0.4 Late Filing of Application

Natural gas utility cost of service rate applications are expected to be filed one year prior to the proposed effective date of the new rates. The effective date of rates approved for applications filed after the required date may be later than the effective date proposed.

Late applications filed after the commencement of the rate year for which the application is intended will not be accepted by the OEB. For example, an application to set rates commencing January 1, 2019 not filed by December 31, 2018 (the last business day before the commencement of the rate year) should be converted to a 2020 rate application. This means that the intended 2019 test year becomes the bridge year and the applicant should provide a 2020 budget to underpin an updated test year. In this instance, the OEB expects that a utility will not seek any further rate adjustment for the 2019 rate year but will remain operating under the rates set for 2018 (unless the OEB has approved an alternative mechanism).

2.0.5 Structure of Application

An application for a forward test year cost of service filing must include the following ten exhibits:

Exhibit 1	Administrative Documents
Exhibit 2	Rate Base (includes the Utility System Plan)
Exhibit 3	Operating Revenue
Exhibit 4	Operating Expenses
Exhibit 5	Cost of Capital and Capital Structure
Exhibit 6	Revenue Sufficiency/Deficiency
Exhibit 7	Cost Allocation
Exhibit 8	Rate Design
Exhibit 9	Deferral and Variance Accounts
Exhibit 10	Incentive Rate-setting Proposal

Additional exhibits may be included in an application in support of other proposals for which the applicant is seeking OEB review and approval. Generally, data models and spreadsheets are filed in cost of service applications where applicable in support of an applicant's proposals. All models, spreadsheets and tables must be filed in live Microsoft Excel format. In circumstances where this is not feasible or reasonable, utilities must provide an explanation.

Applicants must isolate delivery-related sufficiency/deficiency separate and apart from the commodity-related sufficiency/deficiency. Additional information is provided in Exhibit 6.

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

- Written direct evidence should be included before data schedules
- Average in-service fixed assets for test year items in rate base
- Total capitalization (debt and equity) must equate to total rate base

- Data for the following years, at a minimum, must be provided:
  - Test year = prospective rate year
  - Bridge year = current year
  - Four most recent historical years (or number of years necessary to provide actuals back to and including the most recent OEB-approved test year, but not less than four years)
  - Most recent OEB-approved test year
- Documents are to be provided in bookmarked and text-searchable Adobe PDF format

If an applicant updates its evidence during the proceeding, it must ensure that such updates are submitted in accordance with Rule 11 of the OEB's *Rules of Practice and Procedure* which address amendments to the evidentiary record and new information.

2.0.6 Variance Explanations

The applicant must provide justification for annual changes to its rate base, capital expenditures, and operations, maintenance and administration costs. To ensure the OEB's review is focused on matters that are material, the OEB only requires variance explanations for changes above certain amounts.

The thresholds differ for each applicant, depending on the magnitude of the revenue requirement. A written explanation is required for rate base, capital expenditures, and operations, maintenance and administration costs if the revenue requirement impact of variances exceeds the applicable utility-specific threshold as follows:

- $50,000 for a utility with a revenue requirement less than or equal to $10 million
- 0.5% of revenue requirement for a utility with a revenue requirement greater than $10 million and less than or equal to $200 million
- $1 million for a utility with a revenue requirement of more than $200 million

An applicant may provide additional details if it determines that this would assist the OEB with its review of the application. Utilities are reminded that the onus is on the applicant to make its case and ensure that the OEB has the information it needs to adequately assess and deliberate on the application.

2.0.7 Accounting Standards

Most utilities regulated by the OEB were required to adopt International Financial Reporting Standards for financial reporting by January 1, 2015. In the *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, the OEB indicated that it would require utilities to explain the use of an accounting standard other than modified International Financial Reporting Standards (MIFRS). On this basis, the following accounting standards may be applicable to natural gas utilities for 2015 and beyond:

- International Financial Reporting Standards (IFRS)
- United States Generally Accepted Accounting Principles (USGAAP)
- Accounting Standards for Private Enterprise (ASPE)

Applications filed using Canadian Generally Accepted Accounting Principles (CGAAP) will no longer be accepted.

The accounting standard that is used as the basis of the application must be clearly stated, including the date of its adoption by the utility. If the applicant has changed its accounting standard from the accounting standard used in its previous rebasing application, the applicant must explain the reason for the change. The applicant must also discuss and quantify the impact of the change to the affected elements of the revenue requirement and overall application.

Irrespective of the accounting standard used in the application, the applicant must provide a summary of changes to its accounting policies made since the applicant's last rebasing application (e.g. capitalization of overhead, capitalization of interest, depreciation, etc.). Revenue requirement impacts of any changes in accounting policies must be separately quantified.

2.0.7.1 Modified IFRS Application

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

- *Report of the Board: Transition to IFRS;* dated July 28, 2009
- *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment*, dated June 13, 2011

For those applicants that have adopted IFRS for financial reporting purposes, rate applications must be filed on the basis of MIFRS.

2.0.7.2 USGAAP or ASPE Application

Applicants should refer to the documents listed in the preceding section (2.0.7.1) for guidance relating to the use of USGAAP or ASPE in application filings. Per the Addendum Report, references to IFRS and MIFRS in these documents should include USGAAP or alternate accounting standards.

The OEB requires a utility that adopts USGAAP or ASPE in its first rate application following the adoption of the new accounting standard, to provide the following:

- Evidence of the eligibility of the utility under the governing securities legislation to report financial information using that standard (if applicable)
- A copy of the authorization to use the standard from the corresponding Canadian securities regulator (if applicable)
- Evidence demonstrating the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation

If the applicant has received approval from the OEB to use USGAAP or ASPE in a previous proceeding, the order should be filed (or referenced). The applicant must also provide evidence regarding the continued eligibility of the utility under the governing securities legislation to report financial information using that standard.

2.1 Exhibit 1: Administrative Documents

The items identified in this Exhibit provide the background and summary to the application and are grouped into the following sections:

1) Table of Contents
2) Executive Summary
3) Administration
4) System Overview
5) Application Summary
6) Customer Engagement
7) Performance Measurement
8) Financial Information
9) Utility Consolidations

2.1.1 Table of Contents

The application must contain a Table of Contents listing the major sections and subsections of the application, including the exhibit list. The electronic version of the application must be appropriately bookmarked to provide direct access to each section and subsection of the Table of Contents.

2.1.2 Executive Summary

The applicant has an opportunity in this section to identify the key elements of its application and provide the OEB with a broad overview of the utility, including its past and expected performance and future plans. The purpose of the Executive Summary is distinct from the Application Summary (see section 2.1.5).

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

Accordingly, a utility must provide plain language information about its objectives and business plan, how these relate to what is being sought in the application and how it aligns with the Rate Handbook. The applicant must include a discussion of bill impacts. The summary should also describe whether and how a distributor's objectives have changed, and how the plan to deliver on certain goals reflects customer feedback. This information will allow the OEB to understand the impacts of the business plan in key areas of the application such as customer service, system reliability, costs, and bill impacts.

2.1.3 Administration

This section must include the following:

1) Identification of the utility's primary contact for the application including name, address, phone number, fax and email address. This person will be the OEB's communication contact during the proceeding.
2) Identification of any legal or other representation for the application.
3) Link to the location on the applicant's internet site where the application and related documents will be accessible, and any social media accounts used by the applicant to communicate with its customers.
4) The number and percentage of customer email addresses retained by the applicant, by customer class for which the applicant may use to communicate a notice of application.
5) The date by which the applicant would require on-bill or bill insert information to ensure inclusion in the next billing cycle.
6) One or more proposed locations within the service area(s) of the utility for community meetings. Central, informal locations that are accessible are preferred.
7) A statement of where the notice of hearing should be published and the rationale for why the stated publication(s) is/are appropriate. The OEB has a new publication process, but still requires the applicant's recommendation regarding publication.

8) Bill impacts to be used for the notice of application for a typical residential and small commercial customer. A utility may also include and propose bill impacts for alternative consumption profiles and customer groups as appropriate given the consumption patterns of its customers.

9) Applicants must identify proposals in the application that constitute a change from the status quo and those that will have a material impact on customers, including any changes to rates, charges, or terms of service that may affect discrete customer groups. Applicants must also identify the specific customers or customer groups that will be affected by such proposals to ensure the notice of the application is served appropriately.

10) Applicant's preference for a written or oral hearing with supporting rationale.

11) A brief description of the proposed components of the Price Cap IR method.

12) The requested effective date.

13) A list of any deviations from the filing requirements and Rate Handbook with supporting rationale, or a statement if no deviations.

14) A list of any changes to methodologies used in previous applications.

15) Identification of OEB directions from any previous OEB decisions and/or orders. The applicant must address the status of any directives and clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision).

16) Reference to the utility's Conditions of Service and any other customer-related policies and regulations. The utility does not need to file these policies, but must provide a reference to where its policies are publicly available (e.g., on the utility's website), and confirm that these are the current versions. A description of any changes that have been made since the last cost of service application must also be provided. If any policies would change as a result of approval of the application, the utility must also identify all such changes.

17) A confirmation must be provided that there are no rates or charges listed in the Conditions of Service or other policies and regulations of the applicant that are not on the utility's rate schedules.

18) A description of the corporate and utility organizational structure, the composition of the utility company's Board of Directors and a description of the reporting relationships between management of the utility and parent company. Include a corporate entities relationship chart and an organization chart for the regulated utility. In addition, include any planned changes in corporate or utility structure, and any planned changes in legal organization and control.

19) List of requested approvals and accounting orders.

20) A draft Issues List.

2.1.4 System Overview

This section must provide a summary description of the applicant's system assets and service area. It must include a general description and map of the applicant's assets and operations, showing where the utility operates within the province, and the communities it services. A franchise map should also be included clearly showing each franchise held. The applicant may provide more detailed geographic and/or engineering maps indicating planned capital expansion or replacement programs. This section must also identify the location of gas transportation assets, compressor stations, major meter stations, underground storage facilities, Liquefied Natural Gas facilities, operations centers, interconnects, and any other significant assets.

The system overview is distinct from the Utility System Plan required in Exhibit 2.

2.1.5 Application Summary

At a minimum, a summary of the items listed below must be provided.

Revenue Requirement

- Revenue requirement requested for the test year
- Increase/decrease ($ and %) from previously approved revenue requirement
- Revenue deficiency or sufficiency
- Schedule of main drivers of revenue requirement and deficiency/sufficiency changes from the last OEB approved year

Budgeting and Accounting Assumptions

- Economic overview (such as growth and inflation)
- Identification of accounting standard used for each year and brief explanation of impacts resulting from any change in accounting standard

Throughput Forecast

- Throughput and throughput growth for the test year (percentage change from last OEB-approved)
- Customer numbers and changes in customer count, average and year-end
- Brief description of forecasting method(s) used

Rate Base and Utility System Plan

- Rate base requested for the test year
- Change in rate base from last OEB approved ($ and %)

- Capital expenditures requested for the test year
- Change in capital expenditures from last OEB approved ($ and %)
- Summary, key elements, and main drivers of the applicant's capital investment plan

Operations, Maintenance and Administration (OM&A) Expense

- OM&A for the test year and the change from last OEB approved ($ and %)
- Summary of overall drivers and cost trends
- Inflation rates used for OM&A forecasts
- Total compensation for the test year and the change from last OEB approved ($ and %)
- Summary of any proposed gas supply, transportation and storage costs
- Summary of any changes in depreciation rates

Cost of Capital

- A statement as to the use of the OEB's cost of capital parameters
- Summary and rationale for any deviations from the OEB's cost of capital methodology
- The weighted average cost of capital proposed in the application, and a summary breakdown of the proposed rates for each component of capital financing:
    - Return on equity
    - Return on preferred shares
    - Weighted average cost of long-term debt
    - Cost of short-debt debt

Cost Allocation and Rate Design

- Summary of any deviations from OEB-approved cost allocation and rate design methodologies, including any changes to miscellaneous service charges
- Summary of any new proposals
- Summary of any significant changes proposed to revenue-to-cost ratios and fixed/variable splits
- Summary of any proposed mitigation plans to address rate impacts on specific customer classes or overall rate impact

Performance and Reporting

- Scorecard proposal and a brief explanation of the performance results and drivers for the last five years for measures that contain historical data
- Summary of any reporting requirements proposed
- Description of how the applicant has addressed the Service Quality

Performance and Measurement requirements as outlined in the OEB's *Gas Distribution Access Rule* (GDAR).
- Discussion of any outstanding areas of non-compliance and the effect they have had on the application, including any relief sought

Bill Impacts
- Summary of total bill impacts ($ and %) for typical or average customers in all customer classes

Deferral and Variance Accounts
- Accounts requested for disposition including account balances, disposition methodology and timing
- Any new deferral and variance accounts requested and any request for the discontinuation of existing accounts

Rate Schedules
- Summary of any other changes to the current OEB-approved rate schedules that are being proposed in the new rate schedules, which are filed and discussed in Exhibit 8

Incentive Rate-setting
- Summary of the key components proposed for the Price Cap IR method for the incentive rate-setting period

2.1.6 Customer Engagement

The Rate Handbook states that 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.

The OEB expects natural gas utilities to provide an overview of customer engagement activities undertaken and how their customer's needs, preferences and expectations have been reflected in the elements of the application.

Applicants should specifically discuss how they informed their customers of the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e. costs, benefits and the impact on rates that customers would face). The application should discuss any feedback provided by customers and how this feedback shaped the final application. This analysis must encompass all customers, including direct purchase, transportation, and storage customers.

Applicants should also reference any communications sent to customers about the application, such as bill inserts, or town hall meetings and other forms of outreach undertaken to engage customers. Applicants should document how the proposals were explained to customers and how the application serves customers' needs and expectations. Applicants should document the feedback heard from customers through these engagement activities.

It is the OEB's expectation that utilities identify explicitly the outcomes of customer engagement in terms of the impacts on the utility's plans, and how that information has shaped the rate application. Natural gas utilities may find Appendix 2-AC (Customer Engagement Activities Summary) from the electricity distribution filing requirements (or any successor document) helpful in structuring this evidence.

This section must also include all responses to matters raised in letters of comment filed with the OEB during the course of the proceeding, when available.

The planning elements of customer engagement activities are to be filed as part of the Utility System Plan, under Exhibit 2.

2.1.7 Performance Measurement and Scorecard

The Rate Handbook established that the OEB's scorecard approach to performance measurement will be applied to natural gas utilities. Each utility is required, in its first rate application following the issuance of the Rate Handbook, to propose a scorecard that will be used to measure and monitor its performance and, where appropriate, enable comparisons between or among gas utilities. The OEB may modify existing utility scorecards from time to time to reflect its continuing development of performance assessment metrics and to maintain scorecard consistency among utilities.

The format of the proposed scorecard should be similar to the scorecard developed for electricity distributors (available on the OEB's website) and must include measures for customer focus, operational effectiveness, public policy responsiveness, and financial performance. In the scorecard proposal, the applicant is expected to discuss its plans for continuous improvement. The applicant may propose additional performance categories or measures that it believes would be meaningful for its operations as a natural gas utility. Scorecard reporting is expected during the term of the incentive plan, as the data becomes available.

In creating the scorecard, applicants may wish to consider the data and information they are already required to file under the OEB's GDAR and the OEB's *Reporting and Record Keeping Requirements* (RRR).

Benchmarking will be used by the OEB to review a utility's proposals, including at the program level. Utilities are expected to provide benchmarking analysis which supports their proposed plans and programs and demonstrates continuous improvement. In addition to any analyses or reports previously ordered by the OEB, the Rate Handbook discusses two types of benchmarking that are required in rate applications. These are:

- 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.

The application should discuss how the utility's assessment has informed its business plan and the application.

Any benchmarking, productivity or other related studies must be filed as an appendix to Exhibit 1.

2.1.8 Financial Information

This section must include the following:

- Non-consolidated audited financial statements of the utility (excluding operations of affiliated companies that are not rate-regulated) for the most recent three historical years (i.e. two sets of statements must be filed, which cover three years of historical actuals)[1]. If the most recent final historical audited financial statements are not available at the time the application is filed, draft financial statements must be filed and the final audited financial statements provided as soon as they are available.

- Detailed reconciliation of the financial results shown in the audited financial

[1] The term "non-consolidated audited financial statements" is intended to reflect the current practice followed by Enbridge Gas Distribution Inc., Union Gas Limited and Natural Resource Gas Ltd.

statements and the historical regulatory financial information filed in the application. The reconciliation must include:
  - The separation of regulated and non-regulated businesses
  - The identification of any proposed deviations between the audited financial statements and the regulatory financial information including the identification of any prior OEB approvals for such deviations

- Pro-forma statements for the regulated utility for the bridge and the test year with separate disclosure regarding its operating segments

- Annual report and management's discussion and analysis for the most recent year of the parent company, if applicable

- Rating agency report(s), if available

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

- A description of existing accounting orders and list of any departures from these orders

- Any departures from the Uniform System of Accounts for Class A Gas Utilities

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

- The accounting standard(s) used for general purpose financial statements and when it was adopted

- If an applicant is conducting a non-utility business, such as generation, it must confirm the nature of the accounting treatment it has used to segregate non-utility activities from rate-regulated activities. Applicants owning generation facilities and energy storage facilities should consult the relevant OEB accounting treatment guidelines[2].

2.1.9 Utility Consolidations

In the first cost of service application following a consolidation, the applicant is expected to address any rate-making aspects of the MAADs transaction, including a

[2] G-2010-0030 *Guidelines: Regulatory and Accounting Treatments for Natural Gas Utility-Owned Qualifying Facilities or Assets*, dated February 25, 2010 or any successor document.

rate harmonization plan and /or customer rate classifications post consolidation.

2.2 Exhibit 2: Rate Base (includes the Utility System Plan)

This exhibit must include the following:

1) Rate Base Overview
2) Gross Assets – Property, Plant and Equipment and Accumulated Depreciation
3) Allowance for Working Capital
4) Capitalization Policy
5) Capital Expenditures
6) Utility System Plan (USP)
7) Service Quality and Reliability Performance

2.2.1 Rate Base Overview

For rate base, the applicant must include continuity statements with opening and closing balances for each year for gross fixed assets and accumulated depreciation, and year-over-year variance analyses. Continuity statements must include interest during construction, and overheads. Variance analyses should include a written explanation when there is a variance greater than the amount set out in Section 2.0.6.

At a minimum, the information filed in support of the requested rate base must include data for the historical actuals, bridge year (actuals to date and balance of year as budgeted), and test year.

The applicant must document the method used to calculate the value of average in-service fixed assets for the test year, such as the average of monthly or quarterly values, or the half-year rule. Rate base may also include an allowance for working capital (described below).

If continuity statements have been restated for the purposes of the application (e.g., due to changes in accounting standards or to reflect corrections in historical audited values), the utility must provide a thorough explanation for the restatement and also provide a reconciliation to the original statements.

The following comparisons must be provided:

- Historical OEB-approved vs. historical actual (for most recent OEB-approved years)
- Historical actual vs. preceding year historical actual
- Historical actual vs. bridge
- Bridge vs. test year

The opening and closing balances of gross assets and accumulated depreciation that are used to calculate the fixed asset component of rate base must correspond to the respective balances in any fixed asset continuity statements. In the event that the balances do not correspond, the applicant must provide an explanation and reconciliation.

This reconciliation must be between or among the last actual year, bridge year and any test year net book value balances reported on a fixed asset continuity schedule and the balances included in the rate base calculation. Examples of adjustments that would be made to the fixed asset continuity schedule balances for rate base calculation purposes are the removal of the amounts for work in progress and any asset retirement obligations.

When proposed capital expenditures are related to projects which require a contribution from customers, such amounts should be shown separately as an offset to rate base.

The fixed asset continuity schedule and supporting data must be filed in Microsoft Excel format.

2.2.2 Gross Assets – Property, Plant and Equipment and Accumulated Depreciation

The applicant must provide the following information:

- Breakdown by function (distribution plant, storage plant, transportation plant, general plant, other plant) for required statements and analyses
- Detailed breakdown by major plant account for each functionalized plant item
    - For the test year, each plant item must be accompanied by a description
- Detailed breakdown of the capital additions for the test year
- Summary of any capital adjustment(s), including what was approved and what was spent, if the utility received approval for a capital factor adjustment as part of a previous application
- Reconciliation of continuity statements to the calculated depreciation expenses, reported under Exhibit 4 – Operating Expenses, and presented by asset account
- Identification and detailed explanations for any asset disposals, asset retirement obligations, site restoration costs or asset utilization impacts

2.2.3 Allowance for Working Capital

If an applicant is proposing to include a working cash allowance in rate base, it must support this with a lead/lag study, provide the date when the lead/lag study was prepared, and when it was last formally reviewed and approved by the OEB. A lead/lag study for two time periods is required, namely:

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

Other working capital items may include:

- Gas in inventory
- Supplies and materials
- Prepaid expenses
- Miscellaneous accounts receivable
- Security deposits

For each of the items, a calculation of the average of monthly averages ($ for each and volumes for gas in inventory) must be provided.

2.2.4 Capitalization Policy

The applicant must provide its capitalization policy. Irrespective of the accounting standard used, if the utility has changed its capitalization policy since its last rebasing application, it must explain the changes and the causes of the changes. 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.

2.2.4.1 Capitalization of Overhead

Irrespective of the accounting standard used in the application, the applicant must provide information on overhead costs on self-constructed assets, including a breakdown of the amounts capitalized year over year. Any changes to the overhead capitalization methodology must be explained.

2.2.4.2 Burden Rates

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

2.2.5 Capital Expenditures

The applicant must provide a summary of capital expenditures over the past five historical years, which would include the bridge year, and five future years including the test year, showing capital expenditures, treatment of contributed capital and additions, and treatment of Construction Work in Progress.

- Detailed explanation of the key drivers of capital expenditure increases for the test year, by capital expenditure category
- Proposed capital expenditures by investment category, with a reconciliation showing the contribution of these aggregated amounts to the applicant's total capital budget for each category
- Written explanation of variances, including that of actuals versus the OEB-approved amounts for the applicant's last OEB-approved rebasing application
- The proposed accounting treatment, including the treatment of the cost of funds, for investments spanning more than one year

2.2.6 Utility System Plan (USP)

This section will consist of a consolidated utility system plan, including an asset management plan. All elements of the utility system plan must be contained in one integrated document that contains each of the prescribed components. The USP must contain all elements in one integrated and cohesive document. The USP must be filed as a stand-alone and self-sufficient document within this section of Exhibit 2.

The natural gas system encompasses regulated above and below-ground assets which can include distribution, storage, and transportation system assets. The USP must include all applicable elements from the Rate Handbook and the OEB's guidelines for natural gas utilities' transportation and distribution system projects (E.B.O. 134 and E.B.O. 188)[3].

The USP must include the following:

[3] *Report on the Expansion of Natural Gas System in Ontario* (E.B.O. 134) and the *Final Report of the Board and the Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario* (E.B.O. 188).

- A description of the utility's investment planning process
- The engineering plan for the utility, including the overall plan for capital investments
- The longer term economic and planning assumptions, including expectations of natural gas prices
- The asset management plan (see below)
- A description of how investments are selected and prioritized
- Highlights of recent and proposed investments and the relationship to the engineering plan
- A description of how the needs of customers and overall system planning policy objectives are being reflected, including obligations stemming from Ontario Government policy including the facilitation of a cap and trade framework, relevant greenhouse gas (GHG) legislation, Demand Side Management (DSM) programs and consideration of the OEB's statutory objectives, as applicable
- Linkages to the gas supply plan
- Linkages and trade-offs between capital projects and ongoing OM&A spending

The applicant must also include a discussion of how cost benchmarking studies or utility cost comparisons conducted by or for the applicant are used to support the applicant's proposed expenditures. A description of quantifiable continuous improvements, cost savings or efficiency gains that are expected to be achieved over the Price Cap IR term must be provided and the means by which those improvements, savings and efficiencies will be achieved.

The following information should be provided by the applicant in the USP on a project specific basis, grouped appropriately. Where a program or initiative includes numerous similar projects across a portfolio of similar assets, the evidence can be presented on a program or portfolio basis.

- For projects or programs not subject to a leave to construct application:
    - Need, scope, and purpose of project or program, related customer attachments, capital costs, as well as any applicable cost-benefit analysis
    - A discussion of the relative benefits and costs of the capital and non-capital alternatives considered and rejected in favour of the proposed project or program
    - Detailed information on the priority of the project or program relative to other investments and risks of deferring or not proceeding with the project or program
    - For any renewal investment, details on the change in condition and service life of the asset(s) expected to be achieved by the proposed expenditure
    - Detailed breakdown of the construction milestone dates and in-service dates

  - for each project or program
  - Information on the basis for the budget estimate by project or program (e.g. historical cost, preliminary engineering estimates, request for proposals)
  - Explanation of how the project or program links directly to the asset management plan
  - In service date for each planned capital project
  - Contingency costs and the basis for determining the contingency amounts

- A brief summary of the evidence for any project that requires leave to construct approval under the OEB Act

- Information on customer additions and PI values

- Identification of any project that has been undertaken in relation to a directive issued by the Minister of Energy to the OEB

- Identification of any project that is going into service during the IR term for which the utility is considering requesting capital factor treatment if such a mechanism is being proposed as part of Exhibit 10

2.2.6.1 Asset Management Plan

The natural gas utility must file an asset management plan as a component of the utility system plan. The plan should include the utility's asset management policy, strategy and objectives, an inventory and assessment of the condition of all capital assets or asset categories whose net book value is material, and how this information is used to plan for new and renewal capital, and maintenance expenditures.

The Rate Handbook describes the asset management process as the systematic approach a utility uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the utility'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 plan should demonstrate how these elements produce an integrated capital investment maintenance and retirement plan that will drive capital and maintenance expenditures proposed for the test year and beyond.

2.2.7 Service Quality and Reliability Performance

The applicant must include information for the past five historical years on its service quality performance and measurement requirements as outlined in the OEB's GDAR. A discussion on the reasons for any minimum standards not met must be provided along with a plan for addressing any deficiencies.

The applicant must also discuss its reliability performance over the past five years for matters such as unplanned interruptions and outages and how it has informed it's USP.

2.3 Exhibit 3: Operating Revenue

This exhibit must include evidence on the applicant's forecast of customers, throughput volume, revenue, other revenue, and variance analyses related to these items for historic and test years.

The applicant must provide its customer, volume and revenue forecast, weather normalization methodology, transactional services / storage and transportation revenues, and other sources of revenue in this exhibit. The applicant must include a description of the methodologies and the assumptions used.

All historical data should be weather normalized each year and be presented as both actual and weather normalized.

The evidence in this exhibit should be presented in the following sections:

1) Throughput and Revenue Forecast
2) Accuracy of Throughput Forecast and Variance Analyses
3) Transactional Services / Storage and Transportation Revenue
4) Other Revenue

2.3.1 Throughput and Revenue Forecast

The applicant must provide an explanation of the drivers, assumptions and adjustments underpinning the throughput forecast. All economic assumptions and data sources used in the preparation of the volume and customer count forecast, including expansions and the impact of any demand side management, cap and trade or other GHG reduction-related activities, must be identified and included in this section. Forecasts should include a date of preparation.

The applicant must also provide an explanation of the weather normalization methodology used and indicate in which OEB proceeding approval was granted for its use. All economic models, econometric models, end-use models, customer forecast surveys and other material inputs must also be described and documented.

The applicant must provide a description of how demand side management, cap and trade or any other GHG reduction-related activities affect throughput forecasts in each year of the rate-setting plan.

2.3.2 Accuracy of Throughput Forecast and Variance Analyses

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

- Schedule of throughput volumes, revenues, customer count by rate class, and total system throughput:
  - Historical OEB-approved
  - Historical actual for the past five years
  - Historical actual for the past five years – weather normalized
  - Bridge year
  - Bridge year – weather normalized
  - Test year

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

- Historical OEB-approved vs. historical actual
- Historical OEB-approved vs. historical actual – weather normalized
- Historical actual – weather-normalized vs. preceding year's historical actual – weather-normalized (for the necessary number of years)
- Historical actual – weather normalized vs. bridge year – weather-normalized
- Bridge year – weather-normalized vs. test year

2.3.3 Transactional Services / Storage and Transportation Revenue

The applicant must present five years of actual data including the gross and net margin realized from transactional services activities. The actuals should include year-over-year comparisons to the OEB-approved amounts with explanations for material variances.

The applicant must provide the bridge year and test year revenue forecasts for transactional services activities together with an explanation of the key drivers of the multi-year forecast.

The applicant must present its treatment and mechanics for sharing revenues based on OEB-approved mechanisms and for any new proposals made in the rate application.

2.3.4 Other Revenue

The applicant must provide the following information:

- Comparison of actual revenues for historical years to forecast revenue for the bridge and test years, including explanations for significant variances in year-over-year comparisons
- A list of the specific elements comprising Other Revenue.
- How costing and pricing for other revenues is determined that are not covered under Exhibit 8 with respect to specific miscellaneous service charges
- Any revenue from affiliate transactions, shared services or corporate cost allocations. For each affiliate transaction the applicant must identify the service, the nature of the service provided to affiliated entities, accounts used to record the revenue, and the associated costs to provide the service.

Applicants must identify any discrete customer groups that may be materially impacted by changes to other rates and charges.

2.4 Exhibit 4: Operating Expenses

This exhibit includes information that summarizes:

1) Gas Supply, Transportation and Storage Costs
2) Lost and Unaccounted for Gas
3) Operating, Maintenance, and Administrative Costs (OM&A)
4) Depreciation expense
5) Taxes
6) Demand Side Management Costs

2.4.1 Gas Supply, Transportation and Storage Costs

The applicant must provide an overview of its gas supply planning process including a discussion of its gas supply planning principles. A gas supply plan must be presented for the bridge year and forward test year showing supply sources, volumes, and a summary of gas transportation contracting arrangements. Expected gas costs should be provided for the bridge and forward test year together with a gas supply/demand balance sheet.

The applicant is required to present a summary of the gas cost consequences of its gas supply plan, including transportation and storage. The applicant must provide a five year historical summary of its volumes, gas costs, supply basin sourcing arrangements, and storage.

Gas supply and related transportation costs are to be updated quarterly under the auspices of the OEB-approved Quarterly Rate Adjustment Mechanism (QRAM) process[4], unless the OEB amends the process during the term.

2.4.2 Lost and Unaccounted for Gas

Applicants must provide five years of historical information relating to actual versus OEB-approved forecasts of lost and unaccounted for gas. Applicants must provide annual forecasts, and an explanation of the methodology underpinning lost and unaccounted for gas forecasting for the bridge and forward test years. Variance explanation of material changes should also be provided.

2.4.3 Operating, Maintenance, and Administrative Costs (OM&A)

OM&A costs should be presented on an output/program-focused basis. Applicants are expected to do a year-over-year variance analysis based on their OM&A programs. In addition, the applicant may also present the information on a departmental basis (i.e. by operating department). This exhibit must include the following sections:

1) OM&A Overview
2) Summary and Cost Driver Tables
3) Program Delivery Costs with Variance Analysis

2.4.3.1 OM&A Overview

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

- OM&A levels for the test year
- Associated cost drivers and significant changes that have occurred relative to historical and bridge years
- Overall trends in costs including OM&A per customer
- Business environment changes
- Cost benchmarking studies (internal and external) or utility cost comparisons conducted by or for the applicant relevant to OM&A
- A description of the continuous improvement or efficiency gains that will be achieved over the term, and the means by which those gains and savings will be achieved, and how the benefits will be realized for customers
- Inflation rate assumed: The utility must provide evidentiary support for the appropriateness of any inflation rate used in forecasting OM&A costs

[4] Amended Decision and Order, *Methodologies for Commodity Pricing, Load Balancing and Cost Allocation for Natural Gas Distributors*, September 21, 2009 (EB-2008-0106)

2.4.3.2 Summary and Cost Driver Tables

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

- Summary of recoverable OM&A expenses
- OM&A cost drivers

Irrespective of the accounting standard used, the applicant must identify the overall change in OM&A expense in the test year that is attributable to a change in capitalized overhead. The applicant must also provide a variance analysis for the change in OM&A expense for the test year in respect to each of the bridge year and the historical years.

2.4.3.3 Program Delivery Costs with Variance Analysis

A program delivery cost refers to OM&A costs that can be grouped and identified by program or major function. The applicant should provide details of costs in the following categories.

1. Workforce planning and employee compensation
2. Shared services and corporate cost allocation
3. Purchase of non-affiliate services
4. One-time costs
5. Low Income programs
6. Charitable and political donations

Workforce Planning and Employee Compensation

The OEB expects that utilities will provide a description of their previous and proposed workforce plans, including compensation strategy. Utilities must discuss the outcomes of previous plans and how those outcomes have impacted their plans including an explanation of the reasons for all material changes to head count and compensation. A complete explanation for all years includes:

- Year over year variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees
- Basis for performance pay, eligible employee groups, goals, measures, and review processes for any pay-for-performance plans
- Relevant studies conducted by or for the applicant (e.g., compensation benchmarking)

Applicants may find Appendix 2-K to the filing requirements for electricity distributors (or any successor document) helpful in structuring this evidence.

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

The applicant must provide details of employee benefit programs, including pensions and other costs charged to OM&A for the last OEB-approved rebasing application, historical, bridge and test years. The most recent actuary report(s) must be included in the pre-filed evidence. The actuary information disclosed in any other area of the application (e.g. tax) must agree with the actuarial analysis.

In May 2015 the OEB initiated a consultation on rate-regulated utility pensions and other post-employment benefits (OPEBs) in the electricity and natural gas sectors[5]. Pending the completion of this consultation, utilities should provide information on the accounting method used by the applicant in the area of pensions and OPEBs as well as a discussion of the differences between the forecast pension and OPEBs amounts proposed for the test year and the amounts forecasted to be paid to the applicable plans or beneficiaries.

Shared Services and Corporate Cost Allocation

Shared services are defined as the concentration of a company's resources performing activities (typically spread across the organization) in order to service affiliates (including a parent company) with the objective of achieving lower costs and higher service levels.

The applicant must identify all shared services between or among its affiliated entities.

Corporate cost allocation is an allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa).

The applicant must provide the allocation methodology, a list of costs and allocators, and any third party review of the corporate cost allocation methodology used. The applicant must provide a self-certification that its costs are in compliance with the OEB's *Affiliate Relationships Code for Gas Utilities*. If the OEB has previously approved the allocation methodology, the relevant docket, date and/or decision granting such approval should be identified.

The applicant must provide details about each service provided or received for the historical (actuals), bridge and test years.

[5] EB-2015-0040

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

- Test year vs. last OEB-approved
- Test year vs. most current actuals

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

Purchase of Non-Affiliate Services

An applicant must provide a copy of its procurement policy, including information in such areas as the level of signing authority, a description of its competitive tendering process and confirmation that its non-affiliate services purchases are in compliance with the policy.

For any material transactions that are not in compliance with the applicant's procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, the applicant must provide an explanation as to why this was the case, as well as the following information for these transactions:

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

One-time Costs

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

Low Income programs

The applicant must provide a description of any low income programs it is administering and identify amounts it is proposing to recover from ratepayers, together with the supporting rationale.

Charitable and Political Donations

The recovery of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to customers in paying their energy bills. Applicants must provide detailed information for all contributions that are claimed for recovery.

The applicant must also confirm that no political contributions have been included for recovery.

2.4.4 Depreciation Expense

The applicant must provide details of depreciation and amortization by asset group for the historical, bridge and test years, including asset amount (breaking out asset additions) and rate of depreciation or amortization. The information must tie to the accumulated depreciation balances in the continuity schedule under rate base.

The applicant must identify any asset retirement obligations (AROs) and any associated depreciation or accretion expenses in relation to the AROs, including the basis and calculation of how these amounts were derived. Any site restoration costs must be disclosed and described.

The applicant must provide a description of the depreciation approach underpinning the depreciation expense calculations in the year a capital asset enters service. The applicant must clearly present the details of its deprecation calculation in regards to the number of months a new capital asset is in service during the year.

The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant must provide a written description of the depreciation practices followed and used in preparing the application. Irrespective of the accounting standard used in the application, the applicant must provide a summary of changes to its depreciation/amortization policy made since the applicant's last revenue requirement filing, or since the OEB last approved a methodology, whichever is most recent. If the applicant has developed a new depreciation study, it must file that study. The applicant must also discuss how the depreciation/amortization expense is calculated under the new depreciation/amortization policy.

The applicant must ensure that the significant parts or components of each plant item are being depreciated separately, in accordance with its adopted accounting standard. Any deviations from this practice must be explained.

2.4.5 Taxes

The applicant must provide the information outlined below:

- Detailed calculations of actual and forecasted regulatory taxable income and income tax, including derivation of adjustments (e.g., tax credits, Capital Cost Allowance adjustments) for the historical, bridge and test years to regulatory taxable income

- Supporting schedules and calculations for reconciling items and adjustments
- A description of the methodology used to calculate income tax
- Copies of most recent Federal and Provincial tax returns (non-utility tax items, if material, must be separated)

Taxes other than income taxes, (e.g. property taxes) should be clearly identified and separately filed.

There may be some expenses incurred by an applicant that are deductible for general tax purposes, but for which regulatory recovery is partially or fully disallowed. Where an expense incurred is non-recoverable in the revenue requirement (e.g. certain charitable donations) or disallowed for regulatory purposes, such amounts should be excluded from the regulatory tax calculation.

2.4.6 Demand Side Management Costs

Natural gas utilities are expected to include detailed information of all approvals for DSM funding from prior proceedings as part of any rate application. Information related to annual budget amounts (including rate class allocation) and the total amount to be recovered through rates to support prior DSM approvals must be clearly described.

2.5 Exhibit 5: Cost of Capital and Capital Structure

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

The OEB issues the cost of capital parameter updates annually. For return on equity (ROE), natural gas utilities should use the most recent parameters for ROE as a placeholder, which will be updated should a new ROE become available prior to the issuance of the OEB's rate order on the application.

The weighted cost of debt should correspond with the debt rates of the utility's actual and forecasted portfolio of debt for the test period, weighted by the principal of each debt instrument.

An applicant may apply for a utility-specific return on equity and/or capital structure. If an applicant wishes to take such an approach, it must provide appropriate justification and expert supporting evidence for its proposal.

2.5.1 Cost of Capital (Return on Equity and Cost of Debt)

The applicant must provide the following information for each year:

- Calculation of the cost for each capital structure component
- Profit or loss on redemption of debt and/or preference shares, if applicable
- Copies of any current promissory notes or other debt arrangements with affiliates
- Explanation of the applicable debt rate for each existing debt instrument, including an explanation on how the debt rate was determined and how each is in compliance with the policies documented in the 2009 Report
- Forecasts of any new debt anticipated in the bridge and test year, including estimates of the applicable rate and any pertinent information on each new debt instrument (e.g. whether the debt is affiliated or with a third party, expected term/maturity, and any capital project(s) directly related to the new debt)

If the applicant is proposing any deviations from OEB policy as documented in the 2009 Report or any successor document, thorough justification must be provided.

2.5.2 Capital Structure

The elements of the capital structure are shown below and must be presented with the appropriate schedules showing current OEB-approved, historical actuals, bridge and test years:

- Long-term debt
- Short-term debt
- Preference shares
- Common equity

Explanations of material changes in actual capital structure are required including:

- Retirements of debt or preference shares and buy-back of common shares
- Short-term debt, long-term debt, preference shares and common share offerings

Any proposal for a change to the deemed capital structure for a natural gas utility from that currently approved by the OEB, must be adequately supported in accordance with the 2009 Report or a successor document. As documented in the 2009 Report, any change in the deemed capital structure would be triggered by a significant change in financial, business or corporate fundamentals.

2.6 Exhibit 6: Revenue Deficiency / Sufficiency

This exhibit should include the following:

- Determination of net utility income
- Statement of rate base
- Actual utility return on rate base
- Indicated rate of return
- Requested rate of return
- Deficiency or sufficiency in revenue
- Gross deficiency or sufficiency in revenues

The applicant must provide a summary of the drivers (including numerical schedules showing the causes) of the test year deficiency/sufficiency, along with the relative contribution of each driver. Specific references to the data contained in the detailed schedules and tables filed in the application must be provided to enable mapping of the summary cost driver information in this exhibit, to the supporting evidence.

Impacts must be provided for any change in methodologies (e.g. accounting standards or policies) on the overall deficiency/sufficiency and on the individual cost drivers contributing to it.

The applicant must isolate delivery-related deficiency/sufficiency separate and apart from the gas supply-related deficiency/sufficiency. Utilities should provide revenue deficiency or sufficiency calculations net of gas supply-related changes captured in the QRAM.

The commodity cost to be used when filing the gas supply-related information will be that available from the most recent OEB-approved QRAM, at the time of filing. The applicant should update the commodity and transportation costs for the most recently approved QRAM for the draft rate order process.

2.7 Exhibit 7: Cost Allocation

In this exhibit, the applicant must provide its proposed cost allocation methodology in the form of a Cost Allocation Study including illustrative step-by-step schedules explaining the approach, and revenue-to-cost ratios. The revenue-to-cost ratios must also include a comparison to the most recent OEB-approved revenue-to-cost ratios and the ratios proposed for the test year.

For any new cost allocation proposals, or changes to an existing methodology, the applicant is required to provide a detailed description of the change, the related financial impact, and the supporting rationale.

The applicant must also include a schedule that compares the allocated customer-related costs per customer per month by rate class (and the cost functions included) to the level of the proposed fixed monthly customer charges[6]. An explanation supporting the level of the proposed fixed monthly cost charges as compared to the allocated customer-related costs must be provided.

The cost allocation evidence must be sufficient to demonstrate that the costs of providing each of the utility services, namely distribution, storage and/or transportation, have been assigned or allocated to assure that there is no undue cross subsidization among customer classes.

2.8 Exhibit 8: Rate Design

The rate design exhibit must provide details of proposed changes to rates, proposed volume and revenue recovery, details regarding changes to proposed rate schedules, and detailed annual bill impacts. Applicants must provide the existing rate schedules and the proposed rate schedules.

The exhibit must include the following:

- Proposed rate and revenue adjustments
- Detailed calculations of revenue per rate class under current rates and proposed rates by customer class
- Detailed reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate blocks, seasons, zones, etc.)
- Calculation of differences between revenue allocated under current rates and proposed rates by customer class
- Explanation and application of non-cost factors to rate design
- Impact of changes on representative samples of end-users, i.e. volume, % rate change, revenue
- Explanation of proposed changes to terms and conditions of service and rationale supporting those changes
- Presentation of miscellaneous service charges including the rationale for any changes relative to OEB-approved and how costing and pricing for any proposed new service charges, and/or changes to rates or rules for existing service charges is determined (utilities must ensure that the revenue from the total of the

[6] Typically the customer-related costs per customer per month by rate class would be determined by dividing the annual costs by 12.

proposed miscellaneous service charges corresponds with the evidence under Operating Revenue)

2.8.1 Bill Impacts

Applicants must provide in summary form, bill impact information in both percentage and absolute dollar terms for all customer classes at the rate class level calculated at typical customer volumes. Applicants should also provide an average bill impact based on volumes at the rate class level.

The utility must file a mitigation plan if the total bill increase for any customer class is material.

The mitigation plan must include the following information:

- Identification of all customer classes or groups of customers that would experience material bill increases
- A description of mitigation measures proposed, e.g. reductions to the revenue requirement, inter-class shifts, or longer disposition periods for deferral and variance account balances
- A justification for all mitigation measures proposed, including reasons if no mitigation is proposed
- Any other information believed to be relevant to the mitigation proposal

2.8.2 Rate Harmonization Plan and Mitigation Issues

Utilities which have merged or amalgamated service areas since their last cost of service or Custom IR application, must file a rate harmonization plan subject to established cost allocation and rate design principles for the natural gas sector. The plan must include a detailed explanation and justification for the implementation plan, and an impact analysis.

In the event that the combined impact of the cost of service based rate increases and harmonization effects result in total bill increases for any customer class that is material, the utility must include a discussion of proposed measures to mitigate any such increases in its mitigation plan discussed in section 2.8.1 above, or provide justification in its plan as to why mitigation is not required.

A migration to fully harmonized rates (where appropriate) that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR term.

2.9 Exhibit 9: Deferral and Variance Accounts

Gas supply and related transportation deferral or variance account balances should continue to be filed for review and disposition quarterly consistent with the OEB-approved QRAM process.

Natural gas utilities are expected to file for review and disposition of all remaining deferral and variance account balances at the time of a cost of service application. This includes any earnings sharing mechanisms, DSM-related deferral and variance accounts (including lost revenues, performance incentives, cost-efficiency incentives and additional DSM expenditures) or other unique accounts that may be part of an approved Price Cap IR plan. All account balances proposed for disposition must be supported by audited balances.

The information outlined below is required whether or not the applicant is seeking disposition of any deferral and variance accounts:

- List of all outstanding deferral and variance accounts including a description of the account
- Confirmation that the interest rates established by the OEB were used to calculate the carrying charges for each deferral and variance account where carrying charges apply
- Listing of accounts to be discontinued and the reasons
- A statement as to whether or not the applicant has made any adjustments to deferral and variance account balances that were previously approved by the OEB on a final basis. If this is the case, the applicant must provide an explanation of the nature and amount of any adjustment and include supporting documentation; under a section titled “Adjustments to Deferral and Variance Accounts”.

2.9.1 Disposition of Deferral and Variance Accounts

The applicant must:

- Identify all accounts for which it is seeking disposition
- Identify any accounts for which the applicant is not proposing disposition and the reasons
- Propose the methodology and rationale for the recovery, or refund, of balances including the allocation methodology used, timing and duration of any rate riders, rate class impacts, and typical customer bill impacts
- Provide a statement as to whether the balances proposed for disposition are consistent with the account balances reported in the RRR and the relevant year’s audited financial statements and if not, provide explanations for variances

For each account requested for disposition, the applicant should provide a continuity schedule for the period commencing from the establishment of the account or from the last approved disposition of the account, whichever is more recent, to the date of the most recent audited actuals. The continuity schedule is to show separate itemization of opening balances, annual adjustments, transactions broken down into appropriate categories, interest and closing balances. The applicant must file this schedule in Excel format.

2.9.2 Establishment of New Deferral and Variance Accounts

In the event an applicant seeks an accounting order to establish a new deferral or variance account, the request must be accompanied by evidence of how the following eligibility criteria will be met:

- Causation – The forecasted expense must be clearly outside of the base upon which rates were derived

- Materiality – The forecasted amounts must exceed the OEB-defined materiality threshold and have a significant influence on the operation of the distributor, otherwise they must be expensed in the normal course and addressed through organizational productivity improvements

- Prudence – The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers

The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement. The default materiality thresholds for the establishment of new accounts are as follows:

- $50,000 for a utility with a revenue requirement less than or equal to $10 million
- 0.5% of revenue requirement for a utility with a revenue requirement greater than $10 million and less than or equal to $200 million
- $1 million for a utility with a revenue requirement of more than $200 million

In addition, applicants must include a draft accounting order that contains a description of the new account and its mechanics, the proposed general ledger entries, and the manner and timing proposed for disposition.

2.9.3 Z-Factor

Natural Gas utilities may propose a Z-factor mechanism as part of its application to address material cost increases or decreases associated with unforeseen events outside of the control of management for the incentive rate-setting term. The cause of the increase or decrease must be reasonably outside the control of utility management and must be a cause that utility management could not reasonably control or prevent through the exercise of due diligence.

To date, the OEB has approved utility-specific criteria and materiality thresholds for Enbridge Gas Distribution Inc., Union Gas Limited and Natural Gas Resource Ltd. in previous proceedings. Both the approved criteria and thresholds have differed and in some cases, such as for materiality thresholds, have differed substantially from each other and from the thresholds used in the electricity sector[7].

The Rate Handbook notes that 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.[8]

An applicant filing under the Price Cap IR method may follow this same approach in a cost of service application under these filing requirements. In the absence of a proposal for an alternative mechanism, the current materiality thresholds for each utility will continue to apply.

In either case, an applicant seeking Z-factor relief must include in its proposal a calculation of its regulated return from its most recent complete audited year. If the regulated return exceeds the deemed return on equity embedded in the utility's rates, an applicant must justify why the relief sought is reasonable.

Any Z factor proposal must address the four criteria of causation, materiality, prudence and management control. The definitions outlined below are based on those approved for Enbridge Gas Distribution Inc. with modifications to the causation criteria to make clear that any cost increase or decrease must not only be related to an unexpected, non-routine event but also must be outside of the base on which rates are derived.

[7] Current materiality threshold for Union is $4M on revenue requirement, for Enbridge is $1.5M on revenue requirement, for NRG is $50K event cost (i.e. this number is not specified as a revenue requirement number consistent with the electricity sector for utilities with revenue requirements of less than $10M), for Hydro One Transmission is a minimum threshold of $3M event cost, and for Hydro One Distribution is $1M event cost (i.e. both of these latter numbers are also not specified as revenue requirement numbers).

[8] Rate Handbook, pg. 27

- Causation – The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event and must be clearly outside of the base upon which rates were derived

- Materiality –The cost increase or decrease must meet a materiality threshold, in that its effect on the utility's revenue requirement in a fiscal year must be equal to or greater than the established threshold

- Prudence – The cost subject to an increase or decrease must have been prudently incurred

- Management Control - The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management could not reasonably control or prevent through the exercise of due diligence

The materiality threshold must be met on an individual event basis in order for the utility to apply for recovery of the relevant costs.

Consistent with the Z-factor policy applicable to electricity distributors and transmitters, if an applicant proposes a Z factor claim, the applicant must:

- Notify the OEB promptly of all Z-factor events. Failure to notify the OEB within six months of the event may result in disallowance of the claim.
- Record costs for which recovery will be sought
- At the time of the disposition review, outline the manner in which it intends to allocate the Z-factor award to the various rate classes, the proposed disposition period, the rationale for the selected approach and a discussion of the merits of alternative allocation methods
- At the time of the disposition review, provide a detailed calculation of the incremental revenue requirement

2.10 Exhibit 10: Incentive Rate-setting Proposal

This exhibit must include details of the components proposed for the Price Cap IR method including the basis for the inflation, productivity and stretch factors, customer protection measures, any capital factor proposed for the incentive rate-setting period, and any other elements that may be included in the proposal. Utilities must also file their plan for any annual applications that may make up part of their proposal for the incentive rate-setting period.

Traditionally, natural gas utilities have proposed Y-factors (both capital and non-capital) for incentive rate-setting years (i.e. non-rebasing years). Y-factors are a cost recovery mechanism for costs that are incremental to the test period and are incurred during the IR period. They have covered a variety of costs such as:

- Costs approved in other proceedings and implemented as part of the main annual rates application such as DSM program costs
- Costs that are strict pass-through items (i.e. no mark-up) such as upstream gas supply costs (commodity and transportation)
- Incremental utility costs and revenue variances (i.e. non-pass through items) such as DSM-related and other volume variances, and the revenue requirement impact of capital projects approved in leave to construct proceedings.

Going forward, the OEB expects that the practice of implementing prior approved costs will continue as part of the annual rate application during the incentive rate-setting period (e.g. DSM budgets and cap-and-trade costs, etc.). Likewise, natural gas utilities are expected to continue to propose upstream gas cost updates during the incentive rate setting period in accordance with the QRAM process. These two sets of adjustments are generally not unique to a utility-specific rate-setting plan and should therefore not be labelled together with other plan-specific modules or adjustments.

Consistent with the Rate Handbook requirement for a Custom IR filing, if a utility proposes an earnings sharing mechanism (ESM) as part of a Price Cap IR plan as its mechanism to protect customers against excess earnings, it should generally be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term. An applicant may propose a threshold to trigger the disposition of a significant ESM balance during the IR plan term.