

KPMG Report to the Ontario Energy Board

Report on Pension and Other Post-Employment Benefit Costs

May 2, 2016



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May 2, 2016

Dear Mr. Antonopoulos

Re: KPMG Report on Pension and Other Post-Employment Benefit Costs

In accordance with our engagement letter dated April 23, 2015 and Ontario Energy Board's Purchase Order PO-001829 dated April 24, 2015, please find attached our report on Pension and Other Post-Employment Benefit Costs.

It has been a pleasure working with the Ontario Energy Board on this engagement and we look forward to presenting our report at the proposed Consultation.

Yours truly

KPMG LLP

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Preface and Disclaimer

Benefits provided to employees in consideration or exchange for service rendered to a utility take many different forms (including salaries and wages, compensated absences, disability benefits, bonuses and incentive pay and post-employment benefits). Of these different forms of benefits, Pension and Other Post-Employment Benefit (“P&OPEB”) costs have been receiving much attention in Canada, particularly in Ontario. Issues relating to P&OPEB costs are complicated by the fact that the benefits are promised during the course of employment but the benefits are only payable after the completion of employment (i.e. post-employment benefits); often, this can be several decades after the date when service by an employee leads to benefits under the arrangement. This can have a profound impact on issues such as the nature of the benefits that are promised, who pays for and/or bears the risks associated with the benefits that have been promised, how the cost of providing those benefits is allocated to each period in a rational and equitable manner, etc.

This report does not seek to address all these issues. Rather, the Ontario Energy Board (“OEB”) is beginning a consultation on rate-regulated utility P&OPEB costs in the electricity and natural gas sectors (“the Consultation”). The objectives of the Consultation are to develop standard principles to guide the OEB’s review of P&OPEB costs in the future, to establish specific information requirements for applications that may be incremental to current filing requirements, and to determine whether appropriate regulatory mechanisms for recovery of P&OPEB costs can be developed and applied consistently across the gas and electricity sectors for rate-regulated utilities. KPMG LLP (“KPMG” or “we”) has been retained by the OEB to provide assistance to the OEB on the issues identified in this report. KPMG is not advocating positions in this report. Rather, we have attempted to identify issues that we think are relevant to focus and inform the discussions that will take place during the Consultation. We have also responded to and provided guidance and insight on specific technical accounting issues which are of interest to the OEB. However, in order to derive the greatest value, users of this report should also acknowledge the following issues which are important to the discussion:

1. KPMG understands that the OEB is not seeking to make drastic changes to the way it sets rates as part of this review but rather to develop principles and requirements for P&OPEB costs based on established rate-making principles such as intergenerational equity, rate stability and predictability as well as statutory objectives such as financial viability of the electricity and gas industry. There may be new regulatory filing and reporting requirements for P&OPEB costs. It is also important to recognize that the OEB considers many factors in setting rates. Therefore, in some cases, implementation of new principles and requirements may have varying impact on the existing practices of different utilities;
2. The goal of achieving greater consistency should not over-ride the OEB’s statutory mandate to set ‘just and reasonable’ rates. In certain cases, a “one-size fits all” approach is simply not

desirable or justifiable. For this reason, the principles and requirements should offer flexibility in some areas;

3. Benefits offered through P&OPEB plans are a form of deferred compensation and, often, these benefits are an integral part of the overall compensation that is provided to employees. As such, P&OPEB costs should not be viewed in isolation;
4. This report identifies certain differences during a specified reporting period between the P&OPEB costs recorded under accrual accounting and their cash (or funding) cost. The differences can be significant because the P&OPEB costs are defined by different frameworks which have specific and separate methodologies for setting assumptions and calculating costs. Indeed, there is no guarantee that one method will *always* result in higher (or lower) costs for a given period than the other. Further, the accrual accounting cost method has differences that relate to different accounting requirements in the various accounting frameworks currently available for use in Canada. That said, despite these periodic differences in P&OPEB costs, in the fullness of time, the cumulative cash (or funding) costs for a plan (or arrangement) is generally expected to equal that plan's cumulative accrual accounting costs. This is true regardless of the accounting framework that is used by a regulated utility. As such, over time, a regulated utility would recover all its P&OPEB costs irrespective of the method that is used to include these costs in rates. However, if the OEB were to move all the regulated utilities to a common regulatory mechanism for including P&OPEB costs in rates, it will be important to determine how, in the fullness of time, those regulated utilities that would have had to change their mechanism for recovering the costs are impacted in their ability to eventually recover their prudently incurred costs through rates charged to customers;
5. Due to the fact that revenue collected from customers to pay for P&OPEB costs may, in certain instances, only be paid out by the regulated entity well into the future, an issue arises whether customers are getting an appropriate return or 'value-for-money' on the money that is held by the regulated entity during the intervening period. The results of such 'value-for-money' assessments would obviously depend on a number of factors, including how the regulated utility has used or invested the money that it would have collected in advance of the P&OPEB payments. While KPMG has identified various options with 'value-for-money' in mind, the results of any 'value-for-money' analyses would vary from utility to utility; as such, detailed, quantitative 'value-for-money' assessments are outside the scope of this report;
6. The scope of the accounting guidance included in this report is limited, and is intended to only address the specific issues that have been identified by OEB staff. As such, the accounting guidance does not address all issues relating to P&OPEB costs neither is it intended to address in detail all the accounting requirements under the various accounting frameworks. Such detail can only be obtained from a complete read of all the accounting pronouncements and interpretations issued by the relevant authoritative accounting bodies; and

7. We have prepared for consideration methods for recovering P&OPEB costs and related Information Requirements that, if adopted, should lead to greater consistency in the regulatory treatment of P&OPEB costs that are included in rates. KPMG is not responsible for determining which, if any, of these methods for recovering P&OPEB costs and related Information Requirements get adopted by the OEB. It is also possible to have variations to these methods and Information Requirements or a different combination of individual methods and Information Requirements.

Disclaimer

This report has been prepared and is intended solely for the OEB and OEB staff. It is our understanding that the OEB may conduct a public consultation on the issues that have been identified in this report; in which case, this report may be made available for ‘information only’ to the participants of that public consultation. The report may not be edited or relied upon by any other person without the express written permission by KPMG, which permission will not be unreasonably withheld.

The accounting guidance contained in this report is general in nature and is not intended to apply to every fact pattern. Like other issues relating to reporting in general purpose financial statements, it is possible to make different judgments based on specific facts and circumstances and materiality of the amounts involved.

The accounting guidance contained in this report also does not deal with any specific fact pattern or rate proceeding that is currently before the OEB. However, the accounting guidance may inform and influence the OEB’s approach to P&OPEB costs in the future. The OEB (not KPMG) determines how the issues identified in this report are dealt with for purposes of setting rates and related regulatory reporting. However, any and all decisions regarding how the issues identified in this report are addressed in a regulated entity’s general purpose financial statements are made by the regulated entity’s management, and auditors opine on those financial statements.

Accounting pronouncements and interpretations are subject to revision by the relevant authoritative accounting bodies. The accounting guidance is based on our understanding of pronouncements and interpretations at the date of this report. As such, the accounting guidance may change materially in response to subsequent changes or, revisions to, the pronouncements and/or interpretations. KPMG assumes no responsibility to update the accounting guidance.

KPMG will not assume responsibility or liability for damages or losses suffered by anyone as a result of circulation, publication, reproduction, or use of this report contrary to the provisions of this disclaimer. The information contained in this report is based solely on the purpose and scope of work set out herein, and is subject to the limitations set out in Section 1.3 of this report.

Acknowledgements

KPMG wishes to acknowledge the assistance of others in the preparation of this report. In particular, the survey participants in Canada and internationally were most helpful in ensuring a full understanding of their regulatory practices with regard to P&OPEB costs, and we thank them.

KPMG benefitted particularly from the generosity of William McKenzie, Senior Manager Technical Accounting Regulatory Finance, Smarter Grids & Governance, of the Office of Gas and Electricity Markets (“Ofgem”), the regulator for Great Britain based in London, England. He responded to several follow up calls as the team evolved its understanding of the Ofgem framework and the particulars of the regulatory regime in Great Britain.

Staff of the Financial Services Commission of Ontario also assisted in providing understanding of their oversight role with regard to pension plans in Ontario and staff at OMERS, through OEB staff, provided insight into utility participation in the OMERS pension plan.

Lastly, the staff of the Ontario Energy Board contributed to the development of this report, particularly with regards to the understanding of regulatory principles and the rate regulatory regime in Ontario. KPMG thanks them all for their assistance.

This report reflects the results of significant collaboration and teamwork and KPMG gratefully acknowledges the contributions of all participants.

Executive Summary

The OEB engaged KPMG to identify methods of recovering P&OPEB costs and develop associated Information Requirements for potential adoption by the OEB as a framework for addressing the rate-regulatory treatment of P&OPEB costs for the electricity and gas utilities in Ontario and for use when reviewing rate applications.

This report does not address specific criteria that can be used to assess the reasonableness of P&OPEB costs in rate applications. The report outlines certain information requirements that may be considered during the Consultation as a starting point for discussion on how to approach the assessment of P&OPEB costs. The bulk of the report focuses on alternatives for cost recovery mechanisms. This report also includes a jurisdictional review on the treatment of P&OPEB costs. A key finding of that review is that none of the regulators surveyed reported that their regulatory practice for the treatment of P&OPEB costs is based solely on the application of the requirements of accounting standards.

Methods for Recovering P&OPEB Costs and Information Requirements

This report summarizes KPMG's work and identifies methods of recovering P&OPEB costs as well as a set of Information Requirements for consideration by the OEB. The methods of recovering pension costs and related Information Requirements are set out in Section 2 of this report. Methods of recovering OPEB costs and related Information Requirements are set out in Section 3 of this report.

There are two primary methods that have been used by regulated utilities in Ontario to recover P&OPEB costs in the rates charged to customers – legislated funding contribution (for registered pension plans only) and/or accrual accounting costs (for registered and unregistered pension plans and OPEB plans). A third method, 'pay-as-you-go' cash payments, is currently only used by a few regulated utilities in Ontario.

We have identified an additional method for pensions that is an alternative to the above-mentioned legislated funding contribution method, i.e. the "Modified Funding Contribution method". The Modified Funding Contribution amount represents the minimum amount of contributions required to be made by a sponsor of a registered pension plan that is subject to the requirements of pension legislation under the Pension Benefits Act, Ontario ("PBA"), modified by the fact that only an employer's normal cost contribution and going concern special payments using the 15-year amortization period are included in the current period's rates. Any other special payments required under the PBA and other additional payments beyond the minimum funding contributions required by the PBA that an employer chooses to make would be recorded in separate deferral accounts, and be recovered in the rates in a future period as determined by the OEB. The overall result is that the amount calculated under the Modified Funding Contribution method would be less volatile than the amount calculated using the (traditional) funding contribution method that is described above.

For OPEB costs, we have also identified an additional method that is an alternative to the, ‘pay-as-you-go’ cash payments method, i.e. the adjusted ‘pay-as-you-go’ cash payments method. Under this method, ‘pay-as-you-go’ cash payments are the starting point (foundation) for determining the amount that is included in rates. However, such ‘pay-as-you-go’ cash payments are increased by an additional amount that is established by the OEB.

We have also identified Information Requirements that would support the regulatory review of P&OPEB costs. In some instances, the Information Requirements represent codification of existing requirements that have not been previously codified as part of the OEB’s regulatory requirements. However, in other instances, the Information Requirements do result in new regulatory filing and reporting requirements. The impact may be significant; details of the extent of the changes and impact of those changes can only be determined on a case by case basis.

The proposed public consultation may wish to consider the methods for recovering P&OPEB costs that have been identified in this report as well as some, or all, of the accompanying Information Requirements. If the OEB were to adopt the methods for recovering P&OPEB costs and the Information Requirements identified in this report, this would have the following impact on regulated entities:

- **Pension plans accounted for as DC plans:** No change to existing regulatory treatments. This includes costs with respect to multi-employer pension plans such as OMERS which are defined benefit plans but are accounted for by participating employers as DC plans.
- **Registered pension plans accounted for as DB plans:** The OEB may wish to consider changing the method of recovering these costs to the Modified Funding Contribution method. Any special payments or other additional payments not included in that period’s rates (i.e. “excess payment”) would be included in deferral accounts pending the OEB’s decision on disposition of the amount and would attract an appropriate return.

There are a number of reasons that suggest using the funding contribution rules as opposed to the accounting rules: transparency and greater objectivity in setting assumptions, the fact that it is easier for stakeholders to understand the inclusion in rates of ‘cash costs’ and, as the amounts included in rates do not depend on the accounting framework that is adopted by a utility, greater consistency and comparability between regulated entities and thus more equitable treatment of customers, and the avoidance of excess/(under) recovery of cash which can occur when accrual accounting costs are included in rates. By modifying the amount that is included in the current period’s rates to comprise only an employer’s normal cost contribution and going concern special payments using the 15-year amortization period, this would significantly reduce the volatility of amounts determined using the funding contribution rules of the PBA. On the other hand, the OEB would retain flexibility regarding the timing and period of recovery of any amounts that are paid by a utility in excess of the Modified Funding Contributions. *[Adopting this method for recovering pension costs will result in change for some large electricity and gas utilities in Ontario that previously used the accrual accounting cost for DB plans in setting rates]*

Non-registered P&OPEB plans: No change to existing regulatory treatment for non-registered pension plans and OPEB plans if the accrual accounting cost method is adopted. However, if the accounting framework that is used by a utility does not periodically reclassify to net income the component of P&OPEB costs that is recorded in OCI, a utility would be required to record that amount in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the plan. Further, if cost recoveries are based on accrual accounting cost, the considerations for a set-aside mechanism that is discussed further below would be relevant to any P&OPEB costs that are recovered using this method.

On the other hand, if the adjusted ‘pay-as-you-go’ cash payments method is adopted for non-registered P&OPEB plans, this would represent a significant change for most regulated utilities.

[Adopting these methods for recovering P&OPEB costs for non-registered plans will result in significant change for the industry]

- **All P&OPEB plans:** The identified Information Requirements introduce increased regulatory filing requirements for P&OPEB costs in rate applications and additional reporting requirements for ongoing monitoring by the OEB.

Details of the extent of the impact of the changes vary from utility-to-utility and can only be determined on a case-by-case basis.

Accounting guidance for P&OPEB costs based on ASC 980 (US GAAP)

US GAAP includes special accounting provisions that are applicable to entities with activities that are subject to rate regulation. The result is that regulated entities are required to recognize regulatory assets and liabilities provided certain specified criteria are met. This analysis was conducted in order to assess the impact of deferring costs for rate-making purposes (under the methods discussed in this report) on utilities currently under US GAAP. This analysis is also informative for utilities that elected to apply the regulatory accounting guidance that was recently introduced under IFRS as IFRS looks to the US GAAP standard for guidance on this matter¹.

In order to capitalize an incurred cost (including amounts recognized in Other Comprehensive Income) as a regulatory asset, a regulated entity is required to assess whether it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. Determining whether it is probable that incurred costs will eventually be included in rates is often the most difficult part of applying the accounting requirements for regulatory assets. Actions by the regulator can greatly influence the recognition of regulatory assets.

The level of judgment involved is much more significant for P&OPEB costs as the period of recovering these costs from customers can extend well into the future. As such, subject to it being

¹ Refer to Section 2.4 of this report for details.

probable that the costs will be included in future rates, US GAAP has the following specific requirements for P&OPEB costs:

- a) *Pension costs*: as detailed in Section 2.4.2 of this report, regulatory assets and liabilities are generally recognized. US GAAP does not specify any time limits for the recovery of the pension costs in future rates; and
- b) *OPEB costs*: US GAAP explicitly prohibits the recognition of regulatory assets when OPEB costs are recovered on a ‘pay-as-you-go’ basis. For those OPEB costs that are not recovered in rates on a ‘pay-as-you-go’ basis, and subject to certain specified criteria being met (see details in Section 3.5.2 of this report), regulatory assets and liabilities are generally recognized. As such, regulatory assets may be recognized for OPEB costs as long as the method of recovery is not ‘pay-as-you-go’ and the other specified criteria are met. There is no requirement under US GAAP for OPEB costs to be recovered in rates on the accrual accounting cost method; however, in order for the resulting regulatory assets to be recognized in general purpose financial statements, the method of cost recovery cannot be the ‘pay-as-you-go’ method.

Section 2.4.5 and Section 3.5.5 of this report identify actions that the OEB could take to influence the recognition of regulatory assets for P&OPEB costs. These actions could provide additional clarity to the regulatory treatment of P&OPEB costs in ratemaking and could help to reduce diversity in practice by the entities that are regulated by the OEB as well as their auditors.

It is important to note that regulated entities that prepare their general purpose financial statements in accordance with legacy Canadian GAAP and ASPE, as well as those regulated entities that are eligible to elect to apply the requirements of IFRS 14 and elected to do so when they adopted IFRS, generally all recognize regulatory deferral and variance accounts in accordance with the US GAAP accounting principles identified above. As such, in most instances, the above accounting requirements are equally applicable to the regulated entities that report under these three accounting frameworks.

Alternatives for possible set-aside mechanisms

To date, the OEB has allowed the majority of regulated utilities to include accrual accounting costs for pension and/or OPEB plans in rates. The P&OPEB costs determined by accrual accounting can be significantly different to the cash payments actually made by the regulated utility under the plan. In some cases, particularly with regards to unregistered P&OPEB plans, revenue can be collected from customers well in advance of the payments being made for the benefit obligations.

This report explores ways that customers can be provided with ‘value-for-money’ on the cash that is collected in advance of cash payments being made on OPEB obligations (i.e. excess recoveries), while at the same time safeguarding customers’ money that will be directed to settling the obligations in the future. If the OEB were to decide that accrual accounting cost is used to include P&OPEB costs in rates, alternatives for possible set-aside mechanisms could also be developed in

order to achieve this objective. Consideration should be given to the following alternatives for possible set-aside mechanisms:

- a) Internally segregated accounts;
- b) Retirement compensation arrangements;
- c) Excess recoveries reduce rate-base; or
- d) Continuing with the current practice, but recording any excess recoveries in separate regulatory accounts that would attract interest as specified by the OEB.

Details of these alternatives, as well as their pros and cons, are discussed in more detail in Section 3.4.2 of this report.

1. Introduction

1.1 Purpose and scope of this report

The Ontario Energy Board (“OEB” or “Board”)¹ is beginning a consultation on rate-regulated utility pensions and other post-employment benefits (“P&OPEB”) in the electricity and natural gas sectors (“the Consultation”). Historically, the OEB has addressed P&OPEB issues on a case-by-case basis. The objectives of the Consultation are to:

1. Develop standard principles to guide the OEB’s review of P&OPEB costs in the future;
2. Establish specific information requirements for applications that will be incremental to current filing requirements; and
3. Determine whether appropriate regulatory mechanisms for cost recovery can be developed and applied consistently across the gas and electricity sector for rate-regulated entities.

The OEB has retained KPMG LLP (“KPMG”) to provide assistance to the OEB on technical issues with respect to P&OPEBs. This report has been prepared to respond to and specifically address the following assistance that has been requested of us by the OEB:

1. Review the regulatory practices for recovering P&OPEB costs by rate-regulating boards and commissions in other jurisdictions as identified and agreed to with OEB staff;
2. Identify methods of recovering P&OPEB costs and related Information Requirements that could be used to develop a proposed common principle-based framework relating to the regulatory treatment of P&OPEB costs by the OEB. The OEB would like to adopt a set of principles and requirements that will be used to address the regulatory treatment of P&OPEB costs in a consistent manner. It is important to note that the OEB already applies established rate-making principles such as intergenerational equity, rate stability and predictability in setting rates. In addition, the manner in which it sets rates has to comply with statutory objectives such as financial viability of the electricity and gas industry. KPMG understands that the OEB is not seeking to make changes to these overarching principles and objectives and will continue to abide by them. However, the OEB is seeking to develop incremental principles and requirements that would lead to greater consistency in the regulatory treatment of P&OPEB costs specifically.

In order to begin the Consultation process, the OEB developed a list of questions which were designed to elicit initial views from stakeholders on some of the key issues of interest to the

¹ Acronyms are listed in Appendix L and identified when they are first used in this report.

OEB. KPMG has read the initial written submissions that were received by the OEB, and the methods of recovering P&OPEB costs and Information Requirements that are set out in this report were informed by these written submissions. However, it is important to note that although methods of recovering P&OPEB costs and related Information Requirements have been identified in this report, KPMG is not advocating positions – this can only be done effectively as part of the Consultation process. As requested by the OEB, we have attempted to identify practices that would lead to greater consistency in the regulatory treatment of P&OPEB costs that are included in rates. In some instances, the Information Requirements include documentation of current OEB practices for P&OPEB costs;

3. Identify the accounting requirements for P&OPEB costs in general purpose financial statements of regulated electricity and gas utilities in Ontario. Specifically, the OEB requested KPMG to provide guidance on accounting for P&OPEB costs under the United States generally accepted accounting principles (“US GAAP”), International Financial Reporting Standards (“IFRS”) and Accounting Standards for Private Enterprises (“ASPE”);

The OEB also requested KPMG to provide specific guidance on the accounting requirements for P&OPEB costs for regulated utilities that prepare their general purpose financial statements in accordance with US GAAP. The OEB wanted to understand whether regulatory assets could be recognized for differences between the cash basis for ratemaking purposes and accrual accounting. The guidance was to also identify opportunities in which the decision or actions of a regulator would influence whether the regulatory assets can be recognized in general purpose financial statements and, if there are circumstances in which the regulatory assets could be recognized, provide guidance on the maximum time period permitted under US GAAP for recovering any such recognized regulatory assets; and

4. Finally, the OEB requested KPMG identify alternatives for possible set-aside mechanisms that could be developed if accrual accounting is used to recover P&OPEBs costs in rates. We understand that the purpose of the set-aside mechanism would be to provide customers with ‘value-for-money’ on the revenue that is collected in advance of cash payments being made on the P&OPEB obligations (i.e. excess recoveries), while at the same time safeguarding customers’ money that will be directed to settling the P&OPEB obligations in the future.

1.2 Overview of P&OPEB Costs Incurred by Regulated Utilities in Ontario

In Ontario, the majority of the regulated utilities are members of the Ontario Municipal Employees’ Retirement System (“OMERS”). OMERS provides pensioners with a defined benefit upon retirement and is thus a DB plan. However, because it is a multi-employer plan that is currently

unable to identify the amount of invested funds that are attributable to an individual participating employer or the amount of specifically associated obligations, accounting rules require participating employers to recognize the amount of contributions to the OMERS pension fund as the pension cost for that financial reporting period. It is thus accounted for in the same way as a DC plan while in actual fact it is a DB plan.

The large utilities that are not members of OMERS are Hydro One (distribution and transmission), Ontario Power Generation, Union Gas and Enbridge Gas Distribution. The large utilities and the Independent Electricity System Operator (“IESO”) that are not members of OMERS record their DB plans in their general purpose financial statements in accordance with the applicable accounting framework. The following table illustrates the funding position at December 31, 2014 and related P&OPEB costs for the four large regulated utilities in Ontario and IESO:

(in millions)	Hydro One		OPG		Union Gas		Enbridge		IESO	
	Pension	OPEB	Pension	OPEB	Pension	OPEB	Pension	OPEB	Pension	OPEB
Assets	6,299	0	12,407	0	829	0	960	13	455	0
Liabilities	7,535	1,582	15,986	3,143	863	67	1,046	117	452	69
Funded status (deficit)	(1,236)	(1,582)	(3,579)	(3,143)	(34)	(67)	(86)	(104)	3	(69)
Net periodic costs	158	134	554	202	20	4	25	6	14	8
Charge to P/L	81	62	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Amortization period of OCI (years)	11	12	12	13	10	n.a.	n.a.	n.a.	13	14

n.a - Detail of the charge to the P/L is not disclosed in the financial statements. In most cases, some of the net periodic cost is capitalized to property, plant and equipment.

Source: 2014 annual financial statements.

As mentioned in Appendix H, although the last couple of years have seen improved equity-market performance, the impact of the improved market performance on the overall funded status of most pension plans in Canada has been largely offset by the effect of the historically low interest rate environment on the present value of plan obligations.

1.3 Limitations of this Report

This report should only be used for the purpose set out above. This report is also subject to the following limitations:

1. The focus of this report is solely on P&OPEB costs. We recognize that benefits offered through P&OPEB plans are a form of deferred compensation and, often, these benefits are an integral part of the overall compensation provided to employees. As such, an analysis of P&OPEB costs can only be complete and effective if it is not done in isolation of the other compensation that is provided to employees;
2. As the scope of the engagement did not include discussions with regulated utilities, it is very difficult, and in some cases impossible, to anticipate and quantify the impact of the methods of recovering OPEB costs and related Information Requirements on regulated utilities. Where possible, we have used regulatory and financial information that is publicly available. However, such an impact assessment should be viewed as only providing initial high-level directional guidance and is subject to change;
3. The Information Requirements propose new regulatory filing and reporting requirements for P&OPEB costs in rate applications. This report does not seek to identify the potential reaction, response or regulatory action by the OEB and/or other stakeholders to the information that will be reported by the utilities. It is simply too early and would be speculative to attempt to do so;
4. Certain statements made in this report are based on what has happened or existed in the past (e.g., statements such as ‘pension plans have significant deficits’ or ‘costs are increasing’). It is important to note that a significant part of P&OPEB costs are dependent on market conditions at a specific point in time (this includes variables such as discount rates, the market performance of plan assets, etc.), and these market conditions are not controlled by the regulated utilities. There can be no assurance that what has happened in the past will repeat itself in the future. As such, it is possible that the results in future periods may be different. Appendix H illustrates, by way of example, some of the recent publicity regarding the funded status of pension plans in Canada;
5. We have identified the methods of recovering P&OPEB costs and related Information Requirements that we think would, if adopted, help to lead to greater consistency in the regulatory treatment of P&OPEB costs that are included in rates. It is possible to have variations to these methods of recovering P&OPEB costs and related Information Requirements or a different combination of individual methods of recovery and Information Requirements. Ultimately, however, the decision on which of the methods or recovering P&OPEB costs and related Information Requirements get adopted is that of the OEB; and

6. We recognize that not all situations fit into a uniform policy framework. As with any policy, the OEB will need to take into account all the facts and circumstances, including materiality to the regulated entity and overall impact to the rates that it charges customers, to determine the applicability of the policy position to particular cases.

1.4 Report Outline

The remainder of the report is organized as follows:

- **Section 2, “Methods Identified for Recovering Pension Costs and Related Information Requirements”** presents the methods that we have identified for recovering pension costs as well as the associated Information Requirements. This Section of the report comprises the following subsections:
 1. The methods identified for recovering pension costs;
 2. Rationale for the methods identified for recovering pension costs – this describes the rationale for various alternatives considered by KPMG in framing the identified methods for recovering costs relating to pension plans. The subsection also includes a summary of the results of KPMG’s work in gathering inputs relevant to identifying the appropriate methods of recovering pension costs and related Information Requirements – a so-called “environmental scan”. This included a review of P&OPEB practices of rate-regulators in other jurisdictions, a review of the role of other regulatory authorities in Ontario with respect to P&OPEB matters, and the results of other relevant research;
 3. Accounting guidance for pension costs based on ASC 980 (US GAAP) – this details the special accounting provisions that are applicable to pension costs for those entities with activities that are subject to rate regulation and prepare their general purpose financial statements under US GAAP; and
 4. Information Requirements identified for pension costs.
- **Section 3, “Methods for Recovering OPEB Costs and Related Information Requirements”** presents the methods that we have identified for recovering OPEB costs as well as the associated Information Requirements. This Section of the report comprises the following subsections:
 1. The method identified for recovering OPEB costs;
 2. Rationale for the method identified for recovering OPEB costs – this describes the rationale for various alternatives considered by KPMG in framing the identified method for recovering costs relating to OPEB plans;
 3. Alternatives for possible set-aside mechanisms – this identifies possible set-aside mechanisms that could be developed in order to provide customers with ‘value-for-money’ on the cash that is collected in advance of cash disbursements being made on the OPEB obligations (i.e. excess recoveries). This subsection is only relevant if accrual accounting

cost is used to recover OPEB costs in rates, and would also be equally applicable if accrual accounting cost is used to recover pension costs in rates;

4. Accounting guidance for OPEB costs based on ASC 980 (US GAAP) – this details the special accounting provisions that are applicable to OPEB costs for those entities with activities that are subject to rate regulation and prepare their general purpose financial statements under US GAAP; and
 5. Information Requirements identified for costs relating to OPEB plans.
- **Appendices** to this report set out various areas that form the background to the methods for recovering P&OPEB costs and related Information Requirements that have been identified. These include more detail on the regulatory oversight environment for P&OPEB Plans in Ontario, the accounting requirements under different accounting frameworks, illustrative examples of accounting practices by Canadian regulated entities that report under US GAAP, more detailed explanations of the results of the review of P&OPEB regulatory practices in other jurisdictions and examples of additional guidance issued by other regulators, information regarding recent trends in the pension environment, and a glossary of definitions and acronyms used in this report.

Accounting and regulatory requirements for P&OPEB costs are complex. Users of this report that do not have a detailed understanding of the accounting and regulatory requirements for P&OPEB costs are strongly encouraged to first read the appendices to this report before reading the detailed discussions in Section 2 and Section 3 of this report.

2. Methods Identified for Recovering Pension Costs and Information Requirements

2.1 Overview of Section

This Section presents proposed methods for recovering pension costs and related Information Requirements. Specifically:

- **Section 2.2** sets out the methods identified for recovering pension costs;
- **Section 2.3** provides the rationale for the methods identified for recovering pension costs. This Section also includes a summary of the results of KPMG’s work in gathering inputs relevant to identifying the appropriate methods for recovering pension costs and related Information Requirements. This included a review of P&OPEB practices of rate-regulators in other jurisdictions, a review of the role of other regulatory authorities in Ontario with respect to P&OPEB matters, and the results of other relevant research;
- **Section 2.4** provides accounting guidance for pension costs based on ASC 980 (US GAAP); and
- **Section 2.5** lists the Information Requirements identified for pension costs.

2.2 Methods Identified for Recovering Pension Costs

Costs relating to pension plans can be split into two categories:

- a) Costs relating to pension plans that are accounted for as defined contribution plans (“DC”), including multi-employer plans such as OMERS; and
- b) Costs relating to pension plans that are accounted for as defined benefit plans (“DB”). Within this category, the pensions costs can be further analyzed as:
 - i) Costs relating to registered pension plans; and
 - ii) Costs relating to unregistered pension plans, including SERP.

KPMG has considered the nature of the different types of pension plans and has identified proposals for how costs could be recovered through rates. The OEB may wish to consider adopting the following methods as the OEB’s policy for recovering costs relating to pension plans in the rates charged to customers:

Category of pension costs	Methods for recovering pension costs in rates
Pension plans that are accounted for as DC plans (including OMERS)	Consideration should be given to whether a utility should include in cost for purposes of determining rates the same cost value as is determined for accounting purposes.
Registered pension plans that are accounted for as DB plans	<ol style="list-style-type: none"> 1. Consideration should be given to whether a utility should include in cost for the purpose of determining rates for the current period in its rates rebasing application the amount of the employer's Modified Funding Contributions remitted, or forecast to be remitted, in respect of the period; 2. Consideration should be given to whether a utility should identify and demonstrate in its rates rebasing application the impact and appropriateness of including amounts in excess of Modified Funding Contributions in rates for the current and future periods; and 3. Pending the OEB's decision on disposition of any amount that is paid by a utility in excess of the Modified Funding Contribution amount, the excess amount that is paid by a utility shall be recorded in a separate deferral account, and shall attract a return¹.
Unregistered pension plans that are accounted for as DB plans	<p>Consideration should be given to whether a utility should include in cost for the purpose of determining rates the same cost value as is determined for accounting purposes.</p> <p>If the accounting framework that is used by a utility does not periodically reclassify to net income the component of pension costs that is recorded in OCI, consideration should be given to whether a utility should be required to record that amount in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the pension plan.</p>

¹ In this report the phrase 'attract a return' is used to indicate that the regulated entity would accrue a carrying charge on the balance that is recorded in the deferral account. If this method of recovering costs is adopted by the OEB, the OEB would need to determine the appropriate level of carrying charge that would be accrued on the deferral account.

The rationale for using each of these methods is detailed in Section 2.3 below. The methods that have been identified also inform the specific Information Requirements that have been identified in Section 2.5.

2.3 Rationale for the Methods Identified for Recovering Pension Costs

2.3.1 Overview of Section

This Section provides the rationale for the methods of recovering pension costs identified in Section 2.2 above. To facilitate an understanding of these identified methods and their rationale, KPMG provides the following information:

- Section 2.3.2 is a basic outline of how pension plans work. Included in Section 2.3.2 are references to Appendices A, B and C that present a more comprehensive explanation of how pension plans function and the different accounting treatment given to them under various accounting frameworks.
- Section 2.3.3 provides a summary of the results of the review of regulatory practices for P&OPEB costs in other jurisdictions.

Against the backdrop of a basic outline of how pension plans work and the results of the review of the regulatory practices in other jurisdictions, Section 2.3.4 provides the rationale for the methods of recovering pension costs identified.

2.3.2 Summary: Pension Plans in Ontario and their Costing

2.3.2.1 Summary of Costing of Utility Pension Plans

It is necessary to consider registered pension plan costs separately from non-registered pension costs primarily because pension plans in Ontario that are “registered plans”¹ are required to be funded in advance. The presence of a legislated funding framework warrants separate consideration, whereas non-registered pension plans, in all cases, do not have regulatory funding requirements.

Currently, there are two primary methods used by regulated utilities in Ontario to recover pension costs – legislated funding contribution (also referred to as the “cash basis” for pensions) and accrual accounting costs. The ‘pay-as-you-go’ payments method may be in use by only a very few regulated utilities in Ontario. These three methods are defined as follows:

- Funding contribution: the minimum amount of *contribution* required to be made by a sponsor of a registered pension plan subject to the requirements of pension legislation in Ontario under the PBA. *This method is not to be confused with the Modified Funding Contribution method that has been identified in this report as an alternative for the recovery of costs relating to registered pension plans that are accounted for as DB plans;*

¹ Registered with FSCO and the CRA.

- Accrual accounting cost: this is the accrued cost determined by accounting rules (in accordance with a given accounting framework) and recognized and reported in general purpose financial statements (ultimately split between capital expenditures, operating expenditures and OCI, where applicable); and
- ‘Pay-as-you-go’ payments: is equal to the benefit payment to the plan beneficiaries, as specified by the terms of the plan.

The normal ‘pay-as-you-go’ method has not been considered further in this report because it introduces significant concerns as it does not include in the current period’s rates a cost estimate for the obligation arising in retirement from employee service rendered in the current period and, for registered plans, the method does not consider the cash payments that a regulated utility is required to make to its pension plan under the PBA. Also, use of the normal ‘pay-as-you-go’ method would not allow utilities that have a finite life (such as certain nuclear power plants that are projected to shut-down in the medium-term) to fully recover projected future payments on pension obligations that extend well into the future.

The *funding contributions* and *accrual accounting cost* methods often produce significantly different values of cost, one of which (typically the accounting cost) is then allocated in the books of account of the utility between capital expenditures, operating expenditures and OCI, where applicable. The differences between funding contributions and accrual accounting costs are significant because they are defined by different frameworks which have specific and separate methodologies for setting assumptions and calculating costs. Indeed, there is no guarantee that one method will *always* result in higher (or lower) costs for a given period than the other. We note, merely for illustration purposes, the following differences between Ontario Power Generation Inc.’s historical and forecast pension costs as detailed in Table 21 of the OEB’s Decision with Reasons dated November 20, 2014.¹

\$million		2008	2009	2010	2011	2012	2013	Total	2014	2015
		Actual	Actual	Actual	Actual	Actual	Actual	2008-13	Plan	Plan
	Pension									
1	Accrual Basis - recoverable in (rates) payment amounts	121.4	141.4	150.1	195.0	286.1	383.3		471.3	405.3
2	Cash Basis	198.6	206.1	208.5	235.5	297.1	242.9		321.9	329.6
3	Difference (1-2)	(77.2)	(64.7)	(58.4)	(40.5)	(11.0)	140.4	(111.4)	149.4	75.7

Further, the accrual accounting cost method has differences that relate to different accounting requirements in the various accounting frameworks currently available for use in Canada – see details of these differences as set out in the simplified example that is provided in Appendix G.

¹ Extract from OEB Decision with Reasons, EB-2013-0321 dated November 20, 2014: Table 21, page 84.

That said, despite these periodic differences in pension cost amounts, in the fullness of time, the cumulative funding costs for a pension plan is generally expected to equal that plan's cumulative accrual accounting costs. This is true regardless of the accounting framework that is used by a regulated utility. As such, over time, a regulated utility that is allowed to also include in rates the amounts that are recorded in OCI would recover all its pension costs irrespective of the method that is used for setting rates.

As discussed in more detail in Section 2.3.3 below, some regulators allow the inclusion in cost for rate-setting purposes amounts equal to or based on accrual accounting cost while others allow amounts equal to or based on the amount of funding contribution, and not necessarily consistently among all utilities regulated by the same regulator.

2.3.2.2 Utility Pension Plans in Ontario

In Ontario there is a large pension plan of particular note for the industry. It is the Ontario Municipal Employees' Retirement System ("OMERS"). It provides pensioners with a defined benefit upon retirement and is thus a DB plan. However, because it is a multi-employer plan that is currently unable to identify the amount of invested funds that are attributable to an individual participating employer or the amount of specifically associated obligations, accounting rules require participating employers to recognize the amount of contributions to the OMERS pension fund as the pension cost for that financial reporting period. It is thus accounted for in the same way as a DC plan while in actual fact it is a DB plan. The majority of electricity distributors in Ontario are members of the OMERS plan.

The large utilities that are not members of OMERS are Ontario Power Generation, Hydro One (distribution and transmission), Union Gas and Enbridge Gas Distribution. Other smaller utilities that are not members of OMERS include Canadian Niagara Power Inc. (distribution and transmission utilities that are owned by Fortis Ontario) and four First Nation utilities¹. The large utilities that are not members of OMERS and IESO have DB plans that are funded in accordance with PBA requirements; the plans are accounted for as DB plans in their general purpose financial statements in accordance with the applicable accounting framework.

For a more detailed description of the various pension plans in Ontario and how they work, see Appendix A.

2.3.2.3 Changes and Trends Affecting Pension Plans

Against the above backdrop of different methods used by regulated utilities to recover pension costs in Ontario, there are two change dynamics that should be considered:

¹ The four First Nation utilities comprise of three distributors (Attawapiskat Power Corporation, Fort Albany Power Corporation and Kashechewan Power Corporation) and the electric transmission utility that they own equally, Five Nations Energy Inc.

- Changes occurring in accounting frameworks in Canada as utilities transition from legacy Canadian GAAP which is being phased out for rate regulated entities; and
- The likelihood for pension reform in Ontario.

Legacy Canadian GAAP has been replaced over a period of years by International Financial Reporting Standards (“IFRS”) for publicly accountable enterprises and, for other entities, GAAP such as Canadian Accounting Standards for Private Enterprises (“ASPE”), GAAP for not-for-profit enterprises and GAAP for public sector enterprises. Legacy Canadian GAAP (which, as mentioned previously, has been replaced by the other accounting frameworks), IFRS, United States Generally Accepted Accounting Principles (“US GAAP”) and ASPE are the principal accounting frameworks applicable to utilities in Ontario, with minor exceptions associated with IESO, First Nations and co-operative utilities that use either Canadian GAAP applicable to not-for-profit enterprises or Public Sector Accounting Standards – for the most part, the accounting requirements for retirement benefits under Public Sector Accounting Standards are similar to legacy Canadian GAAP.

In Ontario, regulated utilities are typically required to adopt IFRS unless the utility is successful in exempting itself in certain circumstances in favour of US GAAP, or is a user of ASPE. Some large utilities have been able to adopt US GAAP for their general purpose financial statements. However, in Ontario, a utility cannot adopt US GAAP for one area of accounting while adopting IFRS for another. The OEB has issued decisions approving the use of US GAAP for rate setting purposes for those utilities who have adopted US GAAP for their general purpose financial statements.

Thus, because there are different accounting frameworks that apply to utilities in Ontario, this report has considered the implications of some of their differences on P&OPEB costing. The differences are discussed more extensively in Appendix C and Appendix G. For pension plans, the methods for recovering pension costs identified in this report (specifically the methods set out in Section 2.2) actually reduce the need for detailed understanding of the differences between the various accounting frameworks because the methods proposed would require registered DB pension plans to use *Modified Funding Contributions*, not *accrual accounting costs*, in rate applications. There are instances where a regulated utility in Ontario would also have a non-registered DB pension plan. As *accrual accounting costs* are used in rate applications for such non-registered pension plans that are DB plans, it is still important to understand the accounting differences. However, generally, these non-registered DB pension plans tend to be much smaller in size and involve much lower total costs than registered DB pension plans.

The potential for pension reform in Ontario and trends elsewhere point in the direction of a move away from DB plans to DC plans and hybrid DB/DC plans (and other types of plans). This would transfer some or all of the risk of meeting the pension obligation from employers to individual employees and pensioners. In addition, there is potential consolidation of public pension plans in Ontario. These trends and developments and their potential implications are described in some detail in Appendix D. Where possible, the potential implications of these changes has been taken into account in identifying the proposed Information Requirements set out in this report.

2.3.3 Summary: Experiences and Practices in Other Jurisdictions

At the OEB's request, KPMG conducted a review of experiences and regulatory practices for P&OPEB costs in other jurisdictions. The detailed results of this review are set out in Appendix F. The review covered North American and selected international rate-regulators. The key results for both P&OPEB are summarized as follows:

1. There is only one regulator that has specified separate, distinct and well documented principles and guidance for utilities in its jurisdiction with respect to pension costs. That jurisdiction is Great Britain and the regulator is Ofgem. In 2003 Ofgem specified principles and stated its requirements for the costing of DB pensions in determining revenue requirement upon rebasing of rates. As is evident from the listing of the Ofgem principles provided in Appendix F, the principles involve general high-level ratemaking considerations for addressing pension costs, but do not provide the detail for the unique issues that arise from assessing pension costs and accounting for them well in advance of actual cash payments being made. Since 2003 the principles have not changed although the guidance has evolved somewhat. However, Ofgem does not have separate and distinct principles that set out how OPEB costs are included in determining revenue requirement. All other regulators rely on the general principles for rate-making in determining the P&OPEB costs that are included in setting rates;
2. The practice for recovering P&OPEB costs in the rates charged to customers varies significantly from jurisdiction to jurisdiction and, in some jurisdictions, the issue is dealt with on a case-by-case basis. As such, the regulatory practice can vary from utility to utility. Ofgem applies specialized methods for pensions which are more aligned with the funding basis. The methods parallel the funding basis as all its stakeholders are of the view that the funding cost of such long-dated obligations is far more important than amounts based on an accrual basis established for financial reporting purposes. The Ofgem method is a widely accepted practice in its jurisdiction and there have been no significant concerns raised by the regulated entities. On the other hand, the Federal Energy Regulatory Commission ("FERC"), British Columbia Utilities Commission ("BCUC") and Nova Scotia Utility and Review Board ("UARB") generally apply the accrual accounting basis for recovering P&OPEB costs in rates. FERC is of the view that regulatory and financial accounting have a common goal of attempting to allocate accrued costs between periods in a rational manner so that each period bears its equitable portion of costs. FERC also concluded that accounting standards provide a reasonable convention for the measurement of the accrued costs and can be applied uniformly by the regulated entities. As such, FERC's stated policy is to apply the accrual basis set out in financial reporting standards. However, individual State regulators across the US do not always follow a similar practice; their practices vary significantly from State to State and, in some States, the issue is dealt with on a case-by-case basis;

3. Many jurisdictions have been experiencing movement away from DB pension plans to DC plans, including in Great Britain, Australia and New Zealand. In Great Britain, the utility DB pension plans are closed to new entrants. In both Australia and New Zealand, utilities have used DC plans for a sufficiently long period of time that the amount of cost driven from legacy DB plans is not a significant factor in setting rates;
4. Regulators rely on actuarial reports as a basis to determine whether the P&OPEB costs that are recognized by a regulated utility are measured in a reasonable manner. The most comprehensive approach identified is in Great Britain where the regulator engages government actuaries to conduct a high-level review of actuarial reports submitted to Ofgem every three years. The review identifies utilities that have used outlying assumptions for particular scrutiny by Ofgem. Most other regulators review P&OPEB costs in the same manner as they do for any other costs. No regulators were identified that require alignment of the benefits provided by P&OPEB plans with other sectors of the economy, and no regulators were found that have undertaken an exercise to compare or benchmark plan benefits; for DB pension plans, as noted earlier many North American jurisdictions have permitted P&OPEB costs to be included in determining revenue requirement based on the accrual accounting cost method and in a few cases the funding contribution method. Sometimes a regulator within a particular jurisdiction is not consistent with regards to which method is used;
5. Regulators in several North American jurisdictions, notably FERC, British Columbia and Nova Scotia require the use of deferral and variance accounts to record approved differences between P&OPEB costs recognized on an accrual basis for financial accounting purposes and the amount permitted for inclusion in the rates charged to customers. Specifically, as FERC uses accrual accounting as the basis for recovering P&OPEB costs in rates (see item 2 above), regulatory balances are required to be recognized for the unamortized amounts that would otherwise be recorded in OCI pending future amortization and inclusion in rates;
6. No special incentives were found to be in place to reduce P&OPEB costs beyond the general incentive provided in an incentive rate scheme affecting all of a utility's costs; and
7. Some instances were found where P&OPEB plans included employees from non-regulated businesses. For these, rational allocation means were used to eliminate the costs relating to the non-regulated business from the P&OPEB costs that are included in setting rates.

2.3.4 Rationale for Modified Funding Contribution Method vs. Accrual Accounting Cost Method

Our review has identified two areas where there are different practical alternatives for pension costs that require further consideration. The first is the costing of registered pension plans accounted for as DB plans (typically single-employer pension plans). The second is the costing of unregistered pension plans (such as supplemental employee retirement pension plans (“SERP”) that are DB plans.

There are several aspects of pension plans accounted for as DB plans which give rise to the alternatives identified. The principal ones are:

1. The differences in the objectives of funding contribution based methods and accrual accounting cost methods, and the degree to which the objectives of one method may be more closely aligned with the objectives of rate regulation than the other; and
2. The variety of accounting frameworks that apply among regulated entities within Ontario (e.g., IFRS, ASPE and US GAAP) resulting in different accrual accounting cost under each accounting framework.

As mentioned in Section 2.3.2 above, the differences between funding contributions and accrual accounting costs can be significant because they are defined by different frameworks which have specific and separate methodologies for setting assumptions and calculating costs. Indeed, there is no guarantee that one method will *always* result in higher (or lower) costs for a given period than the other. However, despite these periodic differences in cost amounts, in the fullness of time, the cumulative cash (or funding) costs for a plan is generally expected to equal that plan’s cumulative accrual accounting costs. This is true regardless of the accounting framework that is used by a regulated entity. As such, over time, a regulated utility would recover all its pension costs irrespective of the method that is used to include these costs in rates.

The merits for using the funding contribution method (including the Modified Funding Contribution method) for registered single-employer DB pension plans and the accrual accounting cost method for non-registered DB pension plans are discussed further below. However, there seems to be no indication that the regulatory practices associated with including costs for DC pension plans, including DB plans accounted for as DC plans¹, in rates are not suitable in their present form. Further, as no other alternative approaches were identified by our review, no change has been identified for such DC plans.

¹ Concerning Multi-Employer DB Pension Plans (e.g., OMERS) – where individual plan member employer obligations and invested asset values cannot be separately identified by member employer (as is the case for OMERS member entities), they are treated as DC plans by the employer. DC accounting requires the employer to recognize the fund contribution payable for services rendered during the period. Therefore there is no difference between the funding contribution method and the accounting cost method for such plans - both lead to the same result.

2.3.4.1 Rationale for Registered Pension Plans Accounted for as DB Plans

Our review identified that utilities with registered pension plans that are classified and accounted for as DB plans (typically the single-employer DB pension plans) could be required to include in total expense for setting rates for a given period an amount based on a Modified Funding Contribution method, i.e. the funding contribution calculation governed by the PBA (the results of which are presented in actuarial valuation reports for funding purposes) but modified for certain specific components of special payments that would be recorded in separate deferral accounts pending a decision by the OEB. Such a Modified Funding Contribution method is different to the requirements of the funding contribution method and accrual accounting standards for general-purpose financial reporting. Detail regarding actuarial funding valuations is set out in Appendix A.

The annual contributions that are made by a regulated utility to its registered pension plan comprise of three components, depending on the plan's individual circumstances:

1. The employer's portion of the amount required to fund normal cost contribution calculated on the going concern basis. Both "normal cost" and "going concern basis" are defined terms under the PBA. The normal cost contribution is that amount which will, if set aside in a particular year and allowed to grow over a period of years, be sufficient to fund the portion of the pension promise arising because of the pensionable service of the eligible workforce for the year, all other things being equal. In general, this component is relatively stable;
2. Additional amounts required for "special payments" (also as defined in the PBA) needed to liquidate any deficit on a solvency basis ("solvency special payments") and any unfunded liability on a going concern basis ("going concern special payments using the 15-year amortization period"). In general, special payments can be very volatile as the special payment amounts typically arise due to changes over time in key assumptions or when the experience of the plan is less favorable than expectations. The going concern method recognizes the impact of these changes over 15 years as any going concern unfunded liability is liquidated over 15 years. However, the solvency method recognizes the impact of the changes over 5 years, which is the required period for liquidating any solvency deficit. The long-term nature of the going concern method results in special payments determined under this method being less volatile than those determined under the solvency method.

The sum of the normal cost contribution and the two components of special payments mentioned above represents the Minimum Required Contribution ("MRC") under the PBA; and

3. Additional amounts beyond the MRC that an employer may choose to make. In some instances, it can be to the utility's advantage to contribute in excess of the MRC for strategic reasons. The strategic reasons typically include consideration of such factors as: the corporate tax benefits, market risk management strategy for fund assets, lower Pension Benefits Guarantee Fund ("PBGF") fees and the potential to avoid the necessity of an annual funding valuation. An employer may choose to make additional contributions beyond the MRC if a larger tax

deductible contribution is permitted under federal income tax legislation than is required to meet the MRC. Under the Income Tax Act, the maximum tax deductible pension contribution that an employer is permitted is the greater of the going concern and the hypothetical wind-up deficit, plus the normal cost (as defined under the PBA). The nature of this component of funding contributions makes it volatile.

As the sum of these three components represents a regulated utility's 'cash costs' for each annual period, this total amount could be used to represent the pension cost that is included in total expense for establishing rates for each period. However, our review has identified that the amount that a utility could be required to include in total expense for rate-setting purposes could comprise the funding contribution outlined in 1) above, plus the going concern special payments using the 15-year amortization period. The sum of these two amounts is hereafter referred to as the "Modified Funding Contribution" amount. Any funding contributions in excess of the Modified Funding Contribution amount would be recorded in a separate deferral account. Pending the OEB's decision on how to dispose of any amount that is paid by a utility in excess of the Modified Funding Contribution amount, the excess payment would attract an appropriate return that takes into account issues such as the period of its recovery and market interest rates.

As such, any payments in excess of the Modified Funding Contribution amount would be subject to additional review by the OEB on the timing of their inclusion in current and future rates. In this way, depending on the justification that is provided in rates rebasing applications, the OEB would be able to mitigate or significantly reduce the volatility that is often associated with the traditional funding contribution method.

Further, demonstrating that components in excess of the MRC are justified for inclusion in the current period's rates means that the utility in its rates application could be required to provide evidence showing that including the amounts above the MRC in the current period's rates is congruent with the interests of customers.

Using the Modified Funding Contribution method instead of funding contributions or accrual accounting cost would represent a change for the large utilities in Ontario.

2.3.4.1.1 Pros and Cons of Using the Modified Funding Contribution Method for Registered Pension Plans Accounted for as DB Plans

The primary arguments in favor of using the Modified Funding Contribution method (as described above) for establishing customer rates instead of the accrual accounting cost method are as follows:

1. The Modified Funding Contribution amounts are more understandable since the path from costs to amounts included in customer rates (audit trail) is less complex. It is therefore easier to explain to stakeholders in a rates proceeding. Unlike the accrual accounting cost method, there is no need to identify and establish alternatives for possible set-aside mechanisms in order to provide customers with 'value-for-money' on the cash that is collected by utilities in advance of cash

disbursements being made on the pension obligations (i.e. excess recoveries) – see additional discussion in Section 3.4.

2. The Modified Funding Contribution amount results in greater comparability among utilities since costs in rates do not depend on the accounting standards that are used by a utility. The different accounting requirements among the various accounting standards (which result in different accounting cost) are eliminated as a source of variability. The Modified Funding Contribution amount is not subject to change when individual accounting standards evolve because its calculation is independent of these accounting standards.
3. Assumptions are determined more independently than with the accounting cost basis. Under the Modified Funding Contribution method assumptions are set by the actuaries (with input from the utility management), and the assumptions are subject to review by FSCO. Under the accrual accounting basis, the assumptions are set by management with input from actuaries.
4. The corridor method used for accrual accounting under US GAAP only amortizes and recognizes amounts that are outside the 10% corridor. Amounts that are inside the 10% corridor are typically not amortized and recognized until the last pension obligation has been settled. This could cause issues relating to which generation of customers should pay for which costs and, depending on the room available within the 10% corridor, reduces period-to-period comparability of accounting costs between entities. Under IFRS, remeasurements of a net defined benefit liability are recorded in Other Comprehensive Income, and the amounts are not reclassified to profit or loss in a subsequent period – as such, the remeasurements would not be included in rates and possibly leading to concerns about which generation of customers should pay for which costs. Although some smoothing exists in the Modified Funding Contribution method, it does not have similar use of the 10% corridor like US GAAP or Other Comprehensive Income like IFRS.

The argument against using the Modified Funding Contribution method, and which favors the accrual accounting cost method, is that the going concern funding basis includes an element of conservatism, while the accrual accounting cost method does not necessarily include this. The use of conservative assumptions when calculating normal cost contributions and going concern special payments could bring costs forward in time also causing potential concerns about which generation of customers should pay for which costs.

It should be noted that if the OEB were to choose to require that all utilities use the Modified Funding Contribution method for establishing customer rates instead of the accrual accounting cost method, this would represent a change for all the utilities whose rates are currently set using the funding contribution method or the accrual accounting cost method. However, the utilities participating in OMERs would be unaffected. There would also be a difference that arises on transition to the new requirements. The proposed public consultation could consider if a generic approach could be applied in dealing with the difference on transition or this could be addressed on a case-by-case basis

(for example, if the difference on transition is material, the OEB could require that each utility propose a method of disposition for consideration by the OEB).

The particulars of using the Modified Funding Contribution method for establishing customer rates have been included in the Information Requirements provided under general stated objective # 6, “*P&OPEB costs are recovered over an appropriate time period*”, and general stated objective # 1, “*P&OPEB costs provide value for money*”.

2.3.4.2 Rationale for Non-registered Pension Plans Accounted for as DB Plans

As there is no regulatory funding requirement for non-registered pension plans, most utilities in Ontario recover these pension costs based on the accrual accounting cost method, with very few, if any, based on the ‘pay-as-you-go’ cash payments method. As discussed earlier, the ‘pay-as-you-go’ cash payments method has not been considered further in this report.

Utilities could be required to continue the use of the accounting cost method for determining the cost of non-registered pension plans to include in total cost for purposes of establishing rates.

However, the different accounting frameworks treat certain components of pension costs differently. Specifically, for IFRS, the component of pension costs that is recorded in Other Comprehensive Income (OCI) is not periodically reclassified to net income. Consideration should be given to whether a utility should be required to record the amount that is required to be recorded in OCI in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the pension plan.

This has been included in the Information Requirements provided under general stated objective # 6, “*P&OPEB costs are recovered over an appropriate time period*”.

2.3.4.2.1 Pros and Cons of Using the Accounting Cost Method for Non-registered Pension Plans Accounted for as DB Plans

The accounting cost method includes one major element of cost that is omitted from the ‘pay-as-you-go’ cash payments method, therefore making it more appropriate to use. The ‘pay-as-you-go’ cash payments method does not include in the current period’s rates a cost estimate for the obligation arising from employees service rendered in the current period; the cost is payable in retirement. It only includes costs incurred on payments to retirees (i.e. post-employment or post-retirement). There is no amount included relating to the obligation that was generated during an employee’s working years. Thus, it introduces significant concerns about which generation of customers should actually pay for the costs.

Most, if not all, utilities have already adopted the accrual accounting cost method required by accounting standards for including non-registered pension plan costs in their rate applications. It should, however, be noted that using the accrual accounting cost method to include in rates pension costs relating to non-registered plans creates the need to consider, identify and establish alternatives for possible set-aside mechanisms in order to provide customers with ‘value-for-money’ on the cash that is collected by utilities in advance of cash disbursements being made on the pension obligations (i.e. excess recoveries) – this is similar to the discussion in Section 3.4 for OPEB costs that are included in rates using the accrual accounting cost method.

2.3.5 Previous Decisions by the OEB Regarding Pension Plans

To date the OEB has not established *generic* industry-wide variance accounts for Pension (or OPEB) related cost variances. However, in the following four instances the OEB authorized utility specific variance or deferral accounts on a case-by-case basis and upon request by the utility:

1. Ontario Power Generation: for the variance between the Pension and OPEB costs included in rates and the amounts recognized on an accrual basis of accounting. In EB-2011-0090, the OEB approved a Pension & OPEB Cost Variance Account to record the difference between amounts in rates (forecast on accrual basis) and the actual accrual amounts. This account ceased operation on October 31, 2014. In EB-2013-0321, the OEB ordered payment amounts based on funding requirement for pension and cash for OPEB and established two new accounts to give effect to the new requirements;
2. Hydro One (Transmission and Distribution): for pension cost only. The account is called a Pension Cost Differential Account and was approved in 2004. The amount accumulated in the account is the difference between the forecast pension contributions amount included in rates and the actual pension contribution amount incurred on a funding contribution basis;
3. Enbridge Gas Distribution: EB-2011-0354 – for the variance between forecast pension and OPEB amounts included in rates and the actual amounts recognized on an accrual basis of accounting; and
4. Enersource Hydro Mississauga: in its 2013 Cost of Service Decision EB-2012-0033, this utility was granted an OPEB deferral account to capture material actuarial gains and losses when it transitioned to modified IFRS.

Several other utilities have also been granted permission by the OEB to set up deferral accounts for cumulative actuarial gains and losses that arise under their accounting framework. There have also been deferral or tracking accounts authorized by the OEB for several utilities for pension and OPEB related costs that arose because of the transition to another accounting framework as legacy Canadian GAAP is replaced (e.g. by IFRS or US GAAP in some cases). However, those transition accounts were part of the broader transition to a new accounting framework, not explicitly related to the underlying principles applicable to P&OPEB accounting. They are therefore not relevant to this discussion.

Since the OEB's decision on OPG to embed in rates the forecast funding contribution amount for pension costs, and the forecast cash amount for OPEBs (along with tracking accounts to capture the differences with the accrual method for both), the OEB has approved a similar approach for OPEBs for several electricity distributors pending the outcome of the proposed public consultation.

It should be noted that in granting a generic deferral or variance account the OEB has typically considered a number of specific factors, including the extent of management control over the issue, materiality, past practice (including practices of others) and weighed the extent to which the underlying risk should be borne by the utility versus the customer. There is no doubt that there are variables outside the control of management, at least in the short term, that affect P&OPEB costs (e.g., longevity, discount rates, market returns on plan assets, etc). As pension costs are an estimate of the costs that will be incurred in the future, it is not possible to establish precise measurement of the cost relating to an individual period; the costs are established by using estimates and assumptions that fall within an acceptable range (often as identified and recommended by the utility's actuary after taking into account accepted actuarial practice and any applicable laws). In some instances, a utility's management may be able to impact the accounting costs that are recognized by the utility as a result of selecting specific actuarial assumptions within these acceptable ranges. Further, in the long-term, management can influence the choice of benefit plan design in such a way as to mitigate many of the risks and related costs.

The current Board's ratemaking policy is generally not to permit any true-up of the costs for operating and capital expenditure and load forecasting that are included in the test-year revenue requirement that is approved by the OEB in a rate decision and order subsequent to a rate application proceeding. Costs that are forecast by a utility and included in its rate application are based on a number of assumptions; actual experience may differ from these assumptions e.g. a change in a utility's staffing complement, planned operation and maintenance activities, customer base, load growth, weather, capital programs, etc. However, these forecasted costs are not adjusted to reflect actual amounts although the costs are subject to scrutiny by the OEB in the next cost of service rate application proceedings. The decision whether to treat P&OPEB costs differently from other costs that are included in rates on a forecast basis and grant generic deferral or variance accounts to capture differences between the amounts included in rates and the actual amounts incurred is that of the OEB.

However, if the OEB were to choose to adopt the Modified Funding Contribution method as discussed in Section 2.3.4.1 above, it would be necessary for it to also approve the use of a generic deferral account for components of the funding contribution to registered pension plans that is not currently included in rates. This is because the Modified Funding Contribution method seeks to mitigate or significantly reduce the volatility that is often associated with the traditional funding contribution method. Components of funding contribution payments would be deferred and only included in rates in a future period as determined by the OEB; specifically, pending the OEB's decision on disposition of any amount that is paid by a utility in excess of the Modified Funding Contribution amount, the portion of the excess payment would attract an appropriate return.

2.4 Accounting Guidance for Pension Costs based on ASC 980 (US GAAP)

The accounting guidance that is set out in this Section of the report specifically relates to those regulated entities that prepare their general purpose financial statements in accordance with US GAAP. The intent of this section is to provide guidance on the impact on a utility's financial reporting of using the 'pay-as-you-go' method for setting rates and to determine under what conditions accounting standards could prohibit the recognition of regulatory assets if a method other than the accrual accounting cost is used to recover pension costs in rates.

It is important to note that regulated entities that prepare their general purpose financial statements in accordance with legacy Canadian GAAP and ASPE, as well as those regulated entities that are eligible to elect to apply the requirements of IFRS 14 and elected to do so when they adopted IFRS (see Section 1.5 of Appendix C), generally all recognize regulatory deferral and variance accounts in accordance with the US GAAP accounting principles set out in ASC 980. As such, in most instances, this accounting guidance is also equally applicable to the regulated entities that report under these three accounting frameworks.

2.4.1 General guidance applicable to both P&OPEB costs

Under US GAAP, entities that have activities that are subject to rate regulation are required to follow special accounting provisions which are set out in ASC 980. These special accounting provisions require the economic effect of rate regulation to be reflected in general purpose financial statements prepared under US GAAP. It is important to note that if an entity falls within the scope of ASC 980, it is required to prepare its financial statements based on these special accounting provisions; it cannot choose to apply the accounting provisions that apply to entities that are not subject to rate regulation. The criteria to fall within the scope of ASC 980 is set out in Section 1.1 of Appendix K.

The utilities that are regulated by the OEB have concluded that they meet this criteria, and as such, those utilities that report under US GAAP follow the special accounting provisions set out in the various Sub-Topics of ASC 980. This results in the recognition of regulatory assets and liabilities.

It is, however, also important to note that a regulator cannot eliminate a liability that was not imposed by its actions. As such, although certain costs relating to obligations may be fully recoverable through the rates charged to customers in the future (for example, obligations relating to deferred taxes, P&OPEB and asset retirement obligations), a regulated entity still recognizes the obligations on its balance sheet.

By their very nature, P&OPEB obligations can remain outstanding for a very long time. For this reason, regulators establish various methods for including these costs in the rates charged to customers. The methods used can include funding contribution method, accrual accounting or 'pay-as-you-go'. If the amount determined by accrual accounting is not used for setting rates, a difference will exist between the net periodic cost determined under the method used for rate-making purposes

and the amount recognized in general purpose financial statements. In order to reflect the economic impact of rate regulation in general purpose financial statements, ASC 980 requires that regulated entities recognize the regulatory assets and liabilities as discussed further below.

All this means that for P&OPEB, a regulated entity is required to first apply the accrual accounting Topic that applies to all entities in general (i.e. ASC 715, *Compensation – Retirement Benefits*, with the relevant Sub-Topics being ASC 715-30, *Defined Benefit Plans – Pensions*, for pension obligations and ASC 715-60, *Defined Benefit Plans – Other Postretirement*, for OPEB obligations). Thereafter, any difference between the accounting treatment required by these accrual accounting Sub-Topics and the treatment adopted in setting rates is recognized by way of a secondary step, resulting in regulatory assets and liabilities as appropriate.

The rest of the discussion in this Section of the report focuses on whether regulatory assets and liabilities can be recognized on such P&OPEB differences.

Regulatory Assets (ASC 980-340)

ASC 980 defines an ‘*incurred cost*’ as a cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and has been or must be paid for. As such, ‘*incurred cost*’ includes costs that have been paid already as well as those for which an obligation to make a payment in the future exists as at the reporting date. This is consistent with the accrual accounting principles used in preparing general purpose financial statements.

The P&OPEB costs that are recognized in an entity’s general purpose financial statements represent management’s best estimate of the benefits that will be provided in future periods (i.e. post-employment) for services rendered by the employees as at the reporting date. Although this point-in-time measurement of the estimated obligation involves significant judgement and uncertainty, and it is quite possible that certain recognized amounts may decrease or reverse¹ when the obligation is re-measured in subsequent periods prior to cash actually being paid by the regulated entity, the recognized amounts nonetheless represent management’s best estimate of the obligation up to and as of the reporting date. For this reason, under ASC 980, P&OPEB costs determined using accrual accounting principles are included in the definition of ‘*incurred cost*’, and any regulatory asset that is recognized for such P&OPEB costs would inherently include estimation and measurement risks from the underlying obligation.

Note also that the definition of ‘*incurred costs*’ that is used for accrual accounting may at times differ from the criteria that are used by regulators in assessing whether a cost is actually included in the rates charged to customers during a particular period. For example, in setting rates, a regulator

¹ The recognized amounts may decrease or reverse due to issues such as the effect of differences between the previous assumptions and what has actually occurred (i.e. experience adjustments), and changes in demographic assumptions (e.g. mortality rates, employee turnover rates, claim rates, etc.) and financial assumptions (discount rates, benefit levels, increases in the cost of benefits provided, etc.) used to measure the obligation.

may conclude that certain costs that have been recognized under accrual accounting do not yet meet its criteria for inclusion in the rates because the amounts are not due to be paid before the next rate application. Although such costs would meet the definition of ‘*incurred costs*’ for accrual accounting, they would not meet the definition that is used for setting rates. Under ASC 980, costs relating to such differences in treatment between accrual accounting and ratemaking are included in the definition of regulatory assets, and would be recognized (or capitalized) if the criteria discussed further below are met. In this Section of the report, all further references to ‘*incurred costs*’ relate to the definition that is used for accrual accounting and not a different definition that may have been used for ratemaking.

Under the general provisions of ASC 980-340, *Other Assets and Deferred Costs*, an incurred cost that would otherwise be charged to expense is capitalized as a regulatory asset if:

- a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes; and
- b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator’s intent clearly be to permit recovery of the previously incurred cost.

Based on this requirement, a regulatory asset is only recognized if it is probable that the incurred cost will be recovered in future rates. ASC 450 states that an event is probable if it is “*likely to occur*”. As such, in order for incurred costs to be capitalized as regulatory assets, there needs to be suitable evidence to support the judgmental criteria that recovery in future periods is reasonably assured. In assessing that probability, reporting entities consider (1) how the costs are being recovered in rates and on what basis they are being recovered; (2) any specific actions by the regulator with respect to similar deferred costs; (3) the regulator’s historical approach to inclusion of such costs in rates; and, (4) whether there is significant uncertainty indicated by the regulator regarding the future rate recovery approach. Recovery of costs on a US GAAP accrual basis as well as the implementation of a tracker mechanism by the regulator (which allows the entity to track the actual costs as compared to the amount being recovered and to currently recover those actual costs from customers) are strong indicators that recovery from future rates is probable.

If it is not probable that an incurred cost will be recovered in future rates, a regulatory asset is not recognized at the time that a cost is incurred. Instead, a regulatory asset is recognized when it does meet the criteria at a later date.

Regulatory assets are not measured at discounted present value if the related cost will be recovered over an extended period without a return on the unrecovered amount. After determining that an incurred cost is treated differently for ratemaking and that it is probable that the incurred cost will be included in future rates, the amount that is recognized as a regulatory asset is not further adjusted to reflect the time value of money. However, an entity discloses the remaining amounts of such regulatory assets and the remaining recovery period applicable to them.

Regulatory Liabilities (ASC 980-405)

Regulatory liabilities arise from rate actions of a regulator that impose obligations on a regulated entity to its customers. ASC 980-405, *Liabilities*, addresses the accounting requirements for regulatory liabilities.

Regulatory liabilities typically arise for P&OPEB if a regulator provides current rates intended to recover costs that are expected to be incurred in the future with the understanding that, if those costs are not incurred, future rates will be reduced by corresponding amounts. The current rates are intended to recover such costs and the regulator requires the entity to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The usual mechanism used by regulators for this purpose is to require the regulated entity to record the anticipated cost as a liability in its regulatory accounting records, and the amounts are taken to income only when the associated costs are actually incurred and recognized as expenses. Typically, all these requirements would be specified beforehand and included in the rate orders/decisions issued by the regulator.

2.4.2 Guidance for Pension Costs

As indicated in Section 2.4.1 above, an employer with regulated operations accounts for the effects of applying Sub-Topic 715-30 for financial reporting purposes even if another method of accounting for pensions is used for determining allowable pension cost for rate-making purposes. However, the special accounting provisions that are applicable to the pension cost of regulated entities (ASC 980-715) **require** that the difference between net periodic pension cost as defined in Sub-Topic 715-30 and amounts of pension cost considered for rate-making purposes be recognized as an asset or a liability created by the actions of the regulator. Those actions of the regulator change the timing of recognition of net pension cost as an expense; they do not otherwise affect the requirements of that Sub-Topic.

However, ASC 980-715-55-4 also states that any regulatory asset or liability that is recognized for differences between pension costs determined for rate-making purposes and those determined under Subtopic 715-30 should also meet the general judgmental criteria for regulatory assets (ASC 980-340) and regulatory liabilities (ASC 980-405) – see Section 2.4.1 above. As such, like any other regulatory asset, regulatory assets relating to pension obligations are only recognized if it is probable that the cost will be recovered in the rates that will be charged to customers in the future.

Determining whether it is probable that the difference in pension costs will eventually be included in rates is often the most difficult part of applying these accounting requirements to pension regulatory assets. Recovering pension costs in rates on the basis of ‘pay-as-you-go’ clearly increases the level of judgment that a utility’s management (as the preparers of the utility’s financial statements) is required to make in recognizing regulatory assets, and can be a significant negative factor; on the other hand, rate-setting methods that closely resemble accrual accounting involve far less judgment in this regard. Recovering pension costs using the funding contribution method

involves less judgment than the ‘pay-as-you-go’ basis. Auditors opine on the utility’s financial statements, including judgments made with regards to recognized and unrecognized regulatory assets.

Nonetheless, if it is determined that it is probable that the difference will be included in rates, a regulated entity would be compelled to recognize the resulting pension regulatory asset. In fact, the Implementation Guidance that is set out in ASC 980-715-55-5 states that “*Usually, continued use of different methods for rate-making purposes and general-purpose external financial reporting purposes would result in either the criteria in paragraph 980-340-25-1 being met (i.e. regulatory assets recognized) or the situation described in paragraph 980-405-25-1(b) (i.e. regulatory liabilities recognized).*” Other than the following situations which are described in the Implementation Guidance, ASC 980-715 does not identify any other situations in which regulatory balances are not recognized for pension obligations:

- a) If it is probable that the regulator soon will accept a change for rate-making purposes so that pension cost is determined in accordance with accrual accounting methods (i.e. Subtopic 715-30), regulatory assets are not recognized if it is not probable that the regulator will provide revenue to recover the excess cost that results from the use of accrual accounting methods (i.e. Sub-Topic 715-30) for financial reporting purposes during the period between the date that the employer adopts that Sub-Topic and the rate case implementing the change; and
- b) If it is probable that the regulator soon will accept a change for rate-making purposes so that pension cost is determined in accordance with Subtopic 715-30, regulatory liabilities are not recognized if the regulator will not hold the employer responsible for the costs that were intended to be recovered by the current rates and that have been deferred by the change in method and the regulator will provide revenue to recover those same costs when they are eventually recognized under the method required by Subtopic 715-30.

Impact of pension amounts recognized in Other Comprehensive Income

ASC 715 permits costs relating to actuarial gains and losses and past service costs to be deferred as part of other comprehensive income (“OCI”) and accumulated within other comprehensive income (“AOCI”). These amounts are recognized in the profit or loss of a subsequent period. A question arises whether regulatory balances should also be recognized for such costs/surpluses at the time the amounts are recognized in OCI. This is complicated by the fact that the accounting guidance in ASC 980 pre-dates the changes in US GAAP that required the recognition of these costs in OCI.

ASC 980-340-25-1 states that a cost must be “incurred” in order to qualify for deferral as a regulatory asset. ASC 980 defines “incurred cost” as “*a cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and has been or must be paid for.*” In this case, the amounts recognized in OCI arise from the projected liability to employees for services rendered. The obligation to pay employees in the future meets the definition of an incurred cost, and therefore the amounts in OCI qualify for deferral as regulatory assets.

Section 1.1 of Appendix I shows the accounting practices by those entities that have recognized regulatory assets for the amounts in OCI by using this approach.

In order to provide clarity on this issue, FERC issued specific guidance to the entities that it regulates. This FERC guidance requires the entities that it regulates to recognize a regulatory asset for the minimum pension liability otherwise chargeable to AOCI – see Section 1.1 of Appendix J for additional details. In order to reduce diversity in practice, the OEB should consider issuing similar guidance for those regulated entities that recognize regulatory balances under their accounting framework.

2.4.3 Use of the ‘pay-as-you-go’ method or other methods of recovery for pension costs

As detailed above, ASC 980 does not specify additional criteria that would have to be met if a regulator were to use the ‘pay-as-you-go’ method, or any other method (including, for example, a predetermined fixed amount), for ratemaking purposes. In order to recognize a regulatory asset relating to pension costs, a utility is only required to determine whether it is probable that the difference in pension costs will eventually be included in rates. Recovering pension costs in rates on the basis of ‘pay-as-you-go’ clearly increases the level of judgment that a utility’s management is required to make in assessing if the regulatory assets relating to pension costs will be recoverable, and can be a significant negative factor; on the other hand, rate-setting methods that closely resemble accrual accounting involve far less judgment in this regard.

It should, however, be noted that using the ‘pay-as-you-go’ method, or any other method that has significant differences from funding contributions or accrual accounting cost, could introduce significant concerns about which generation of customers should actually pay for the costs. In addition, an appropriate recovery mechanism would have to be established to deal with the minimum funding contributions that utilities would still be required to make on their registered pension plan obligations. For these reasons, the ‘pay-as-you-go’ method of recovering pension costs has not been considered further in this report.

2.4.4 Transitional regulatory liabilities upon switching from accrual accounting to ‘pay-as-you-go’

If the OEB was to switch to the ‘pay-as-you-go’ method for ratemaking purposes, it would be important to also consider how the OEB would treat the cumulative amount that regulated entities have already collected from customers in rates charged so far. It would be necessary to ensure there is no windfall gain for regulated entities and customers do not pay for the same cost twice. It would seem improbable that the OEB would not hold the regulated entities responsible for the amounts collected to date and yet also allow the full amount of the pension costs to be recovered in future

rates when the costs are eventually paid. As such, it would seem likely that regulated entities would have to record transitional regulatory liabilities if the basis of recovery were to be switched from accrual accounting to 'pay-as-you-go'. Half of the stakeholders that provided initial written submissions to the proposed Consultation specifically agreed that customers, utilities, shareholders and employees should be kept whole if any changes were to be made to the method for recovering P&OPEB costs.

However, if the OEB were to decide to not hold regulated entities responsible for the amounts collected to date and, at the same time, allow the pension costs to be recovered in full when the costs are eventually paid in the future, the regulated entities would clearly benefit from double collection of the same cost (i.e. from the amount recovered from customers in rates so far, and again when the costs are eventually paid on the 'pay-as-you-go' basis that would be implemented after the change-over).

2.4.5 Actions that the OEB could take to influence the recognition of regulatory assets for pension costs

As the regulator of utilities in Ontario, certain actions that are taken by the OEB can influence whether regulated entities will recognize regulatory assets relating to pension costs. These regulatory actions could include:

- a) As detailed in Section 2.4.1, before an incurred cost can be recognized as a regulatory asset, it should be probable that the incurred cost will be recovered in future rates. The criteria for 'probable' is judgmental. Clearly, any guidance that is issued by the OEB that provides additional assurance that pension costs, including amounts in OCI, will be included in future rates would be of great help to the regulated entities. The OEB could also provide additional guidance with regards to the transitional adjustment relating to the change-over to the Modified Funding Contribution method that is detailed in Section 2.3.4 above. Such additional guidance need not limit the OEB from reviewing the reasonableness of the elements of pension costs included in future rate proceedings, but potentially could greatly reduce uncertainty regarding future recovery of pension costs; and/ or
- b) Like FERC, the OEB could issue general policy guidance with respect to the future regulatory treatment of pension costs that are recognized in OCI – see Section 2.4.2.

2.5 Information Requirements Identified (with supplementary explanatory statements)

KPMG has identified the following Information Requirements that would support the regulatory review of pension costs. In some instances, the Information Requirements represent documentation of existing requirements that have not been previously part of the OEB's regulatory requirements. For example, some individual utilities may already have been required to submit some of the Information Requirements as part of their separate rate applications. As such, some of the Information Requirements are documentation of existing practice. However, in other instances, the Information Requirements do result in new regulatory filing and reporting requirements. The impact may be significant; details of the extent of the changes and impact of those changes can only be determined on a case by case basis.

Also included in the Information Requirements are information disclosure matters that, if adopted by the OEB, would allow the OEB, intervenors and other interested parties to ensure that sufficient information is made available in rate setting proceedings. The specific circumstances include: situations where non-utility employees are members of pension plans that also include utility employees; utility re-organizations and plan restructurings; and, the effects of changes by a utility in its choice of accounting framework (e.g., IFRS vs US GAAP, etc).

The proposed public consultation may wish to consider some or all of these Information Requirements.

The Information Requirements may be summarized into six categories or general stated objectives as detailed below. If adopted, the OEB may find it useful to monitor and evolve the Information Requirements over time to ensure that they remain relevant and effective and to adapt to changes in legal, accounting or other regulatory requirements such as changes to the PBA.

*Note: Following each general stated objective below are indented numbered paragraphs. The paragraphs in **boldface font** are proposed Information Requirements for utilities to submit to the OEB. Paragraphs that are not in boldface font are background information and explanatory statements..*

1. **Pension costs provide value for money** - As part of competitive compensation costs, customers should expect to pay pension costs that provide value for money and are in line with comparative benchmarks.

Background Information

- 1.1 Pension plans are provided to employees as components of employee compensation plans. Compensation plans should be designed to allow the employer to attract and retain appropriately skilled staff. At the same time, utilities should not expect to pass on to

customers excess costs of providing benefits that are not in line with sector practice or to pass on to customers excess costs that could be avoided by efficient management actions.

- 1.2 The OEB's mandate includes ensuring customers receive value for money for utility spending on pension plans. Pension costs are components of overall compensation cost and, as such, it is not reasonable to assess value for money for pension costs in isolation.
- 1.3 Pension plan administration and asset management costs, such as the fees paid to investment advisors and actuaries, may be paid directly by utilities or from the benefit plan. Utilities may also be required to pay Pension Benefits Guarantee Fund ("PBGF") fees or may pay fees in respect of letters of credit used to satisfy solvency special payment requirements.
- 1.4 DB pension Modified Funding Contribution amounts in respect of the employer's normal cost contributions and going concern special payments using the 15-year amortization period as described in 1.5 below represent the direct costs attributable to a given period.
- 1.5 "Special payment" amounts may be necessary to meet funding contribution requirements in addition to normal cost contributions. Special payments include amounts required to liquidate any going concern unfunded liability (i.e. determined using the going concern method of calculation) or to liquidate any solvency deficiency (i.e. determined using the solvency method of calculation). The going concern and solvency calculations are determined in accordance with the requirements of the Pension Benefits Act and its regulations ("PBA"). Any such special payment amounts typically arise due to changes over time in key assumptions or when the experience of the plan is less favorable than expectations. As such they are less related to a given period and could also be a result of management actions. The going concern method recognizes the impact of such changes over 15 years, by requiring the liquidation of any going concern unfunded liability over 15 years, whereas the solvency method recognizes the impact over 5 years, by requiring the liquidation of any solvency deficiency over 5 years; this results in the special payments determined under the going concern method being less volatile than the solvency method. The PBA allows the use of letters of credit for funding of solvency deficits. Accordingly, solvency special payment amounts and letter of credit fees incurred or forecast to be incurred need to be assessed as to whether they are included in rates for the current period based on the impact on rates for the current and future periods. Going concern special payments using the 15-year amortization period shall be included in rates for the period that they are forecast to be paid.
- 1.6 As well as required normal cost contributions and special payments, a utility may choose to contribute additional amounts to fund DB pension plans up to limits established by income tax legislation. The OEB should assess whether any such additional amounts incurred or forecast to be incurred are included in rates for the current period based on the impact on rates for the current and future periods.

Information Requirements

- 1.7** In order to ensure utilities have appropriate incentive to manage their pension costs, consideration should be given to whether a utility should demonstrate that its total compensation costs and compensation strategy are in line with sector practice. This can be demonstrated through benchmarking. Utilities may find cost-effective ways to obtain appropriate comparators and cost benchmark information through participation in industry associations.
- 1.8** Consideration should be given to whether all administration and pension asset management costs, PBGF fees and fees in respect of letters of credit used to satisfy solvency special payment requirements of a utility should be provided as part of rate rebasing applications. Consideration should be given to whether all such costs must be categorized as pension costs regardless of whether they are paid directly by the utility or from the DB plan.
- 1.9** Consideration should be given to whether a utility should monitor its compensation cost benchmark performance over time and its cost performance to demonstrate continuous improvement and that it is delivering value for money for customers.
- 1.10** Where a utility makes funding contributions to DB pension plans in excess of minimum amounts required by the PBA and the Financial Services Commission of Ontario (“FSCO”) to fund the sum of normal cost contributions and going concern special payments using the 15-year amortization period i.e. the “Modified Funding Contribution amount”, consideration should be given to whether the utility is required to justify its funding contributions and explain the reasons for each major component of any payment in excess of the Modified Funding Contribution amount and identify and demonstrate the impact of each component on current and future rates in its rates rebasing application. Pending the OEB’s decision on disposition of any amount that is paid by a utility in excess of the Modified Funding Contribution amount, consideration should be given to whether the excess amount that is paid by a utility shall be recorded in a separate deferral account, and shall attract a return.
- 1.11** Where a utility provides enhanced benefits under early retirement or other severance arrangements, consideration should be given to whether the utility should be required to demonstrate the value of the enhancements and impact on customers in its rates rebasing application.
- 1.12** Consideration should be given to whether a utility should be required to provide evidence in its rates rebasing application that identifies separately the amount of cost arising from any plan directed to special categories of employees such as a supplementary executive retirement plan(s). Consideration should be given to whether such evidence must identify the amount contributed by employees to any such

plan(s) and describe the basis of determining the amount included in rates (i.e., accrual accounting, funding contribution, pay-as-you-go cash payment or other methods as may have been approved by the OEB).

1.13 Consideration should be given to whether a utility should be required to provide evidence in its rates rebasing application that identifies separately the amount of cost arising from any changes made to pension plans that reference employee services rendered in the past.

2 *Governance for pension plans reflects best practices – Pension plans should be subject to a high standard of governance addressing oversight, investment management, and administration.*

Background Information

2.1 The objective seeks to provide increased confidence that customers are not bearing the costs of poor pension cost management and that pension plan risks are appropriately addressed.

2.2 There are regulatory agencies with oversight responsibilities regarding pension plans in Ontario. These include FSCO and Canada Revenue Agency (“CRA”). In addition professional bodies that are relevant to pension plans have standards and codes of practice that apply to their members, e.g. Canadian Institute of Actuaries Standards of Practice, Canadian Association of Pension Supervisory Authorities (“CAPSA”) governance guidelines, Chartered Professional Accountants Canada (“CPA”) accounting and auditing standards and governance guidelines. The OEB should recognize the oversight roles of these regulators and professional bodies and, in meeting its own objectives, be informed of the results of any oversight provided by other bodies and where possible not duplicate the work of other regulators.

2.3 The governance framework of a pension plan should explain how the utility addresses governance matters including, but not limited to: fiduciary responsibility, governance objectives, roles and responsibilities, performance measures, knowledge and skills, plan design, funding policies, investment policies, risk management, oversight and compliance, transparency and accountability, code of conduct and conflict of interest, selection and oversight of internal and external service providers and the processes for governance review.

Information Requirements

2.4 Consideration should be given to whether a utility should be required to provide in its rates rebasing application a description of the governance framework it employs to govern its pension plans (both DB and DC plans).

2.5 Where a utility has provided such descriptions in a prior rates proceeding, consideration should be given to whether the utility should be required to provide an update regarding any changes in the applicable governance framework.

- 3 *Pension costs include rate-regulated activities only – Pension costs that do not relate to the rate-regulated business should be excluded in setting rates.*

Background Information

- 3.1 A utility may conduct activities and/or provide services that are outside those which are rate-regulated by the OEB. As well there are circumstances where services that are provided by utilities are not rate-regulated such as the provision of water-meter reading and billing services. Shareholders are to assume the liabilities and fund the costs of all such activities that are not rate-regulated and separate accounts are provided in the electricity and gas Uniform Systems of Accounts to capture all such revenues and related expenses so they can be tracked and verified as separate from the rate-regulated activities of the utility.
- 3.2 Employees may perform activities within the entity that relate to services that are both regulated and not rate-regulated. The pension costs associated with compensation of employees for services that are not rate-regulated are required to be excluded from costs that are included in determining rates.
- 3.3 Justification of the basis upon which pension costs are attributed to rate-regulated activities should consider the applicability of all key assumptions to the regulated and unregulated segments of the business and reflect any inherent differences in the underlying workforce. By way of example, this includes consideration of such matters as expected remaining years of service, expected salary increases, etc. The basis of attribution to the rate-regulated business should also provide suitable rationale for including costs arising from past service, particularly in cases where a new aspect of the business has recently become rate-regulated.
- 3.4 Where the structure of a regulated enterprise has changed, e.g., through the inclusion or removal of assets that are subject to rate-regulation or through merger or acquisition, the basis of attribution of pension costs may change.
- 3.5 There may be instances where there is a transfer of a group of employees into or out of a pension plan that is not due to a structural change in the enterprise. It is expected that the value of consideration given in the transfer will finance any deficit attributed to the transferees.
- 3.6 The OEB may find an actuarial assessment and valuation helpful at the trigger point of a structural change to determine the revised allowed portion, but this is not necessarily cost effective and therefore is generally not required.

Information Requirements

3.7 In its rates rebasing application, consideration should be given to whether a utility should be required to justify the basis upon which pension costs have been attributed to rate-regulated activities and differentiate the basis, to the extent practical, from how they are attributed to non-rate-regulated activities.

3.8 Where the structure of a regulated enterprise has changed, consideration should be given to whether a utility should be required to provide a review and analysis of the attribution of pension costs to the ongoing rate-regulated enterprise at the next proceeding in which it seeks to rebase rates. Such analysis includes identification of amounts not recovered or over-recovered in rates during the preceding rate period attributed to the structural change.

3.9 Consideration should be given to whether a utility should be required to disclose in its rates rebasing application any instance where a group of employees has transferred into or out of its pension plan and the amount of related consideration. In cases where the consideration given in the transfer does not finance any deficit, the implications will be considered by the OEB on a case-by-case basis consistent with the method by which amounts are included in rates.

3.10 Consideration should be given to whether a utility should maintain appropriate records to enable assessment of the reasonableness of the allocation of pension costs between rate-regulated and any non-rate-regulated activities.

4. Pension costs are reasonable – *Pension and related costs should be determined, where applicable, using actuarial methods and assumptions in line with professional standards and current best practice.*

Background Information

4.1 In general, assessing the fit with best practices, including the appropriateness of key assumptions used in the measurement of pension assets and/or obligations, is a means for the OEB to build confidence in the measurement of associated costs.

4.2 The actuarial assumptions used by a pension plan may be grouped into two categories: demographic assumptions and, economic (or financial) assumptions. The demographic assumptions reflect attributes of the employer's workforce and retirees and include, but are not limited to: the estimated average remaining years of service of the active employees, the estimated termination rate for employees, and mortality rates assumed for key groups of pensioners (e.g., male, female). The values assigned to the economic (or financial) assumptions include expectations associated with parameters external to the enterprise and include, but are not limited to: long-term interest rates used to set the discount rate, the

expected rate of return on the various categories of invested assets (where applicable), inflation and salary increase rates.

Information Requirements

- 4.3** In its rates rebasing application, consideration should be given to whether a utility should be required to provide the history of benefit plan changes (for example any improvements or reductions in benefits, and/or changes in employer/employee contribution levels) that have occurred over the 10 year period preceding a rates rebasing application with an explanation of the rationale for each change and its impact on cost.
- 4.4** Consideration should be given to whether a utility should be required to provide a breakdown of total compensation cost and pension cost showing separately the amount attributed to capital expenditures and the amount attributed to operating expenditures.
- 4.5** Consideration should be given to whether a utility should be required to provide pension costs separated between funded and unfunded pension plan costs.

Defined Benefit (“DB”) pension plans

- 4.6** Consideration should be given to whether a utility should be required to include in its rate rebasing application a description of the actuarial cost method used to determine the value of the underlying DB obligation (e.g., projected benefit method, entry age normal method) and the method used to determine amounts attributed to capital expenditures and amounts attributed to operating expenditures, for its DB pension plan(s). The utility should be required to explain any deviations from what is considered actuarial best practice along with an explanation of the implications of any such deviations.
- 4.7** Consideration should be given to whether a utility with DB pension plan(s) should be required to identify the key assumptions it has used in determining pension costs included in rate rebasing applications.
- 4.8** Consideration should be given to whether a utility should be required to provide the history of values for all key assumptions it used in DB calculations accompanied by explanations of any changes in the assumed values over the 10 year period preceding a rate rebasing application. In order to benchmark costs as a means of assessing their reasonableness, consideration should be given to whether a utility should be required to provide, for DB plans, external reference information as applicable regarding the range of acceptable values used by other plans for actuarial assumptions including

(but not limited to) mortality rates, discount rates, expected rates of return and salary increases.

- 4.9** Consideration should be given to whether the reference information required in 4.8 should describe the drivers that could influence the choice of assumption value for an individual DB plan from within the range of acceptable values. Consideration should be given to whether the utility should explain its choice of a particular value within the range of acceptable values, and provide cost sensitivity analysis associated with key assumption values.

Defined Contribution (“DC”) pension plans

(Includes OMERS which is a DB pension plan that is accounted for as a DC plan)

- 4.10** Where a DB plan is accounted for as a DC plan because it is a multi-employer plan (including jointly sponsored pension plan), consideration should be given to whether a utility should be required to provide evidence in rebasing applications concerning the funding status of the overall plan of which it is a member and evidence as to the steps being taken by the plan to address the deficiency or surplus and any expectations stated by the plan as to actions to be taken by member entities with respect to making up any deficiency or benefiting from any surplus. Consideration should be given to whether in its submission the utility should discuss any risks and potential implications for utility cost in the future arising from any deficiency (or surplus) in the multi-employer or jointly sponsored pension plan.

- 4.11** Consideration should be given to whether a utility should be required to disclose in its rates rebasing application whether the application includes any increases or decreases in contribution rates to multi-employer DB pension plans that are treated as DC plans, such as the OMERS plan. If an increase or decrease in contribution rates can be reasonably forecast, consideration should be given to whether a utility is required to provide such forecast (by years), documentation to support the forecast and state how the utility proposes to address the forecast amounts.

- 5. Pension cost information is reliable** - Amounts of pension costs included in rates should be based on and supported by amounts that have been provided and assessed by independent experts.

Background Information

- 5.1** General stated objective 4 requires the utility to demonstrate that its pension costs are reasonable. This is concerned with ensuring that the calculations and other information

provided by the utility is reliable so that it can be used with confidence by the rate-regulator for making decisions.

- 5.2 The OEB is authorized under governing legislation when establishing rates that are just and reasonable, to use any method that it considers appropriate that is consistent with its objectives. The OEB is informed by values included in a utility's audited financial statements, including the accounting cost and employer's funding contribution amount or direct payment, that are audited in relation to codified auditing standards. In addition, the accounting standards, funding regulations (where applicable) and actuarial standards provide for the determination of cost on the basis of methods that are systematic and rational. The result of using such values, at least as a starting point for consideration in setting rates, is increased confidence that the information is reliable. In addition, the OEB's Reporting and Record-keeping Requirements require periodic reporting including the provision to the OEB of audited financial statements. As such the OEB has the ability to seek reconciliation between amounts granted in rates proceedings and amounts ultimately reported in audited financial statements.
- 5.3 There are currently differences among the various accounting frameworks (e.g., International Financial Reporting Standards ("IFRS"), US Generally Accepted Accounting Principles ("US GAAP"), and Canadian Accounting Standards for Private Enterprises ("ASPE")) as to how pension costs are treated in the context of DB pension plans.
- 5.4 It may not be appropriate to enumerate the differing treatments among the various accounting frameworks in regulatory Information Requirements, particularly as they are changing over time. However, in reviewing rates applications in years soon after an accounting framework transition, particular attention should be made to the implications for pension costs in areas where there are known differences between the former accounting framework and the newly adopted accounting framework.

Information Requirements

- 5.5 Consideration should be given to whether a utility should be required in its rates rebasing application to provide a reconciliation of historical rate year pension cost information to pension cost information contained in audited financial statements for three years, explaining any differences.**
- 5.6 Consideration should be given to whether a utility should be required in rates rebasing applications to provide evidence, where the cost impacts would potentially be material in the year of rebasing or succeeding years, regarding the amount of pension cost differences arising because of any transition to a new accounting framework or funding contribution rules that it has undertaken or plans to take in the incentive regulation period. Consideration should be given to whether the evidence should state**

how any such differences are proposed to be dealt with in relation to utility customer rates and reference any previous related decisions of the OEB.

5.7 Consideration should be given to whether a utility should be required to provide in its rates rebasing application copies of all oversight reports provided to supervisory authorities with respect to any of its pension plans since its last rates rebasing. This includes, but is not limited to, actuarial funding valuation reports setting out the minimum and maximum funding contribution requirements. It includes communication with FSCO and CRA with respect to the plans.

5.8 In addition to information required in 5.7 above, consideration should be given to whether a utility should be required to provide in its rates rebasing application copies of all actuarial studies and reports, valuations or assessments provided to the utility since the last rebasing of rates with respect to its pension plans whether or not used in establishing the amounts included in the rates application or recorded in the audited financial statements.

5.9 If a utility applies to the OEB for rate rebasing and its most recent actuarial report is dated as at a date more than two years prior to the end of the most recent historical year included in the application, consideration should be given to whether the utility should be required to obtain an actuarial update with respect to the calculation of registered DB pension funding contribution values (excluding OMERS) and non-registered DB pension plan accounting costs included in the historical year financial statements.¹

6. *Pension costs are recovered over an appropriate time period* - Reasonable pension costs should be included in customer rates in time periods as close to the time periods to which they relate as is reasonable while recognizing the need for rate stability and predictability.

Background Information

6.1 The various accounting frameworks used in Canada, including IFRS, ASPE, and US GAAP specify whether, how, when, and over what time periods costs are to be recognized in the financial statements. Such accounting methods may or may not attribute costs to time periods that appropriately reflect the interests of utility customers.

6.2 For DB pension plans which are registered with FSCO and the CRA, the PBA and the Income Tax Act (the “ITA”) specify how the minimum and maximum cash contributions

¹ Pension fund regulations only require triennial valuations. Annual valuations are only required if funding levels are below 85%.

required to be remitted by the utility to the pension plan in respect of each year for plan funding purposes are to be calculated and attributed to time periods.

- 6.3 Pension costs are calculated differently depending on whether the employer plan is a DC plan or a DB plan. The complexity of calculation is much greater with DB plans.
- 6.4 For funded DB plans there are three pension values already determined for various purposes that the OEB could choose as the basis for inclusion of cost in customer rates. These are:
- a) The cash amount ultimately paid to or on behalf of beneficiaries (i.e., look-through the pension plan and establish the amount that is paid to the plan's beneficiaries in each period);
 - b) The amount contributed to the plan's fund to meet specified funding requirements (designed to ensure financial health of the plan over the long term); or
 - c) The amount specified by accounting standards for inclusion in audited financial statements (accrual basis of accounting).

For DB plans that are not funded, b) above is not applicable.

DC Pension Plans and DB Pension Plans that are Accounted for as DC Plans

- 6.5 In the case of DC pension plans, the calculation of the employer's contribution amount is relatively straightforward because the pension-related risk rests with the individual plan members and not the utility. For a DC pension plan, the employer's cash contribution for a year is dictated by the plan's contribution formula (e.g., a specified percentage of salary) and relates to benefits earned by employees during the current year.
- 6.6 Certain multi-employer DB pension plans, such as the OMERS plan, are treated by individual utilities as DC plans for accounting purposes. This is despite the fact that the utilities bear some of the pension-related risk. Accounting rules permit the plan to be accounted as a DC plan because an individual utility is unable to obtain adequate information to record costs on a DB basis. For such multi-employer DB pension plans, and all DC plans, the amount recognized for accounting purposes in a period consists of the contribution payable by the utility for service rendered during the period. The contribution payable to the plan for the period is recognized as an expense except to the extent that another accounting standard requires or permits their inclusion in the cost of an asset (e.g. property, plant and equipment or intangible asset).

Single Employer DB Plans

6.7 In the case of a single-employer DB pension plan, the calculation of costs for accounting and/or funding purposes is far more complex than the determination of the DC accounting cost because the utility bears the bulk of risk in meeting the obligations defined by its plans. Accounting principles require amounts associated with the benefits provided to employees to be recognized during the period in which the obligation to provide benefits to the employees arises, not when it is paid. Funding principles that are set out by the PBA determine the funding contributions that are required. Calculation of both amounts requires an actuarial valuation. The applicable standards set out the methods that must be used for DB pension plan funding and accounting valuations and how to set the assumptions, which include (as per 4.2 above):

- Economic (or financial) assumptions such as discount rates, expected returns on the various categories of invested assets (where applicable), inflation and salary increases; and
- Demographic assumptions such as mortality, retirement and termination rates.

6.8 The amount actually contributed to a registered DB pension plan in a given year will often differ substantially from the cost recognized for that year for accounting purposes and from the total amount paid directly to retirees and other plan beneficiaries. Regardless of this, determination of costs for accounting and funding purposes both require the setting of assumptions and actuarial valuations, and both result in the spreading of costs over a number of years.

6.9 Statutory funding requirements such as those defined by the PBA do not apply to non-registered supplemental DB pension plans (such as supplemental employee retirement pension plans (SERPs)). As a result, where such plans are unfunded, the utility's cash payment amounts are amounts paid to or on behalf of former employees, including retirees, and do not relate to the value of benefits earned by current employees of the utility. The accounting values do include the value of benefits earned by current employees.

6.10 If a utility considers that it faces undue financial hardship (or has earned an unexpected windfall) during the period of an incentive rates regime, there are a number of means that it can use to apply directly to the OEB to address the issue, or the OEB can use to address over earnings.

Information Requirements

6.11 For pension plans accounted for as DC plans, consideration should be given to whether a utility should be required to include in cost for purposes of determining rates the same cost value as is determined for accounting purposes.

- 6.12** For registered pension plans accounted for as DB plans, consideration should be given to whether a utility should be required to include in cost for the purpose of determining rates for the current period in its rates rebasing application the amount of the employer's Modified Funding Contributions remitted, or forecast to be remitted, in respect of the period.
- 6.13** As detailed in 1.10, consideration should be given to whether a utility should be required to identify and demonstrate in its rates rebasing application the impact and appropriateness of including amounts in excess of Modified Funding Contributions in rates for the current and future periods.
- 6.14** Pending the OEB's decision on disposition of any amount that is paid by a utility in excess of the Modified Funding Contribution amount, consideration should be given to whether the excess amount that is paid by a utility should be recorded in a separate deferral account, and attract a return.
- 6.15** Consideration should be given to whether a utility should be required to demonstrate how the DB plan amounts proposed for inclusion in determining rates were calculated, including how the amounts relate to PBA and FSCO minimum requirements and CRA maximum limits and the rationale for the amount chosen.
- 6.16** For non-registered plans that are DB plans, consideration should be given to whether a utility should be required to include in cost for the purpose of determining rates the same value as is determined for accounting purposes.
- 6.17** If the accounting framework that is used by a utility does not periodically reclassify to net income the component of pension costs that is recorded in OCI, consideration should be given to whether the utility should be required to record that amount in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the pension plan.
- 6.18** Consideration should be given to whether a utility with a pension plan (or plans) accounted for as DB plan(s) should be required to provide in its rates rebasing application a description for each plan and the method for including its costs in rates (including the basis for allocation between current period expenditures and capital expenditures).
- 6.19** Consideration should be given to whether a utility should file evidence to support any deviation from any requirements the OEB may establish with respect to points 6.11, 6.12 and 6.16 above.
- 6.20** Consideration should be given to whether a utility should be required to provide in its rates rebasing application evidence regarding the sensitivity of the pension cost

calculation to changes in the key assumptions used in calculating the amounts. Such evidence should include analysis and discussion of the potential impact of key assumptions (such as discount rates and mortality rates) on pension cost and customer rates.

Other Considerations

- 6.21** The impact of any policy change from an accounting or funding contribution based approach for determining pension cost for single-employer registered DB plans to a Modified Funding Contribution approach only affects a few utilities in a significant manner. Consideration should be given to whether a utility that is affected by this change should be required to have a deferral account to capture the difference caused by the transition so it can be considered for disposition in rates in future years.
- 6.22** Consideration should be given to whether a utility that changes its policy for determining the amount of pension cost included in rates should be required to disclose such fact in its rates rebasing application and to state the impact of such change. If the change also results in a material balance of unrecovered cost or an excess of cost previously recovered in rates, consideration should be given to whether a utility should be required to disclose such impact in its application and propose the means by which the OEB should authorize its disposition in rates.

3. Methods Identified for Recovering OPEB Costs and Information Requirements

3.1 Overview of Section

This Section presents proposed methods for recovering OPEB costs and related Information Requirements. The structure is similar to that of Section 2 (Pensions) with the exception of a new Sub-section (3.4) that relates to possible set-aside mechanisms that could be developed to support the use of accrual accounting cost for ratemaking purposes:

- **Section 3.2** sets out the method identified for recovering OPEB costs;
- **Section 3.3** provides the rationale for the identified method for recovering costs relating to OPEB plans. Other information about the results of KPMG’s work in gathering inputs relevant to identifying the appropriate methods for recovering OPEB costs has been included together with information on pension costs in Section 2.4. This information included a review of OPEB practices of rate-regulators in other jurisdictions, a review of the role of other regulatory authorities in Ontario with respect to OPEB matters, and the results of other relevant research;
- **Section 3.4** identifies alternatives for possible set-aside mechanisms that could be developed in order to provide customers with ‘value-for-money’ on the cash that is collected in advance of cash disbursements being made on OPEB obligations (i.e. excess recoveries). This Section is only relevant if accrual accounting cost is used to recover P&OPEB costs in rates;
- **Section 3.5** provides accounting guidance for OPEB costs based on ASC 980 (US GAAP); and
- **Section 3.6** lists the Information Requirements identified for costs relating to OPEB plans.

3.2 Methods Identified for Recovering OPEB Costs

Costs relating to OPEB plans can be split into two categories:

- a) Costs relating to OPEB plans that are accounted for as defined contribution plans (“DC”); and
- b) Costs relating to OPEB plans that are accounted for as defined benefit plans (“DB”). Within this category, the OPEB costs can be further analyzed as:
 - Costs relating to funded OPEB plans; and
 - Costs relating to unfunded OPEB plans.

KPMG has considered the nature of the different types of OPEB plans and has identified proposals for how costs could be recovered through rates. The OEB may wish to consider adopting the following methods for recovering costs relating to OPEB plans:

Category of OPEB costs	Methods for recovering OPEB costs in rates
OPEB plans that are accounted for as DC plans	Consideration should be given to whether a utility should include in cost for purposes of determining rates the same cost value as is determined for accounting purposes.
Funded OPEB plans that are accounted for as DB plans	<p>Two possible alternatives should be considered:</p> <p>a) Consideration should be given to whether a utility should include in cost for purposes of determining rates the same cost value as is determined for accounting purposes. Further, set-aside mechanisms could be developed to support the use of accrual accounting cost method for ratemaking purposes.</p> <p>If the accounting framework that is used by a utility does not periodically reclassify to net income the component of OPEB costs that is recorded in OCI, consideration should be given to whether a utility should be required to record that amount in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the OPEB plan.</p> <p>b) Consideration should be given to whether a utility should include in cost for purposes of determining rates an amount determined by the OEB to be its adjusted ‘pay-as-you-go’ cash payments.</p>
Unfunded OPEB plans that are accounted for as DB plans	<p>Two possible alternatives should be considered:</p> <p>a) Consideration should be given to whether a utility should include in cost for purposes of determining rates the same cost value as is determined for accounting purposes. Further, set-aside mechanisms could be developed to support the use of accrual accounting cost method for ratemaking purposes.</p> <p>If the accounting framework that is used by a utility does not periodically reclassify to net income the component of OPEB costs that is recorded in OCI, consideration should be given to whether a utility should be required to record that</p>

Category of OPEB costs	Methods for recovering OPEB costs in rates
	<p>amount in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the OPEB plan.</p> <p>b) Consideration should be given to whether a utility should include in cost for purposes of determining rates an amount determined by the OEB to be its adjusted ‘pay-as-you-go’ cash payments.</p>

The rationale for using the same method for recovering costs relating to OPEB plans that are accounted for as DB plans, irrespective of whether such plans are funded or unfunded, is detailed in Section 3.3 below. The methods for recovering OPEB costs that have been identified have also informed the specific Information Requirements that have been identified in Section 3.6.

3.3 Rationale for the Methods Identified for Recovering OPEB Costs

3.3.1 Overview of Section

This Section provides the rationale for the methods for recovering OPEB costs identified in Section 3.2 above. Section 3.3.2 provides a basic outline of how OPEB plans work. Included in Section 3.3.2 are references to Appendices A, B and C that present a more comprehensive explanation of how OPEB plans function and the different accounting treatment given to them under various accounting frameworks. Included in Section 2.3.3 above is a summary of the results of the review of regulatory practices for P&OPEB costs in other jurisdictions.

Against the backdrop of a basic outline of how OPEB plans work and the results of the review of the regulatory practices in other jurisdictions, Section 3.3.4 and Section 3.3.5 provide the rationale for the methods of recovering OPEB costs that have been identified.

3.3.2 Summary: OPEB Plans in Ontario and their Costing

3.3.2.1 Summary of Costing of OPEB Plans

OPEB plans provide post-employment benefits (other than pension) to employees. Benefits typically provided by regulated utilities through OPEB plans include certain post-employment medical, dental and life insurance benefits.

Typically, OPEB plans across North America are unfunded. The majority of the regulated utilities in Ontario currently recover OPEB costs using accrual accounting costs and a few regulated utilities use the ‘pay-as-you-go’ cash payments method. These two methods are defined as follows:

- Accrual accounting cost: this is the accrued cost determined by accounting rules (in accordance with a given accounting framework) and recognized in general purpose financial statements (ultimately split between capital expenditures, operating expenditures and OCI, where applicable); and
- ‘Pay-as-you-go’ cash payments: is equal to the cash amount ultimately paid to or on behalf of beneficiaries as benefits specified by the terms of the plan (i.e., look-through the OPEB plan and establish the amount that is paid to the plan’s beneficiaries in each period – i.e. the ‘pay-as-you-go’ cash payments method).

The *accrual accounting cost* and ‘pay-as-you-go’ cash payments methods often produce significantly different values of cost, one of which (typically the accounting cost) is then allocated in the books of account of the utility between capital expenditures, operating expenditures and OCI, where applicable. The differences between accrual accounting costs and ‘pay-as-you-go’ cash payments are significant because the ‘pay-as-you-go’ cash payments method does not include in the current period’s rates a cost estimate for the payments to be made in retirement from employee service rendered in the current period – these costs are only recognized when the cash payments are eventually made, in most instances, well into the future. As such, significant concerns have been raised regarding the use of the ‘pay-as-you-go’ cash payments method for including OPEB costs in the rates that are charged to customers.

On the other hand, a utility’s current customers could view the ‘pay-as-you-go’ method as more desirable due to the fact that the method only includes the cash costs that have actually been paid by a regulated entity during the period rather than current estimates of future payments; such estimates relate to long-dated obligations that are prone to significant estimation risk. Also, the linkage between the current period’s cash costs and the amount that is included in the current period’s rates is less complex to demonstrate in rate applications. That said, use of the normal ‘pay-as-you-go’ method would not allow utilities that have a finite life (such as certain nuclear power plants that are projected to shut-down in the medium-term) to fully recover projected future payments on OPEB obligations that extend well into the future.

There is no guarantee that one method will *always* result in higher (or lower) costs for a given period than the other. Depending on the age profile of a plan’s members, it could take a long period of time before the OPEB costs that have been accrued today are actually paid in the future. We note, merely for illustration purposes, the following analysis that was prepared by Great Lakes Power Transmission LP in their Interrogatory Responses dated October 14, 2014.¹

Non-Pension Benefit Plan	2010	2011	2012	2013	2014	2015	2016
Amounts included in rates							
OM&A	\$311,761	\$317,180	\$325,109	\$442,470	\$451,974	\$438,094	\$476,650
Capital expenditures	74,082	42,434	43,495	47,530	47,997	42,800	46,566
Sub-total	385,843	359,614	368,604	490,000	499,972	480,894	523,216
Paid Amounts	199,208	123,844	131,136	140,423	150,000	153,000	156,060
Net Excess amount included in rates greater/(lesser) than amounts actually paid	\$186,635	\$235,770	\$237,468	\$349,577	\$349,972	\$327,894	\$367,156

For Ontario Power Generation Inc., the following historical and forecast OPEB costs are detailed in Table 21 of the OEB’s Decision with Reasons dated November 20, 2014.²

\$million	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	Total 2008-13	2014 Plan	2015 Plan
Other Post-Employment Benefits									
4 Accrual Basis - recoverable in payment amounts	119.2	162.5	161.0	173.2	203.0	231.3		204.6	212.8
5 Cash Basis	44.2	43.1	43.4	48.4	57.9	61.2		89.6	95.8
6 Difference (4-5)	75.0	119.4	117.6	124.8	145.1	170.1	752.0	115.0	117.0

Further, the accrual accounting cost method has differences that relate to different accounting requirements in the various accounting frameworks currently available for use in Canada – see details of these differences as set out in the simplified example that is provided in Appendix G.

That said, despite these periodic differences in OPEB cost amounts, in the fullness of time, the cumulative cash payments for an OPEB plan is generally expected to equal that plan’s cumulative accrual accounting costs. This is true regardless of the accounting framework that is used by a regulated utility. As such, over time, a regulated utility that is allowed to also include in rates the

¹ Table 4-Staff-22 A: Great Lakes Power Transmission LP – Application for 2015 & 2016 Transmission Rates – Applicant Responses to Interrogatories from Board Staff, SEC, VECC and Energy Probe (EB-2014-0238), page 39.

² OEB Decision with Reasons, EB-2013-0321 dated November 20, 2014: Table 21, page 84.

amounts that are recorded in OCI would recover all its OPEB costs irrespective of the method that is used for setting rates.

As discussed in Section 2.3.3 and Appendix I of this report, some regulators allow the inclusion in cost for rate-setting purposes OPEB amounts equal to or based on accrual accounting cost while others allow OPEB amounts equal to or based on the ‘pay-as-you-go’ cash payments method, and not necessarily consistently among all utilities regulated by the same regulator. These practices are similar to the OEB’s current approach for including OPEB costs in the rates charged to customers.

3.3.2.2 Changes and Trends Affecting OPEB Plans

See Section 2.3.2.3 above.

3.3.3 Summary: Experiences and Practices in Other Jurisdictions

See Section 2.3.3 above.

3.3.4 Rationale for Accrual Accounting Costs Method vs. Pay-As-You-Go Cash Payments Method

As there is no regulatory funding requirement for OPEB plans, most regulated utilities in Ontario recover these OPEB costs based on the accrual accounting cost method. A small number of regulated utilities, however, recover OPEB costs based on the ‘pay-as-you-go’ cash payments method. As discussed earlier, the ‘pay-as-you-go’ cash payments method does not include in the current period’s rates a cost estimate for the payments to be made in retirement from employee service rendered in the current period. As such, significant concerns have been raised regarding the use of the ‘pay-as-you-go’ cash payments method for including OPEB costs in the rates that are charged to customers. As also indicated above however, a utility’s current customers could view the ‘pay-as-you-go’ method as more desirable due to the fact that the method only includes the cash costs that have actually been paid by a regulated entity during the period rather than current estimates of future payments; such estimates relate to long-dated obligations that are prone to significant estimation risk. That said, use of the normal ‘pay-as-you-go’ method would not allow utilities that have a finite life (such as certain nuclear power plants that are projected to shut-down in the medium-term) to fully recover projected future payments on OPEB obligations that extend well into the future.

Utilities could be required to use the accounting cost method for determining the OPEB cost to include in total cost for purposes of establishing rates. Set-aside mechanisms as detailed in Section

3.4 below could be developed to support the use of accrual accounting cost method for ratemaking purposes.

However, the different accounting frameworks treat similar components of OPEB costs differently. A significant difference relating to IFRS is that the component of OPEB costs that is recorded in OCI is not periodically reclassified to net income. In order to address this, consideration should be given to whether a utility should be required to record the amount that is required to be recorded in OCI in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the OPEB plan.

This has been included in the Information Requirements provided under general stated objective # 6, “*OPEB costs are recovered over an appropriate time period*”.

3.3.4.1 Pros and Cons of Using the Accounting Cost Method for OPEB Plans

The accounting cost method includes one major element of cost that is omitted from the ‘pay-as-you-go’ cash payments method, therefore making it more appropriate to use. The ‘pay-as-you-go’ cash payments method does not include in the current period’s rates a cost estimate for the obligation arising from employees’ service rendered in the current period; the cost is only payable in retirement. The ‘pay-as-you-go’ cash payments method only includes costs incurred on payments to retirees (i.e. post-employment or post-retirement). There is no amount included relating to the obligation that was generated during an employee’s working years. Thus, it introduces significant concerns about which generation of customers should actually pay for the costs. However, a utility’s current customers could view the ‘pay-as-you-go’ method as more desirable due to the fact that the method only includes the cash costs that have actually been paid by a regulated entity during the period rather than current estimates of future payments that will be made on long-dated obligations that are prone to significant estimation risk.

As indicated above, the accounting cost method has a disadvantage in that different accounting frameworks treat similar components of OPEB costs differently. A significant difference relating to IFRS is that the component of OPEB costs that is recorded in OCI is not periodically reclassified to net income. In order to address this issue, affected utilities could be permitted to propose to the OEB in their rate applications a systematic and rational method for including this component of OPEB costs in rates.

Most utilities have already adopted the accrual accounting cost method required by accounting standards for including OPEB plan costs in their rate applications. It should, however, be noted that using the accrual accounting cost method to include in rates OPEB costs creates the need to consider, identify and potentially establish alternatives for possible set-aside mechanisms in order to provide customers with ‘value-for-money’ on the cash that is collected by utilities in advance of cash

disbursements being made on the OPEB obligations (i.e. excess recoveries) – see additional discussion in Section 3.4 below.

As the amounts relating to OPEB costs are not as significant as those relating to pension costs, it could be argued from a materiality perspective that changing the current regulatory practice for the entire industry does not merit the benefits that would arise. As such, continuing with the current regulatory practice but supported by a possible set-aside mechanism, could be viewed by some as more desirable. A similar argument could also be made by those utilities that are currently using the ‘pay-as-you-go’ cash payments method.

3.3.5 Rationale for Adjusted Pay-As-You-Go Cash Payments Method vs. Accrual Accounting Costs Method

Use of the accrual accounting costs method to recover OPEB costs in rates charged to customers creates the possibility that a utility’s customers will be required to provide cash funding to a utility well in advance of the utility making payments on the related OPEB obligations. This could create significant concerns as measurement of the OPEB obligations and related costs for any given period is subject to significant estimation risk, albeit that a utility could take great care in establishing its best estimates for the costs relating to the period.

An alternative approach could be developed to recover OPEB costs in rates charged to customers based on actual ‘pay-as-you-go’ cash payments that are adjusted by an additional amount that the OEB establishes to be just and reasonable based on a utility’s facts and circumstances (i.e. “adjusted ‘pay-as-you-go’ cash payments method”). Under this method, ‘pay-as-you-go’ cash payments are the starting point (foundation) for determining the amount that is included in rates. However, such ‘pay-as-you-go’ cash payments are increased by an additional amount that is established by the OEB.

The OEB could adopt various approaches in order to determine the additional amount that is included in rates. For example, this could be annual amortization of the OPEB costs that are included in OCI using the average remaining service lives of active members that are participating in the plan (or a period up to 20 years) plus a portion of the OPEB costs that are determined using the accrual accounting costs method. Importantly, the key objective of whichever approach is adopted in order to determine the additional amount that is included in rates should be to ensure that there isn’t a build-up of OPEB costs that are not being included in rates over a reasonable period of time. See Section 3.5.2(a) for additional discussion on the accounting considerations relating to this alternative approach.

A utility’s current customers could view this method as more desirable than the accrual accounting costs method because this method uses as its starting point (and therefore is more closely aligned

with) the cash costs that have actually been paid by a regulated entity during the period rather than current estimates of long-dated future payments.

Utilities could be required to use the adjusted ‘pay-as-you-go’ cash payments method for determining the OPEB cost to include in total cost for purposes of establishing rates.

The adjusted ‘pay-as-you-go’ cash payments method has also been included in the Information Requirements provided under general stated objective # 6, “*OPEB costs are recovered over an appropriate time period*”.

3.3.5.1 Pros and Cons of Using the Adjusted ‘Pay-as-you-go’ Cash Payments Method for OPEB Plans

The adjusted ‘pay-as-you-go’ cash payments method has a distinct advantage over the normal ‘pay-as-you-go’ cash payments method because a utility is not necessarily prohibited by accounting standards from recognizing regulatory assets arising from the use of this method. This issue is discussed in detail in Section 3.5.2(a) below.

Further, the adjusted ‘pay-as-you-go’ cash payments method has the following advantages over the accrual accounting costs method:

1. The adjusted ‘pay-as-you-go’ cash payments are more understandable since the path from costs to amounts included in customer rates (audit trail) is less complex. It is therefore easier to explain to stakeholders in a rates proceeding. Specifically, estimation risk is reduced due to the fact that the amount that is included in the current period’s rates is based on actual cash payments expected to be made during the period. However, this risk is not fully eliminated because the OEB is still required to establish an additional amount that is just and reasonable based on a utility’s facts and circumstances – this would still involve judgment;
2. The adjusted ‘pay-as-you-go’ cash payments could result in greater comparability among utilities since costs in rates do not depend on the accounting standards that are used by a utility. The different accounting requirements among the various accounting standards (which result in different accounting cost) are eliminated as a source of variability. The adjusted ‘pay-as-you-go’ cash payments are also not subject to change when individual accounting standards evolve because its calculation is independent of these accounting standards; and
3. As the OEB determines the additional amount that is included in rates (i.e. the adjustment to the ‘pay-as-you-go’ cash payments), it is able to closely monitor the build-up of the additional amounts that are being collected in excess of actual cash payments. As such, the need to use possible set-aside mechanisms could be reduced or eliminated altogether.

However, as indicated above, the adjusted ‘pay-as-you-go’ cash payments method would require the OEB to determine the additional amount that would be included in rates. This is because of the

fact that the ‘pay-as-you-go’ cash payments method does not include in the current period’s rates a cost estimate for the obligation arising from employees service rendered in the current period; the cost is only payable in retirement. There is no amount included relating to the obligation that was generated during an employee’s working years. Great care would need to be exercised to ensure that the burden for this cost is not unjustly shifted to future generations of customers.

3.3.6 Previous Decisions by the OEB Regarding OPEB Plans

See Section 2.3.5 above.

3.4 Alternatives for Possible Set-Aside Mechanisms

3.4.1 Background

To date, the OEB has allowed certain regulated utilities to include accrual accounting costs for OPEB plans in rates. Depending on various factors, including whether the defined benefit plan is funded and its overall funded status, the OPEB costs determined by accrual accounting can be significantly different to the cash payments actually made by the regulated utility under the plan. In some cases, revenue can be collected from customers well in advance of the payments being made for the benefit obligations (i.e. “excess recoveries” can arise during the intervening period). It is, however, important to note that although the timing for the collection of cash may be significantly different to when payments are made for the benefit obligations, regulated utilities do not expect to recover the same cost twice.

There are no legal requirements for companies in Ontario, regulated or not, to set aside money to meet OPEB obligations. To date, the OEB has not specified any regulatory requirements relating to cash collected from customers in advance of the payment of OPEB obligations. However, issues regarding the establishment of segregated funds or irrevocable trusts for the excess cash that is collected by utilities that are regulated by the OEB are not new.

For example, in the case of OPG’s EB-2010-0008 application, OEB staff argued that if the accrual method was to continue to be used to include OPG’s OPEB costs in rates, the OEB should consider directing OPG to establish a segregated fund to deal with the differences between the amount collected in rates and the cash OPEB payments made by OPG. However, OPG doubted whether the OEB has jurisdiction to implement the proposal. In the end, the OEB’s finding was that:

“OPG correctly points out that there is currently no consistency amongst utilities in the use of either the cash or accrual method to setting P&OPEB expenses. Both methodologies have been approved by the Board. The Board in this case sees no compelling reason to change OPG’s existing approach of using the accrual method. Consistency in accounting treatment, in order to compare results year to year, is advantageous for purposes of assessing the level of costs for reasonableness. A consistent approach over time also ensures a greater level of fairness for ratepayers and the company.”¹

Another example is OPG’s rate application EB-2013-0321:

“Board staff supported use of the cash method for pensions and the accrual method for OPEBs, provided that OPG be directed to set up an irrevocable trust or fund for the recovery in excess of OPEB cash requirements. In the absence of a set-aside

¹ EB-2010-008 OEB Decision with Reasons (page 91)

mechanism, Board staff supported the use of the cash basis for both pensions and OPEBs.

Board staff submitted the Board could approve the accrual method for OPEB on the condition that OPG establishes a set-aside mechanism, such as an irrevocable trust or fund for OPEB, similar to what was referred to in the Federal Energy Regulatory Commission's Statement of Policy report PL93-1-000.92 Board staff also submitted that if the Board had any reservations about a fund or trust, the Board could limit recovery of OPEB expense as determined by the cash method, or OPG's out-of-pocket test period costs. OPG submitted that the Board has no jurisdiction to order OPG to set up an irrevocable trust or fund. OPG argued that the matter is complex and submitted that a segregated fund could be considered as part of a generic proceeding.

The Board will only allow OPG to recover its cash requirements for pensions and OPEBs in 2014 and 2015, approving a revenue requirement of \$836.9M for pension and OPEB.”¹

This report explores ways to provide customers with ‘value-for-money’ on the cash that is collected in advance of cash payments being made on OPEB obligations (i.e. excess recoveries), while at the same time safeguarding customers’ money that will be directed to settling the OPEB obligations in the future. If accrual accounting cost is used to include OPEB costs in rates, alternatives for possible set-aside mechanisms could also be developed in order to achieve this objective.

Use of ‘excess recoveries’ by regulated utilities

When cash is collected in rates in advance of benefit payments (i.e. as a result of accrual accounting costs being included in rates for unfunded OPEB plans), the cash is generally re-directed to fund capital or operational expenditures. Without these funds, some regulated utilities could have to seek additional external financing. By reducing the need for external financing in this way, a regulated utility may qualify for lower borrowing rates – where this is the case, customers benefit from such reduced borrowing rates indirectly through the calculation of the regulated utility’s return on debt. However, the benefit of the reduced borrowing costs (or income earned by the invested funds) is currently not being shared with customers in a direct manner. Rather, the shareholders of the regulated utility enjoy the direct financial benefits of the reduced borrowing costs (or income earned by the invested funds) and the customers benefit indirectly through the regulated utility’s reduced return on debt. Also, where a deemed capital structure of only debt and equity is used in setting customers’ rates, the ‘excess recoveries’ benefit the regulated utility’s shareholders as no allocation and cost is being assigned to this source of invested capital that is provided by the customers.

¹ EB-2013-0321 OEB Decision with Reasons (page 85-87)

3.4.2 Alternatives for Possible Set-Aside Mechanisms Identified

If accrual accounting cost is used to include OPEB costs in rates, the OEB could consider the following options as alternatives for possible set-aside mechanisms:

- a) Internally segregated accounts;
- b) Retirement compensation arrangements;
- c) Excess recoveries reduce rate-base; and
- d) Continue with the current practice, but record any excess recoveries in a tracking account that is monitored by the OEB.

Details of these options, as well as their pros and cons, are discussed in more detail below.

a) Internally segregated accounts

In its simplest form, the OEB could require that any excess recoveries be deposited in a separate bank and/or investment account. Such an account would not be legally set apart from the utility's other assets and would be available to general creditors. The account would be included in, and would be audited as part of, the regulated utility's general purpose financial statements. Any income and expenses, gains and losses accrued on the account could be for the benefit of customers, and the utility could be appropriately incentivized for managing the account.

Setting up the account and its day-to-day management, depending on the nature and size of the investments that are held in the account, would not involve significant cost. No significant additional income tax implications would arise.

This option, however, has the following disadvantages:

- 1) It does not necessarily result in optimization of a utility's source of funding. Indeed, despite a utility having what could be significant cash balances on its balance sheet, it may still have to raise additional debt to replace the cash that is set-aside in internally segregated accounts. Although a utility may be able to undertake various actions to mitigate the impact of this, it is possible that such debt funding might come at a price that is higher than the yield earned on the assets held in the segregated account. As such, 'value-for-money' might not be achieved;
- 2) Changing a utility's source of funding for its capital and/or operational requirements could also change its perceived investment and credit risk profile. This could potentially reduce the utility's credit rating and/or borrowing capacity (or increase its borrowing rates);
- 3) Given the sound financial standing of most regulated utilities in Ontario, and the fact that the OEB already has multiple sources of information to monitor the long-term financial viability of regulated utilities in relation to amounts collected from customers, requiring excess recoveries to be maintained in segregated accounts would seem to be an unnecessarily conservative measure;

- 4) Requiring regulated utilities to set up segregated accounts would seem to introduce inconsistency in how other long-term liabilities (including regulatory liabilities that by their very nature represent amounts due to be refunded to customers in the future) are dealt with in regulating a utility; and
- 5) There are no legal requirements for companies in Ontario, regulated or not, to set aside money to meet OPEB obligations. Introducing this requirement for regulated utilities would seem to add unnecessary complexity as well as regulatory and administrative burden.

b) Retirement compensation arrangements

Instead of an internally segregated account, the OEB could require that regulated utilities set apart the excess recoveries with a separate legal entity e.g. a trust. It is however important to note that any form of set-aside mechanism in which an employer makes contributions to a third party in connection with benefits for employees after their retirement is deemed to be a retirement compensation arrangement (“RCA”) under the *Income Tax Act (Canada)*, as long as contributions have been set apart from the company’s assets that are available to general creditors.¹ For this reason, any set-aside mechanism that is designed to operate in this manner would be subject to the RCA rules.

Under the RCA rules, the employer’s full contribution into the arrangement is deductible against the employer’s taxable income (provided the contribution is “reasonable”). This could result in tax savings of 26.5% of the contributed amount. Such tax savings could be passed on to the customers as the allowable cost relating to Payments in Lieu of Taxes (“PILs”) would reduce. Currently, the tax deduction is only available when the OPEB costs are paid.

An RCA is exempt from federal and provincial income taxes. However, 50% of the amount contributed to the RCA must be withheld and remitted as a refundable tax payment to the CRA. The CRA holds the tax that is withheld in this manner in a refundable tax account (“RTA”). The RTA held by the CRA earns no interest. In addition, the RCA is required to pay refundable tax equal to 50% of the investment income earned each year. When the RCA makes a distribution to cover, for example, the payment of P&OPEB costs, the RCA will receive a refund of tax equal to 50% of the distribution. Accordingly, in the fullness of time, the full refundable tax will be recovered.

The disadvantages of an RCA include:

- 1) All the disadvantages that have been identified for an internally segregated account (see above);
- 2) As 50% of all contributions and investment income is held in an interest-free RTA with the CRA, an RCA is not tax efficient and could result in the income earned on the funds

¹ The RCA provisions do not apply to registered plans, employee health and life trusts and other specifically defined arrangements under the *Income Tax Act (Canada)*.

provided by customers not matching the interest cost on the OPEB obligations. Such an outcome would, in the long-term, have negative implications to rates; and

- 3) The costs of setting up an RCA, its day-to-day management (depending on the nature, size and complexity of its investments), and annual financial reporting requirements (including audit) could be significant. For smaller OPEB plans, which would be the case for the majority of the regulated utilities, the set-up and ongoing administrative costs could substantially offset the benefits of such an RCA set-aside mechanism.

c) Excess recoveries reduce rate-base

An alternative to the two options discussed above is to require that excess recoveries be tracked in a separate regulatory account that is used to reduce rate-base. Our survey of experiences and practices in other jurisdictions indicated that this practice may have been used in the past by FERC for those utilities that had not set up irrevocable external trust funds for OPEB obligations – see Appendix J for details of FERC’s requirements to establish irrevocable external trust funds.

This option has the distinct advantage in that it does not involve significant additional costs to set up, it has no identifiable tax consequences and yet it provides customers with a specified, predictable and regulated return on any funding that they provide a regulated utility for costs that will be settled well into the future. ‘Value-for-money’ is clearly demonstrable.

This option allows regulated utilities to continue with the current practice of funding capital expenditure and working capital requirements (both are key components of rate-base) with the excess recoveries i.e. it would represent no change with regards to cash funding requirements. However, this option re-aligns the regulatory treatment so that it is consistent with rate-setting principles of providing shareholders with a return only on the operating assets that they have funded. By tracking the excess recoveries in a separate regulatory account that is used to reduce rate-base, the customers (and not the shareholders) benefit from any funding that they provide towards a regulated utility’s operating assets.

Compared to current practice, this option has the disadvantage that it reduces the shareholders’ base for earning a return. As such, shareholders could argue that this option reduces their return in a significant manner. Further, it could also be argued that the option changes a regulated utility’s investment and credit risk profile; this could potentially reduce the utility’s credit rating and/or borrowing capacity (or increase its borrowing rates).

d) Continue with the accrual accounting practice, but record any excess recoveries in a tracking account that is monitored by the OEB

Alternatively, the OEB could choose to continue with the practice of using the accrual accounting cost for ratemaking purposes, but also add a new requirement for any excess recoveries to be tracked in a separate regulatory account that would attract interest as specified by the OEB. To aide double entry book-keeping, the excess recoveries would have an ‘offsetting mirror account’. However the amount that is recorded in such an ‘offsetting mirror account’ would not attract interest. The net result is that only one of the two offsetting accounts would

attract interest. This accounting treatment is similar to the OEB’s past practice for Payments in Lieu of Taxes (“PILs”).

This option has the same advantages and disadvantages as the option discussed in Section 3.4.2(c) above (i.e. excess recoveries reduce rate-base) except that, in this case, rate-base is not reduced. Instead, the excess recoveries are recorded in a regulatory account which earns interest that could be different than the utility’s return on rate-base. As the interest rate on the regulatory account is de-coupled from the utility’s return on rate-base, the economic benefit that accrues to customers on the excess recoveries could also be different from the income earned by the shareholder in using the excess recoveries in the utility’s operations.

In summary:

The pros and cons for the four set-aside mechanisms identified above can be summarized as follows:

		Internally segregated accounts	RCA	Excess recoveries reduce rate-base	Current practice with a regulatory account
1.	‘Value-for-money’ on the cash funds provided by customers is clearly demonstrable as the economic benefits accruing to customers are linked with how a utility uses the excess recoveries in its business	✘	✘	✔	✔
2.	No significant adverse tax implications i.e. tax-efficient	✔	✘	✔	✔
3.	Set-up and ongoing administrative costs are not significant	✔	✘	✔	✔
4.	Tax deduction reduces PILs charged to customers	✘	✔	✘	✘

		Internally segregated accounts	RCA	Excess recoveries reduce rate-base	Current practice with a regulatory account
5.	Optimizes a utility's available source of funding	x	x	✓	✓
6.	Avoids changes to the perceived investment and credit risk profile of a utility	x	x	x	x
7.	Maintains the amount of rate-base and the return earned on rate-base at the same amount	✓	✓	x	✓
8.	Avoids a potentially unnecessary conservative measure	x	x	✓	✓
9.	Avoids inconsistency with the regulatory treatment of other long-term liabilities (excluding nuclear funds)	x	x	✓	✓
10.	Treats regulated utilities similarly to other non-regulated entities that provide the same benefits (i.e. not required to set-aside cash for non-registered P&OPEB obligations)	x	x	✓ – although non-regulated businesses do not use a rate base mechanism	✓ – although non-regulated businesses do not use regulatory accounts

Legend:

✓ = pro; and x = con

3.4.3 Transition to New Set-Aside Mechanism

If the OEB were to adopt either of the mechanisms for set-aside that are discussed in Section 3.4.2 above, it could choose to apply the new requirements retrospectively with catch-up adjustments for prior periods, prospectively with no adjustments for prior periods or on a phased-in basis.

a) Retrospective application with catch-up payments/ adjustments¹

Regulated utilities could be required to apply either of the two options discussed in Section 3.4.2(a) and Section 3.4.2(b) retrospectively with catch-up payments for any cumulative excess recoveries transferred into the relevant account on the date that the new requirements become effective. However, this approach could prove to be very punitive for those utilities that have collected significant excess recoveries. Such utilities would have to find funding for the catch-up payment, and could potentially have to raise new debt.

Under the third option that is discussed in Section 3.4.2(c), the catch-up adjustment could be required to be made against opening rate base for the period that the new requirements become effective. Again, this approach could prove to be very punitive for those utilities that have collected significant excess recoveries as their rate base (and return for shareholders' investments) could be reduced significantly.

In practice, it is potentially much easier to apply the new requirements retrospectively for the option discussed in Section 3.4.2(d) than doing so for the other options. However, again, depending on the interest rate that is set for the account, retrospective application could prove to be punitive for the shareholders of those utilities that have collected significant excess recoveries in the past.

It could be argued that retrospective application with catch-up payments/ adjustments such as this represents retrospective rate-making. This could have significant negative consequences for the industry (including issues relating to the legality of such a move).

Excess recoveries after the new requirements become effective would be transferred into the relevant account.

¹ It is possible that legal arguments could be made that this would represent retrospective ratemaking, and concerns could be raised about this. However, such a legal assessment is outside the scope of this report; this issue has not been considered further in this report.

b) Prospective application with no catch-up payments/ adjustments

Although prospective application of either of the four options discussed in Section 3.4.2 would probably represent the most pragmatic approach for transitioning to the new requirements as the regulated utilities would not be subjected to an immediate cash squeeze and would not create legal issues related to retrospective ratemaking, this approach would likely still require detailed tracking. It would seem improbable that the OEB will not hold the regulated utilities (or customers) responsible for the excess (under) recoveries that have occurred to date. Regulated utilities would have to determine whether costs are being paid out of funds that were previously over/ (under) collected under the old requirements or they are being paid from collections received under the new approach. To reduce implementation effort, methods such as ‘first-in, first-out’ could be used to reduce the need for detailed tracking (i.e. all payments made immediately after transition to the new requirements could be drawn from the previous excess recoveries until such previous excess recoveries are fully utilized).

Excess recoveries after the new requirements become effective would be transferred into the relevant account.

c) Phased-in approach

Another approach that could be adopted to transition to the new requirements is to phase in the new requirements over a period of time. Although such an approach would not eliminate the need to eventually transition to the new requirements using either of the two approaches discussed above, a phased-in approach has the distinct advantage of providing regulated utilities with an opportunity to develop detailed understanding of the new requirements as well as provide relief as they adapt their sources of funding accordingly. In this way, a funding shock to the industry is averted.

3.5 Accounting Guidance for OPEB Costs based on ASC 980 (US GAAP)

The accounting guidance that is set out in this Section of the report specifically relates to those regulated entities that prepare their general purpose financial statements in accordance with US GAAP. The intent of this section is to provide guidance on the impact on a utility's financial reporting of using the 'pay-as-you-go' method for setting rates and to determine under what conditions accounting standards could prohibit the recognition of regulatory assets if a method other than the accrual accounting cost is used to recover OPEB costs in rates.

It is important to note that regulated entities that prepare their general purpose financial statements in accordance with legacy Canadian GAAP and ASPE, as well as those regulated entities that are eligible to elect to apply the requirements of IFRS 14 and elected to do so when they adopted IFRS (see Section 1.5 of Appendix C below), generally all recognize regulatory deferral and variance accounts in accordance with the US GAAP accounting principles set out in ASC 980. As such, in most instances, this accounting guidance is also equally applicable to the regulated entities that report under these three accounting frameworks.

3.5.1 General Guidance

See Section 2.4.1 above.

3.5.2 Guidance for OPEB Costs

Like regulatory accounting guidance for pension costs, regulatory assets for OPEB costs are only recognized if it is probable that future revenue in an amount at least equal to the deferred cost will be recovered in rates. However, unlike the regulatory accounting guidance for pension costs, ASC 980-715 includes significant additional restrictions on the recognition of regulatory assets relating to OPEB costs.

These restrictions, which also include limits on the period for deferring the OPEB costs, seemingly have little logical basis if they are not read and considered in the context of the significant cost deferral issues that arose in the late 1980s as a result of phase-in plans and nuclear plant costs. The restrictions were introduced in 1992 when US GAAP for OPEB costs changed from 'pay-as-you-go' to accrual accounting, and concern at the time was that the cumulative difference between accrual accounting and OPEB costs included in rates may continue to increase for many years. However, if the specified criteria is met (see further discussion below), regulatory balances relating to OPEB costs are required to be recognized.

It should also be noted that the restrictions were developed at a time when the requirement was to move from ‘pay-as-you-go’ to accrual accounting; the restrictions did not specifically consider the case where a regulated entity moves from accrual accounting to ‘pay-as-you-go’. As such judgment would be required if this is the case.

The restrictions, which continue to exist under US GAAP today, are set out below. Note that regulatory assets for OPEB costs are only recognized if all the criteria specified in the restrictions below are met, subject also to it being probable that future revenue in an amount at least equal to the deferred cost will be recovered in rates. If an entity does not initially meet all the criteria but meets the criteria in a subsequent period, then a regulatory asset related to OPEB costs is recognized in the period all the criteria are met.

a) Use of ‘pay-as-you-go’ basis to recover OPEB costs

ASC 980-715-25-4 states that *“For continuing postretirement benefit plans, a regulatory asset related to Subtopic 715-60 costs shall not be recorded if the regulator continues to include other postretirement benefit costs in rates on a pay-as-you-go basis.”*

US GAAP does not define what is meant by the ‘pay-as-you-go’ basis of including benefit costs in rates. However, the background information that supported the consensus to include the restrictions indicates that *“Before the adoption of Statement 106, most employers, including rate-regulated enterprises, accounted for OPEB costs on a pay-as-you-go (cash) basis.”* As such, ‘pay-as-you-go’ is generally understood to have the same meaning as the following definition contained in Statement No. 45 of the United States Governmental Accounting Standards Board, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pension*:

‘Pay-as-you-go’ is a method of financing an OPEB plan under which the contributions to the plan are generally made at about the same time and in about the same amount as benefit payments and expenses becoming due.

If OPEB costs are recovered in rates based on a method that falls within this definition of ‘pay-as-you-go’ basis of recovery, then regulatory assets would not be recognized under US GAAP; any previously recognized regulatory assets would have to be written-off in the financial statements. However, other methods of recovering OPEB costs would seem not to conflict with this specific requirement and regulatory assets would be recognized, subject to the additional criteria set out in Section 3.5.2(b) and Section 3.5.2(c) below also being met. For example, as also described in Section 3.5.4 below, the following method of recovering OPEB costs would seem to result in OPEB costs being recovered on a basis that is other than the ‘pay-as-you-go’ method that is contemplated and restricted by ASC 980-715-25-4. Variations to the mechanics of this method are possible:

- a) For current and future rate-setting periods, include the cash amount ultimately paid to or on behalf of beneficiaries as benefits specified by the terms of the OPEB plan (i.e. the ‘pay-as-you-go’ cash payments method), minus;
- b) Annual amortization of the amount that was previously collected from customers based on accrual accounting costs (i.e. prior to the change-over to this new method of recovering OPEB costs – see details in Section 3.5.4 below) using the average remaining service lives of active members that are participating in the plan (or a period up to 20 years), plus;
- c) An additional amount that the regulator could determine. For example, this could be annual amortization of the OPEB costs that are included in OCI using the average remaining service lives of active members that are participating in the plan (or a period up to 20 years) plus a portion of the OPEB costs that are determined using the accrual accounting costs method. The key objective for this item would be to ensure that there isn’t a build-up of OPEB costs that are not being included in rates over a reasonable period of time.

As items b) and c) above result in OPEB costs being recovered on a basis that is other than the ‘pay-as-you-go’ method that is contemplated and restricted by ASC 980-715-25-4, it would seem that this method would still permit the recognition of regulatory assets relating to OPEB costs. However, this all requires key judgment by a utility’s management when they prepare the utility’s financial statements, and external auditors opine on such judgments based on materiality and impact to the overall presentation of the financial statements.

The following issues are also important to note:

- i) The restriction for the ‘pay-as-you-go’ method is only with regards to the recognition of regulatory assets. Regulatory liabilities for OPEB costs should be recognized irrespective of the method used for including such OPEB costs in rates – see further details in Section 3.5.4 below for discussion on the transitional regulatory liability relating to a change from accrual accounting to the ‘pay-as-you-go’ method;
- ii) The language used in this restriction (i.e. “For continuing postretirement benefit plans”) makes it clear that the restriction was intended to apply to those regulated entities that continued to recover OPEB costs on a ‘pay-as-you-go’ basis instead of switching to accrual accounting when US GAAP changed. The restriction was not necessarily designed to apply when the reverse situation exists and a regulated entity switches from accrual accounting to the ‘pay-as-you-go’ basis. As such, careful judgment by the utilities and their auditors is required, particularly if a transitional regulatory liability exists – see Section 3.5.4 below for further details on this issue; and
- iii) Canadian regulated entities previously recorded regulatory assets and liabilities under legacy Canadian GAAP by referring to ASC 980 for guidance. However, some Canadian regulated entities did not necessarily apply all the requirements and restrictions contained in ASC 980 when accounting for OPEB costs. As such, some Canadian regulated entities recognized regulatory assets for OPEB costs under legacy Canadian GAAP even if they recovered the OPEB costs on a ‘pay-as-you-go’ basis. As a result of the new IFRS accounting guidance for regulatory balances, some of these regulated entities may be able

to continue this practice under IFRS. However, those regulated entities that have transitioned to US GAAP were not able to continue this practice and had to derecognize the regulatory assets. For example, when Fortis Alberta Inc. transitioned from legacy Canadian GAAP to US GAAP in 2012, it derecognized the regulatory assets for OPEB costs that are being recovered on a ‘pay-as-you-go’ basis. As such, for Fortis Alberta Inc., OPEB costs are now recognized in net income and OCI without any amounts being deferred as regulatory assets (thereby immediately impacting the carrying amount of retained earnings and AOCI).

b) Limits on the period for deferring OPEB costs

As indicated above, ASC 980-715-25-5 (see details in Section 1.4 of Appendix K) also includes restrictions that limit the period of time that any recognized regulatory asset for OPEB costs can be deferred. Although the time limits were specifically designed to address transitional issues that existed in 1992 when US GAAP for OPEB costs changed from ‘pay-as-you-go’ to accrual accounting and, as such, some of the language used for the time limits would not be applicable to an entity that has been applying US GAAP for some time, it would seem that the key issues that are intended to be addressed by these time limits are:

- i) Concern at the time was that the cumulative difference between accrual accounting and OPEB costs included in rates may continue to increase for many years. As such, ASC 980-715 states that the combined deferral-recovery period authorized by the regulator should not exceed approximately 20 years from the date of adoption of Sub-Topic 715-60.
- ii) That the recovery of the regulatory asset for OPEB costs should not be ‘back-end loaded’ as significant risk would arise from this. ASC 980-715-25-5(b)(4) states that, for regulatory assets to be recognized for OPEB costs, rate increases for a future year should be no greater than the percentage increase in an immediately preceding year. However, recovery of the OPEB regulatory asset in rates on a straight-line basis would meet this criterion.

As the requirements for entities that have already been reporting under US GAAP are not very clear, one possible view is that the time limits are only applicable to those regulatory assets that would have been recognized when US GAAP for OPEB costs changed from ‘pay-as-you-go’ to accrual accounting in 1992 (i.e. a transition issue only). Such a view would mean that regulated entities would be free to recognize regulatory assets for differences in OPEB costs subsequent to the adoption of ASC 715-60. However, such a view would ignore the rationale for having the time limits.

An alternative view would be to give weight to the reasons why the time limits were established in the first place, and adopt similar time limits for the differences in OPEB costs subsequent to the adoption of ASC 715-60. Continuing to apply the time limits by analogy in this way would continue to reduce risk as was originally intended when the time limits were established. Adopting such a pragmatic view in the absence of clear guidance in ASC 980 would result in regulatory assets for OPEB costs being recognized as long as (i) the maximum period used for recovering the deferred OPEB costs respects the period of approximately 20 years from the date

that Sub-Topic 715-60 is first applied by the entity; (ii) the deferred OPEB costs are recovered on a straight-line basis, or another method that does not result in significant ‘back-end loading’ of OPEB costs; and (iii) the other criteria applicable to regulatory assets for OPEB costs are met – see Section 3.5.2(a) above and Section 3.5.2(c) below.

c) Rate Order or Statement of Policy

An additional requirement for the recognition of regulatory assets relating to OPEB costs is that the regulator needs to have issued a rate order or issued a policy statement or a generic order applicable to entities within the regulator’s jurisdiction that allows both for the deferral of OPEB costs and for the subsequent inclusion of those deferred costs in the entity’s rates.

As such, subject to the other criteria applicable to regulatory assets for OPEB costs being met, the OEB can directly impact whether a regulated entity recognizes regulatory assets for OPEB costs. In the US, in some instances, FERC has issued a general policy statement or regulatory accounting guidance for the entities that it regulates – see Appendix J of this report. OEB could also issue similar general policy statements or regulatory accounting guidance. Alternatively, the OEB could deal with this issue as part of a specific rate order for the affected regulated entities. However, the issuance of guidance by the OEB would make the process more efficient.

Impact of OPEB amounts recognized in OCI

The rationale for recognizing regulatory assets for pension amounts otherwise recorded in OCI is detailed in Section 2.4.2 above. Similar accounting considerations would also apply for the OPEB costs that are otherwise recorded in OCI. Therefore, if it is concluded that a regulated entity meets the criteria to recognize regulatory assets for OPEB costs, then regulatory assets are also recognized for the related amounts in OCI. Conversely, if it does not meet the criteria (e.g. because it only recovers OPEB costs on a ‘pay-as-you-go’ basis), then regulatory assets would also not be recognized for the amounts in OCI.

Section 1.2 and Section 1.3 of Appendix I illustrate the accounting practices by those entities that recognize regulatory assets for OPEB costs and those that do not, respectively.

3.5.3 Illustrative impact of recovering P&OPEB costs on the 'pay-as-you-go' basis

As detailed in Section 3.5.2 above, including OPEB costs in rates strictly on the 'pay-as-you-go' basis as contemplated and restricted by ASC 980-715-25-4 disqualifies a regulated entity from recognizing regulatory assets on the OPEB costs. However, such a regulated entity could still recognize regulatory assets for its pension costs (see Section 2.4.2). This difference in accounting treatment could have a significant impact on the net income and shareholders' equity that is reported by the regulated entity - this is illustrated in the example set out below:

	Amounts before P&OPEB Costs \$M	P&OPEB Costs \$M	A Amounts after P&OPEB Costs \$M	Regulatory Asset for Pension Costs \$M	B Amounts After Regulatory Asset for Pension Costs \$M	Regulatory Asset for OPEB Costs \$M	C Amounts After Regulatory Assets for P&OPEB Costs \$M
Net income before P&OPEB expense	135	-	135	-	135	-	135
P&OPEB expense*	-	(767)	(767)	505	(262)	262	-
- Pension costs	-	(505)	(505)	505	-	-	-
- OPEB costs	-	(262)	(262)	-	(262)	262	-
Net increase in retained income	135	(767)	(632)	505	(127)	262	135
OCI for the year before actuarial gains and losses	295	-	295	-	295	-	295
Actuarial gains and losses for P&OPEB*	-	1,393	1,393	(814)	579	(579)	-
- Pension	-	814	814	(814)	-	-	-
- OPEB	-	579	579	-	579	(579)	-
Net increase in OCI	295	1,393	1,688	(814)	874	(579)	295
Total increase in shareholders' equity	430	626	1,056	(309)	747	(317)	430

* - this illustrative example excludes impacts from taxation and from amortization of actuarial gains and losses.

These are the amounts that would be reported by:

A - a non-regulated entity.

B - the same entity if it is regulated and recovers OPEB costs on a 'pay-as-you-go' basis.

C - the same entity if it is regulated and recovers OPEB costs on a basis that is not 'pay-as-you-go'.

3.5.4 Transitional regulatory liabilities upon switching from accrual accounting to 'pay-as-you-go'

On a cumulative basis to date, it is unlikely that utilities that include OPEB costs in rates based on accrual accounting costs would have paid benefits that exceed the amounts that have been collected from customers. If the OEB were to switch to 'pay-as-you-go' cash payments method for ratemaking purposes, it would be important to also consider how the OEB would treat the cumulative amount that regulated entities have already collected from customers in the rates charged so far. Due to the fact that it would be a windfall for regulated entities and, on the other hand, ratepayers would pay for the same cost twice, it would seem improbable that the OEB will not hold the regulated entities responsible for the amounts collected to date and yet also allow the full amount of the OPEB costs to be recovered in future rates when the costs are eventually paid¹. Half of the stakeholders that provided initial written submissions to the proposed public Consultation specifically agreed that customers, utilities, shareholders and employees should be kept whole if any changes were to be made to the method for recovering P&OPEB costs.

As such, it would seem likely that regulated entities would have to record transitional regulatory liabilities if the basis of recovery were to be switched from accrual accounting to 'pay-as-you-go' cash payment method. The regulatory liabilities would have to be recognized as the restriction for recognizing differences relating to OPEB costs only applies with regards to regulatory assets, not regulatory liabilities. However, if the OEB were to decide to not hold regulated entities responsible for the amounts collected to date and, at the same time, allow the OPEB costs to be recovered in full when the costs are eventually paid in the future, the regulated entities would clearly benefit from double collection of the same cost (i.e. from the amount recovered from customers in rates so far, and again when the costs are eventually paid on the 'pay-as-you-go' cash payments basis that would be implemented after the change-over).

By concurrently having such transitional regulatory liabilities, this would raise the question whether the regulated entities would still be considered to be recovering costs on the same 'pay-as-you-go' basis that is contemplated and restricted by ASC 980-715-25-4. The restriction in ASC 980-715-25-4 clearly did not envisage a situation in which a regulated entity initially recovered OPEB costs based on accrual accounting and, after having collected significant amounts (which would be represented by the regulatory liabilities), subsequently switched to the 'pay-as-you-go' basis. This issue would require key judgment, and it would be critical to understand how the OEB would require disposition of such transitional regulatory liabilities. For example, if the period of refund is very short (or the OEB requires immediate refund) then it is more likely that the restriction in ASC 980-715-25-4 would prevent regulated entities from recording regulatory assets for the difference

¹ It is possible that legal arguments could be made that this would represent retrospective ratemaking, and concerns could be raised about this. However, such a legal assessment is beyond the scope of this report; this issue has not been considered further in this report.

between net periodic OPEB cost as defined in Sub-Topic 715-60 and the amount of OPEB costs considered for rate-making purposes on the ‘pay-as-you-go’ basis. Conversely, if the period of the refund closely matches the period over which the OPEB costs will be recovered in rates on the ‘pay-as-you-go’ basis, and there is no significant build-up of OPEB costs that are not being included in rates over a reasonable period of time, it is possible that such a method would not be considered to be based on the same ‘pay-as-you-go’ basis as that contemplated and restricted by ASC 980-715-25-4. However, this would all require careful judgment by the regulated utility’s management and the auditors that opine on its financial statements based on each specific fact pattern.

3.5.5 Actions that the OEB could take to influence the recognition of regulatory assets for OPEB costs

As the regulator for utilities in Ontario, certain actions that are taken by the OEB can influence whether regulated entities will recognize regulatory assets relating to OPEB costs. These regulatory actions could include:

- a) As detailed in Section 2.4.1, before an incurred cost can be recognized as a regulatory asset, it should be probable that the incurred cost will be recovered in future rates. The criteria for ‘probable’ is judgmental. Clearly, any guidance that is issued by the OEB that provides additional assurance that OPEB costs will be included in future rates would be of great help to the regulated entities. Such additional guidance need not limit the OEB from reviewing the reasonableness of the elements of OPEB costs included in future rate proceedings, but potentially could greatly reduce uncertainty regarding future recovery of OPEB costs;
- b) Like FERC, the OEB could issue general policy guidance with respect to the future regulatory treatment of OPEB costs that are recognized in OCI – see Section 2.4.2;
- c) If a basis other than strictly ‘pay-as-you-go’ basis is used to recover OPEB costs, the OEB could influence the recognition of regulatory assets for OPEB costs by adopting a pragmatic view, in the absence of clear guidance in ASC 980. This could include the following guidance by analogy (i) setting the maximum period used for recovering the deferred OPEB costs on a basis that is respectful of the period of approximately 20 years from the date that Sub-Topic 715-60 is first applied by the entity; and (ii) requiring the deferred OPEB costs to be recovered on a straight-line basis, or another method that does not result in significant ‘back-end loading’ of the OPEB costs – see Section 3.5.2;
- d) Like FERC, if a basis other than strictly ‘pay-as-you-go’ basis as contemplated and restricted by ASC 980-715-25-4 is used to recover OPEB costs, the OEB could issue rate orders or a policy statement or a generic order applicable to regulated entities that allows both for the deferral of OPEB costs and for the subsequent inclusion of those deferred costs in the entity’s rates – see Section 3.5.2; or

- e) If the OEB were to switch the method of recovering OPEB costs from accrual accounting costs method to ‘pay-as-you-go’ cash payments method, the OEB could clearly specify how the transitional regulatory liabilities that would arise would be disposed. If the period of any refund to customers closely matches the period over which the OPEB costs will be recovered in rates on the ‘pay-as-you-go’ basis, and there is no significant build-up of OPEB costs that are not being included in rates over a reasonable period of time, it is possible that such a method would not be considered to be based on the same ‘pay-as-you-go’ basis as contemplated and restricted by ASC 980-715-25-4. However, this would require careful judgment based on each specific fact pattern – see Section 3.5.4.

3.6 Information Requirements Identified (with supplementary explanatory statements)

KPMG has identified the following Information Requirements that would support the regulatory review of OPEB costs. In some instances, the Information Requirements represent documentation of existing requirements that have not been previously part of the OEB’s regulatory requirements. For example, some individual utilities may already have been required to submit some of the Information Requirements as part of their separate rate applications. As such, some of the Information Requirements are documentation of existing practice. However, in other instances, the Information Requirements do result in new regulatory filing and reporting requirements. The impact may be significant; details of the extent of the changes and impact of those changes can only be determined on a case by case basis.

Also included in the Information Requirements are information disclosure matters that, if adopted by the OEB, would allow the OEB, intervenors and other interested parties to ensure that sufficient information is made available in rate setting proceedings. The specific circumstances include: situations where non-utility employees are members of pension plans that also include utility employees; utility re-organizations and plan restructurings; and, the effects of changes by a utility in its choice of accounting framework (e.g., IFRS vs US GAAP, etc).

The proposed public consultation may wish to consider some or all of these Information Requirements.

The Information Requirements may be summarized into six categories or general stated objectives as detailed below. If adopted, the OEB may find it useful to monitor and evolve the Information Requirements over time to ensure that they remain relevant and effective and to adapt to changes in legal, accounting or other regulatory requirements.

*Note: Following each general stated objective below are indented numbered paragraphs. The paragraphs in **boldface font** are proposed Information Requirements for utilities to submit to the OEB. Paragraphs that are not in boldface font are background information and explanatory statements.*

- 1. OPEB costs provide value for money** - As part of competitive compensation costs, customers should expect to pay OPEB costs that provide value for money and are in line with comparative benchmarks.

Background Information

- 1.1 OPEB plans are provided to employees as components of employee compensation plans. Compensation plans should be designed to allow the employer to attract and retain appropriately skilled staff. At the same time, utilities should not expect to pass on to customers excess costs of providing benefits that are not in line with sector practice or to pass on to customers excess costs that could be avoided by efficient management actions.
- 1.2 The OEB's mandate includes ensuring customers receive value for money for utility spending on OPEB plans. OPEB costs are components of overall compensation cost and, as such, it is not reasonable to assess value for money for OPEB costs in isolation.
- 1.3 OPEB plan administration costs (such as fees paid to actuaries) and, for funded plans, asset management costs (such as the fees paid to investment advisors) may be paid directly by utilities or from the benefit plan.
- 1.4 DB OPEB amounts in respect of the employer's accrual accounting cost represent the direct costs attributable to a given period.

Information Requirements

- 1.5 In order to ensure utilities have appropriate incentive to manage their OPEB costs, consideration should be given to whether a utility should demonstrate that its total compensation costs and compensation strategy are in line with sector practice. This can be demonstrated through benchmarking. Utilities may find cost-effective ways to obtain appropriate comparators and cost benchmark information through participation in industry associations.**
- 1.6 Consideration should be given to whether all administration costs and OPEB plan asset management costs should be provided as part of rate rebasing applications. All such costs could be categorized as OPEB costs regardless of whether they are paid directly by the utility or from the defined benefit plan.**
- 1.7 Consideration should be given to whether a utility should monitor its compensation cost benchmark performance over time and its cost performance to demonstrate continuous improvement and that it is delivering value for money for customers.**

- 1.8 Where a utility provides enhanced benefits under early retirement or other severance arrangements, consideration should be given to whether the utility should be required to demonstrate the value of the enhancements and impact on customers in its rates rebasing application.**
 - 1.9 Consideration should be given to whether a utility should be required to provide evidence in its rates rebasing application that identifies separately the amount of cost arising from any plan directed to special categories of employees such as a supplemental plan(s) for executives. Such evidence should identify the amount contributed by employees to any such plan(s) and describe the basis of determining the amount included in rates (i.e., accrual accounting, funding contribution, pay-as-you-go cash payment or other methods as may have been approved by the OEB).**
 - 1.10 Consideration should be given to whether a utility should be required to provide evidence in its rates rebasing application that identifies separately the amount of cost arising from any changes made to OPEB plans that reference employee services rendered in the past.**
- 2. *Governance for OPEB plans reflects best practices – OPEB plans should be subject to a high standard of governance addressing oversight, investment management, and administration.***

Background Information

- 2.1 The objective seeks to provide increased confidence that customers are not bearing the costs of poor OPEB cost management and that OPEB plan risks are appropriately addressed.
- 2.2 Professional bodies that are relevant to OPEB plans have standards and codes of practice that apply to their members, e.g. Canadian Institute of Actuaries Standards of Practice, Chartered Professional Accountants Canada (“CPA”) accounting and auditing standards and governance guidelines. The OEB should recognize the oversight roles of these professional bodies and, in meeting its own objectives, be informed of the results of any oversight provided by other bodies and where possible not duplicate their work.
- 2.3 The governance framework of an OPEB plan should explain how the utility addresses governance matters including, but not limited to: fiduciary responsibility, governance objectives, roles and responsibilities, performance measures, knowledge and skills, plan design, risk management, oversight and compliance, transparency and accountability, code of conduct and conflict of interest, selection and oversight of internal and external service providers and the processes for governance review.

Information Requirements

- 2.4 Consideration should be given to whether a utility should be required to provide in its rates rebasing application a description of the governance framework it employs to govern its OPEB plans (both DB and DC plans whether funded or unfunded).
 - 2.5 Where a utility has provided such descriptions in a prior rates proceeding, consideration should be given to whether a utility should be required to provide an update regarding any changes in the applicable governance framework.
3. *OPEB costs include rate-regulated activities only – OPEB costs that do not relate to the rate-regulated business should be excluded in setting rates.*

Background Information

- 3.1 A utility may conduct activities and/or provide services that are outside those which are rate-regulated by the OEB. As well there are circumstances where services that are provided by utilities are not rate-regulated such as the provision of water-meter reading and billing services. Shareholders are to assume the liabilities and fund the costs of all such activities that are not rate-regulated and separate accounts are provided in the electricity and gas Uniform Systems of Accounts to capture all such revenues and related expenses so they can be tracked and verified as separate from the rate-regulated activities of the utility.
- 3.2 Employees may perform activities within the entity that relate to services that are both rate-regulated and not rate-regulated. The OPEB costs associated with compensation of employees for services that are not rate-regulated are required to be excluded from costs that are included in determining rates.
- 3.3 Justification of the basis upon which OPEB costs are attributed to rate-regulated activities should review the applicability of all key assumptions to the regulated and unregulated segments of the business and reflect any inherent differences in the underlying workforce. By way of example, this includes consideration of such matters as expected remaining years of service, uniformity of expected health care costs, etc. The basis of attribution to the rate-regulated business should also provide suitable rationale for including costs arising from past service, particularly in cases where a new aspect of the business has recently become rate-regulated.
- 3.4 Where the structure of a regulated enterprise has changed, e.g., through the inclusion or removal of assets that are subject to rate-regulation or through merger or acquisition, the basis of attribution of OPEB costs may change.
- 3.5 There may be instances where there is a transfer of a group of employees into or out of an OPEB plan that is not due to a structural change in the enterprise. It is expected that the

value of consideration given in the transfer will finance any deficit attributed to the transferees.

- 3.6 The OEB may find an actuarial assessment and valuation helpful at the trigger point of a structural change to determine the revised allowed portion, but this is not necessarily cost effective and therefore is generally not required.

Information Requirements

- 3.7 In its rates rebasing application, consideration should be given to whether a utility should be required to justify the basis upon which OPEB costs have been attributed to rate-regulated activities and differentiate the basis, to the extent practical, from how they are attributed to non-rate-regulated activities.**

- 3.8 Where the structure of a regulated enterprise has changed, consideration should be given to whether a utility should be required to provide a review and analysis of the attribution of OPEB costs to the ongoing rate-regulated enterprise at the next proceeding in which it seeks to rebase rates. Such analysis includes identification of amounts not recovered or over-recovered in rates during the preceding rate period attributed to the structural change.**

- 3.9 Consideration should be given to whether a utility should be required to disclose in its rates rebasing application any instance where a group of employees has transferred into or out of its OPEB plan and the amount of related consideration. In cases where the consideration given in the transfer does not finance any deficit, the implications will be considered by the OEB on a case-by-case basis consistent with the method by which amounts are included in rates.**

- 3.10 Consideration should be given to whether a utility should maintain appropriate records to enable assessment of the reasonableness of the allocation of OPEB costs between rate-regulated and any non-rate-regulated activities.**

- 4. *OPEB costs are reasonable*** – *OPEB and related costs should be determined, where applicable, using actuarial methods and assumptions in line with professional standards and current best practice.*

Background Information

- 4.1 In general, assessing the fit with best practices, including the appropriateness of key assumptions used in the measurement of OPEB plan assets and/or obligations, is a means for the OEB to build confidence in the measurement of associated costs.

- 4.2 The actuarial assumptions used by an OPEB plan may be grouped into two categories: demographic assumptions and, economic (or financial) assumptions. The demographic assumptions reflect attributes of the employer's workforce and retirees and include, but are

not limited to: the estimated average remaining years of service of the active employees, the estimated termination rate for employees, and mortality rates assumed for key groups of members of the plan (e.g., male, female). The values assigned to the economic (or financial) assumptions include expectations associated with parameters external to the enterprise and include, but are not limited to: long-term interest rates used to set the discount rate, the expected rate of return on the various categories of invested assets (where applicable) and estimated inflation and escalation rates applicable to health care benefit costs.

Information Requirements

4.3 In its rates rebasing application, consideration should be given to whether a utility should be required to provide the history of benefit plan changes (any improvements or reductions in benefits, or, where funded, changes in employer/employee contribution levels) that have occurred over the 10 year period preceding a rates rebasing application with an explanation of the rationale for each change and its impact on cost.

4.4 Consideration should be given to whether a utility should be required to provide a breakdown of total compensation cost and OPEB cost showing separately the amount attributed to capital expenditures and the amount attributed to operating expenditures.

4.5 Consideration should be given to whether a utility should be required to provide OPEB costs separated between funded and unfunded OPEB plan costs.

Defined Benefit (“DB”) OPEB plans

4.6 Consideration should be given to whether a utility should be required to include in its rate rebasing application a description of the actuarial cost method used to determine the value of the underlying DB obligation (e.g., projected benefit method, entry age normal method) and the method used to determine amounts attributed to capital expenditures and amounts attributed to operating expenditures, for its DB OPEB plan(s). The utility should be required to explain any deviations from what is considered actuarial best practice along with an explanation of the implications of any such deviations.

4.7 Consideration should be given to whether a utility with DB OPEB plan(s) should be required to identify the key assumptions it has used in determining OPEB costs included in rate rebasing applications.

4.8 Consideration should be given to whether a utility should be required to provide the history of values for all key assumptions it used in DB calculations accompanied by explanations of any changes in the assumed values over the 10 year period preceding

a rate rebasing application. In order to benchmark costs as a means of assessing their reasonableness, utilities should be required to provide, for DB plans, external reference information as applicable regarding the range of acceptable values used by other plans for actuarial assumptions including (but not limited to) mortality rates, discount rates, expected rates of return on funded plans and estimated inflation and escalation rates applicable to health care benefit costs.

- 4.9** Consideration should be given to whether the reference information required in 4.8 should describe the drivers that could influence the choice of assumption value for an individual DB plan from within the range of acceptable values. Consideration should be given to whether a utility should explain its choice of a particular value within the range of acceptable values, and provide cost sensitivity analysis associated with key assumption values.

Defined Contribution (“DC”) OPEB plans

- 4.10** Consideration should be given to whether a utility should be required to disclose in its rates rebasing application whether the application includes any increases or decreases in contribution rates to OPEB plans that are treated as DC plans. If an increase or decrease in contribution rates can be reasonably forecast, consideration should be given to whether a utility should be required to provide such forecast (by years), documentation to support the forecast and state how the utility proposes to address the forecast amounts.

- 5. OPEB cost information is reliable** - Amounts of OPEB costs included in rates should be based on and supported by amounts that have been provided and assessed by independent experts.

Background Information

- 5.1 General stated objective 4 requires the utility to demonstrate that its OPEB costs are reasonable. General stated objective 5 is concerned with ensuring that the calculations and other information provided by the utility is reliable so that it can be used with confidence by the rate-regulator for making decisions.
- 5.2 The OEB is authorized under governing legislation when establishing rates that are just and reasonable, to use any method that it considers appropriate that is consistent with its objectives. The OEB is informed by values included in a utility’s audited financial statements, including the accounting cost and employer’s funding contribution amount or direct payment that are audited in relation to codified auditing standards. In addition, the accounting standards and actuarial standards provide for the determination of cost on the basis of methods that are systematic and rational. The result of using such values, at least as a starting point for consideration in setting rates, is increased confidence that the information

is reliable. In addition, the OEB's Reporting and Record-keeping Requirements require periodic reporting including the provision to the OEB of audited financial statements. As such the OEB has the ability to seek reconciliation between amounts granted in rates proceedings and amounts ultimately reported in audited financial statements.

- 5.3 There are currently differences among the various accounting frameworks (e.g., International Financial Reporting Standards ("IFRS"), US Generally Accepted Accounting Principles ("US GAAP"), and Canadian Accounting Standards for Private Enterprises ("ASPE")) as to how OPEB costs are treated in the context of DB OPEB plans.
- 5.4 It may not be appropriate to enumerate the differing treatments among the various accounting frameworks in regulatory Information Requirements, particularly as they are changing over time. However, in reviewing rate applications in years soon after an accounting framework transition, particular attention should be made to the implications for OPEB costs in areas where there are known differences between the former accounting framework and the newly adopted accounting framework.

Information Requirements

- 5.5 Consideration should be given to whether a utility should be required in its rates rebasing application to provide a reconciliation of historical rate year OPEB cost information to OPEB cost information contained in audited financial statements, explaining any differences.**
- 5.6 Consideration should be given to whether a utility should be required in rates rebasing applications to provide evidence, where the cost impacts would potentially be material in the year of rebasing or succeeding years, regarding the amount of OPEB cost differences arising because of any transition to a new accounting framework that it has undertaken or plans to take in the incentive regulation period. Consideration should be given to whether the evidence should state how any such differences are proposed to be dealt with in relation to utility customer rates and reference any previous related decisions of the OEB.**
- 5.7 Consideration should be given to whether a utility should be required to provide in its rates rebasing application copies of all actuarial studies and reports, valuations or assessments provided to the utility since the last rebasing of rates with respect to its OPEB plans whether or not used in establishing the amounts included in the rates application or recorded in the audited financial statements.**
- 5.8 If a utility applies to the OEB for rate rebasing and its most recent actuarial report is dated as at a date more than two years prior to the end of the most recent historical year included in the application, consideration should be given to whether the utility**

should be required to obtain an actuarial update with respect to the calculation of DB OPEB plan accounting costs included in the historical year financial statements.

6. *OPEB costs are recovered over an appropriate time period* - Reasonable OPEB costs should be included in customer rates in time periods as close to the time periods to which they relate as is reasonable while recognizing the need for rate stability and predictability.

Background Information

- 6.1 The various accounting frameworks used in Canada, including IFRS, ASPE, and US GAAP specify whether, how, when, and over what time periods costs are to be recognized in the financial statements. Such accounting methods may or may not attribute costs to time periods that appropriately reflect the interests of utility customers.
- 6.2 OPEB costs are calculated differently depending on whether the employer plan is a DC plan or a DB plan. The complexity of calculation is much greater with DB plans.
- 6.3 For funded DB plans there are three OPEB values already determined for various purposes that the OEB could choose as the basis for inclusion of cost in customer rates. These are:
- a) The cash amount ultimately paid to or on behalf of beneficiaries (i.e., look-through the OPEB plan and establish the amount that is paid to the plan's beneficiaries in each period – 'pay-as-you-go' method);
 - b) If the OPEB plan is funded, the amount contributed to meet targeted funding levels (designed to ensure financial health of the plan over the long term); or
 - c) The amount specified by accounting standards for inclusion in audited financial statements (accrual basis of accounting).

For DB plans that are not funded, b) above is not applicable.

An alternative approach could be developed to recover OPEB costs in rates charged to customers based on actual 'pay-as-you-go' cash payments that are adjusted by an additional amount that the OEB establishes to be just and reasonable based on a utility's facts and circumstances (i.e. "adjusted 'pay-as-you-go' cash payments method"). Under this method, 'pay-as-you-go' cash payments are the starting point (foundation) for determining the amount that is included in rates. However, such 'pay-as-you-go' cash payments are increased by an additional amount that is established by the OEB.

DC OPEB Plans

- 6.4 In the case of DC OPEB plans, the calculation of the employer's contribution amount is relatively straightforward because the OPEB-related risk rests with the individual plan

members and not the utility. For a DC OPEB plan, the employer's cash contribution for a year is dictated by the plan's contribution formula (e.g., a predetermined amount for specified benefits) and relates to benefits earned by employees during the current year.

- 6.5 For all DC plans, the amount recognized for accounting purposes in a period consists of the contribution payable by the utility for service rendered during the period. The contribution payable to the plan for the period is recognized as an expense except to the extent that another accounting standard requires or permits their inclusion in the cost of an asset (e.g. property, plant and equipment or intangible asset).

Single Employer DB OPEB Plans

- 6.6 In the case of a single-employer DB OPEB plan, the calculation of costs for accounting and/or funding purposes is far more complex than the determination of the DC accounting cost because the utility bears the risk of meeting the obligations defined by its plans. Accounting principles require amounts associated with the benefits provided to employees to be recognized during the period in which the obligation to provide benefits to the employees arises, not when it is paid. Calculation of the amounts requires an actuarial valuation. The applicable standards set out the methods that must be used for DB OPEB plan accounting valuations and how to set the assumptions, which include (as per 4.2 above):

- Economic (or financial) assumptions such as discount rates, expected returns on the various categories of invested assets (where applicable), and estimated inflation and escalation rates applicable to health care benefit costs; and
- Demographic assumptions such as mortality, retirement and termination rates.

- 6.7 There are no statutory funding requirements for OPEB plans. The amount actually contributed to a DB OPEB plan, if any, in a given year will often differ substantially from the cost recognized for that year for accounting purposes and from the total amount paid directly to the plan's beneficiaries.

- 6.8 Where OPEB plans are unfunded, the utility's cash payment amounts are amounts paid to or on behalf of former employees, including retirees, and do not relate to the value of benefits earned by current employees of the utility. The accounting values do include the value of benefits earned by current employees.

- 6.9 If a utility considers that it faces undue financial hardship (or has earned an unexpected windfall) during the period of an incentive rates regime, there are a number of means that it can use to apply directly to the OEB to address the issue, or the OEB can use to address over earnings.

Information Requirements

- 6.10** For OPEB plans accounted for as DC plans, consideration should be given to whether a utility should be required to include in cost for purposes of determining rates the same cost value as is determined for accounting purposes.
- 6.11** For DB OPEB plans, consideration should be given to whether a utility should be required to include in cost for the purpose of determining rates the same value as is determined for accounting purposes or, alternatively, the utility's adjusted 'pay-as-you-go' cash payments.
- 6.12** Consideration should be given to whether a utility should be required to apply a set-aside mechanism as determined by the OEB in order to support the use of the accrual accounting cost method in determining the rates charged to customers.
- 6.13** If the accounting framework that is used by a utility does not periodically reclassify to net income the component of OPEB costs that is recorded in OCI, consideration should be given to whether a utility should be required to record that amount in a deferral account that is amortized and included in rates based on the expected average remaining service life of the members of the OPEB plan.
- 6.14** Consideration should be given to whether a utility with an OPEB plan (or plans) accounted for as DB plan(s) should be required to provide in its rates rebasing application a description for each plan and the method for including its costs in rates (including the basis for allocation between current period expenditures and capital expenditures).
- 6.15** Consideration should be given to whether a utility should file evidence to support any deviation from any requirements the OEB may establish with respect to points 6.10, 6.11, 6.12 and 6.13 above.
- 6.16** Consideration should be given to whether a utility should be required to provide in its rates rebasing application evidence regarding the sensitivity of the OPEB cost calculation to changes in the key assumptions used in calculating the amounts. Such evidence should include analysis and discussion of the potential impact of key assumptions (such as discount rates and healthcare costs) on OPEB costs and customer rates.

Other Considerations

- 6.17** The impact of any policy change from the 'pay-as-you-go' method for determining OPEB cost for single-employer OPEB plans to using same cost value as is determined for accounting purposes only affects a small number of utilities in a significant manner (albeit that the impact on these affected utilities could be significant to the individual

utility). Consideration should be given to whether a utility that is affected by this change should be required to apply directly to the OEB for a deferral account to capture the difference caused by the transition so it can be considered for disposition in rates in future years.

6.18 The impact of any policy change from determining OPEB cost for single-employer OPEB plans using the same cost value as is determined for accounting purposes to using the adjusted ‘pay-as-you-go’ cash payments method could affect a large number of utilities. Consideration should be given to whether a utility that is affected by this change should transition to the new requirements based on the specific guidance that is issued by the OEB in this regard.

6.19 Consideration should be given to whether a utility that changes its policy for determining the amount of OPEB cost included in rates should be required to disclose such fact in its rates rebasing application and to state the impact of such change. If the change also results in a material balance of unrecovered cost or an excess of cost previously recovered in rates, consideration should be given to whether the utility should be required to disclose such impact in its application and propose the means by which the OEB should authorize its disposition in rates.

Appendix A – Types of P&OPEB Plans and Actuarial Valuation Methods

Post-employment benefit arrangements represent a form of deferred compensation and are commonly thought of in the context of pension and retiree health benefits but may also include specified benefits, such as life insurance outside of a pension plan, tuition assistance, day care, legal services, and housing subsidies provided after retirement. Typically, these benefit arrangements are provided through P&OPEB plans. Both funding of and accounting for these benefit arrangements is complicated by the fact that the benefits are payable after the completion of employment; often, this can be several decades after the date when service by an employee first gives rise to benefits under the arrangement.

Types of pension plans & typical characteristics

	DC	DB	DB MEPP	JSPP
Characteristics				
Employee bears investment, interest and longevity risk	Yes	No	Sometimes	Yes
Employer bears investment, interest and longevity risk	No	Yes	Yes	Yes
Employee pension benefit is known in advance	No	Yes	Yes	Yes
Employer contributions are set in advance	Yes	No	No	No
Employer funds deficits	N/A	Yes	Yes	Yes
Employee funds deficits	N/A	No	No	Yes
Types of plan for the Utility companies in Ontario				
Funded and unfunded pension plans of Hydro One, OPG, Enbridge, Union Gas	No	Yes	No	No
Pension plan of LDCs - OMERS (funded collectively) (accounted for as a DC plan)	No	No	No	Yes
<i>Note: Typically, OPEBs are not funded but provide DB benefits (except for certain of Enbridge's plans in the US)</i>				

DC – Defined Contribution Pension Plan DB – Defined Benefit Pension Plan
MEPP – Multi-Employer Pension Plan JSPP – Jointly Sponsored Pension Plan

Defined benefit (“DB”) pension and other post-employment benefits (“OPEB”) plans are intended to provide a known, pre-determined benefit (for example, 1.5% of salary per year of service) in a future period. In Ontario, registered DB pension plans (those pension plans that are required to be registered with the Financial Services Commission of Ontario and also have met requirements for registration with the Canada Revenue Agency in order for the sponsoring employer to qualify for tax benefits) must be funded in advance and contributions can fluctuate depending on the pension plan’s experience. OPEB plans, as well as other non-registered DB pension plans such as SERPs,

are not required by law to be funded in advance, and the cash payments are often paid directly from the employer to the plan beneficiaries. Depending on the plan, employees may be required to pay contributions to DB plans, typically as a percentage of salary; however the investment, longevity and interest rate risks all fall on the employer.

Defined contribution (“DC”) plans are post-employment benefit plans under which an entity pays fixed contributions into a separate entity (a fund) and will have no legal or constructive obligation to pay further contributions if the fund does not hold sufficient assets to pay for the benefits relating to employee service in the current and prior periods. The employers’ obligation is limited to the amount that it agrees to contribute to the fund. Thus, the amount of the post-employment benefits received by the employee is determined by the amount of contributions paid by an entity (and perhaps also the employee) to the plan or to an insurance company, together with investment returns arising from the contributions. In consequence, actuarial risk (that benefits will be less than expected) and investment risk (that assets invested will be insufficient to meet expected benefits) fall, in substance, on the employee.

As such, DC plans work in the opposite manner to DB plans, requiring a fixed level of employer contributions, while benefits will fluctuate depending on the performance of fund investments. In other words, payout amounts are determined by the available funds in an individual’s DC account in future periods. In a DC plan, the investment, longevity and interest rate risks all fall on the employees and retirees.

Pension plans can be single-employer or multi-employer pension plans (or “MEPPs”)¹. A MEPP allows several employers who are often part of the same industry to pool their funds together and reduce administration costs, and also provides continuity in the benefits of employees who frequently change jobs between participating employers. Each MEPP participating employer (and typically employees as well) pays contributions based on the same rules, which are often based on hours worked by employees.

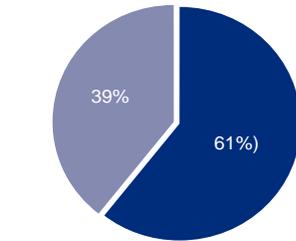
There is a sub-type of DB MEPP called a jointly-sponsored pension plan (or “JSPP”). A JSPP is special type of MEPP where employees are required to fund deficits along with the employer, and therefore the employee is sharing some of the risks. The JSPPs in Ontario include Ontario Municipal Employees’ Retirement System (OMERS), Healthcare of Ontario Pension Plan (HOOPP) and Ontario Teachers’ Pension Plan (OTPP), among others.

The table below shows membership to OMERS as at December 31, 2014:

¹ See Section 1.3 of Appendix C for additional details regarding multi-employer plans.

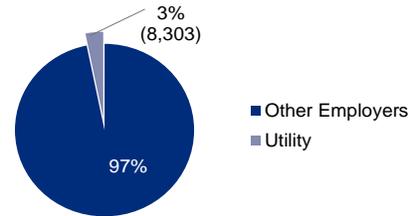
OMERS employer categories summary

Membership Headcount



Active	275,044
Non-Active	176,071
Total	451,115

Active Headcount



Active

Category	Percentage distribution of actuarial liabilities	Percentage distribution of contributions
Utility	5.1%	4.2%

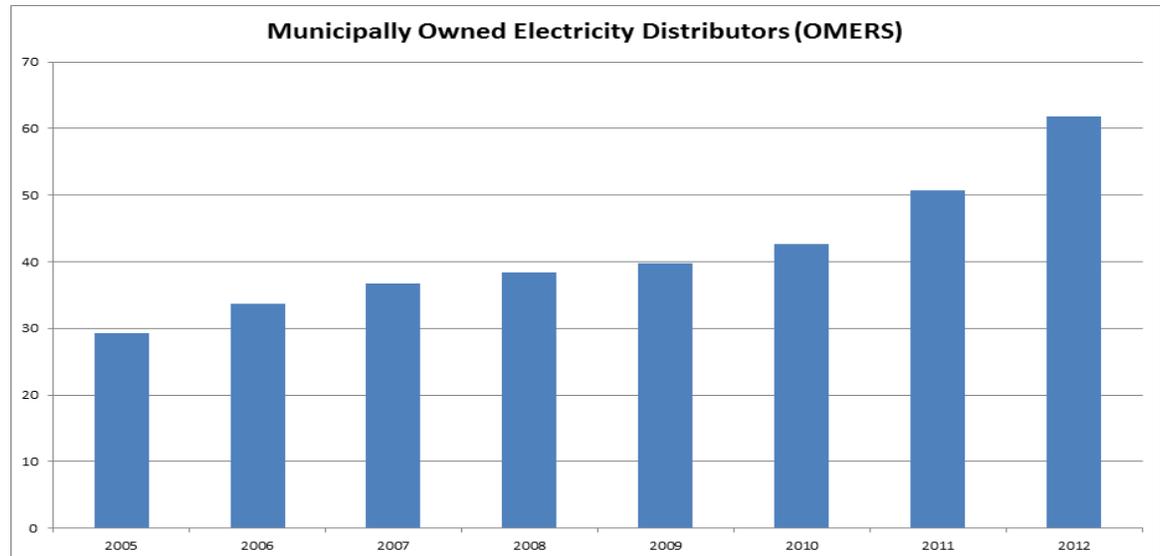
Key financial information of OMERS at December 31, 2014:

- Net assets available for benefits: \$72B
- Accrued pension liabilities: \$77B
- Funding deficit: \$7.1B

Utility sector contributions are funding approx. \$300 million of the OMERS deficit

Source: OMERS website

Employer contributions to OMERS by Municipally-Owned Electricity Distributors during the 8-year period that ended in 2012 were as follows (amounts in \$m)¹:



DB Plans – the need for actuarial valuations

¹ Source: based on aggregated data provided by OMERS. The data does not identify individual employers.

As noted above, a DB plan has to pay out benefits to members as per the definitions in the plan's terms. While members often pay some contributions towards the funding of those benefits, the sponsoring employer(s) will be responsible for making sure there are sufficient assets in the plan to pay the benefits as they become due. Actuaries perform actuarial valuations to place a value on the benefits promised so that plan sponsors can understand the size or value of the obligation promised: the actuarial benefit liability.

The inputs in an actuarial valuation include an actuarial cost method, a set of assumptions, plan member data and the DB plan benefit rules. There are various types of actuarial valuations, each performed for a different purpose (see "Funding valuations" section below). These different actuarial valuations can be applied to the same pension plan with the same membership and rules, but use different methods and different values for the assumptions and arrive at different benefit liability values.

In DB plan actuarial valuations, assumptions are made for key economic variables including discount rates, inflation and salary increases, and key demographic variables including mortality, retirement and termination rates.

In calculating the obligation and the current service costs, the assumptions, membership data and plan rules are used to determine a projected stream of future benefit payments in respect of past service and the current year's service respectively. Discount rates, which are typically the economic variables that have the most significant impact on the actuarial benefit obligation, are used to determine the present value of the stream of projected future benefit payments. Therefore, a lower discount rate will result in higher benefit obligations and current service costs (or normal costs), and vice versa. Recently, interest rates have reached historic low levels, resulting in significantly increased present value of benefit obligations and current service costs (or normal costs) that are recognized in each period.

The sensitivity is particularly pronounced for a large plan such as OMERS where an increase/decrease of 50 basis points in the real discount rate, with no change in other assumptions, would cause approximately \$5.9 billion decrease/ increase in the total accrued pension obligation of the plans.¹ The OMERS plan deficit as at December 31, 2014 was \$7.1 billion on a defined benefit obligation of \$77 billion. As noted in the graphic above, the utility portion of this is approximately 5%.

Because, in general terms, the longer an individual lives, the longer DB pensions must be paid, mortality rates are a key demographic assumption in a pension plan valuation. In 2013, a new set of draft mortality tables was released by the Canadian Institute of Actuaries, which better reflect the reality that Canadians are living longer. A final version of the tables was released in 2014. For many pension and OPEB plans, the improvement to mortality shown in the new mortality tables was

¹ OMERS 2014 Annual Report, Discount Rate, page 84.

included in accounting and going concern valuations in late 2013 or early 2014.¹ The new tables have been commonly estimated to increase liabilities and normal costs by 3-10% depending on the pension plan.

Funding valuations

In Ontario, there are no statutory funding requirements for OPEB plans and unregistered pension plans. As such, if an entity wishes to fund its OPEB plans and/or unregistered pension plans (e.g. in order to meet a targeted internal funding level designed to ensure financial health of the plan over the long term), the funding expectations would be established by the entity based on the advice that it receives from its actuaries. The vast majority, if not all, of the utilities in Ontario do not fund their OPEB plans and unregistered pension plans.

For registered DB pension plans, a “funding valuation” is required by legislation and is used to determine the minimum contributions that plan sponsors must pay to fund the promised benefit, as well as the maximum contributions that will qualify for tax deductibility.

Under current regulations for ongoing DB pension plans in Ontario, actuarial valuations for cash funding purposes are performed annually (triennially, if a certain prescribed level has been achieved) to determine the level of the surplus or deficit in the plan on a “going concern”, “solvency” and “wind-up” basis.

- A going concern valuation compares the relationship between the value of a pension plan’s assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the pension plan will be maintained indefinitely. As such, the going concern valuation is performed by taking a long-term view of the pension plan, and assumes the plan will continue to operate for the foreseeable future. Going concern “special payments” are calculated by spreading any resulting going concern deficit over a period of 15 years.
- A solvency valuation determines the financial position of a pension plan in a similar manner to the hypothetical wind-up basis (see below), except for certain specific differences that exist due, in part, to the fact that deficits under the solvency valuation are required to be funded for an ongoing pension plan, while wind-up deficits must only be funded if an actual wind-up of the plan is taking place. The solvency valuation assumes the plan is terminated immediately, however it may include averaging mechanisms which smooth the impacts of short term volatility in the pension plan’s financial position.
- A hypothetical wind-up valuation determines the relationship between a pension plan’s assets and its liabilities assuming that the pension plan is wound up and settled on the valuation date, and benefits are settled in accordance with the PBA and under circumstances that produce the maximum wind-up liabilities on the valuation date (however, in performing the valuation, an

¹ Based on the Canadian Institute of Actuaries *Educational Note Supplement: Canadian Pensioners Mortality* dated October 30, 2013, which recommended reflecting improved mortality assumptions for plans where there is an absence of quantifiable evidence which suggests otherwise.

actuary may disregard certain items). As such, similar to the solvency valuation, the hypothetical wind-up valuation assumes the plan is terminated (or “wound-up”) immediately. However, there are no averaging mechanisms used.

If the solvency deficit is greater than the present value of 5 years of existing going concern and solvency special payments, then the plan sponsor must also make solvency “special payments” to fund the excess deficit. In this case, any excess deficit is amortized over a period of 5 years.¹

In addition, if the plan is open to future accruals (i.e., is an ongoing plan), the plan sponsor must meet the annual cost of providing these benefits that is in excess of the employees’ contributions, i.e. the “annual normal cost” of the benefits provided by the plan’s sponsor. The employer’s annual normal cost (or current service cost) is the estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that accrues in a respective annual period after the valuation date, assuming a pension plan will be maintained indefinitely, less employee contributions in respect of that period.

Assuming the plan is ongoing, the total of the employer’s current normal cost, going concern special payments (if any) and solvency special payments (if any), represents the employer’s minimum required contribution. The total of the employer’s normal cost plus the larger of the going concern deficit and the windup deficit represents the employer’s maximum tax deductible contribution.

Actuarial funding valuation assumptions

The tables below outline the components used to set assumptions in going concern, solvency and wind-up valuations. As detailed above, these are the valuations used to determine minimum funding contribution requirements and for tax purposes, the maximum tax deductible contributions:

¹ In certain circumstances, this period may be extended to up to 10 years as part of a temporary relief initiative. However, this requires that no more than one-third of eligible members, former members and retired members object to the extension.

Key economic assumptions and methods Going concern

Going Concern Assumptions	
Assumption	Based On:
Discount rate used for present value of benefits	<ul style="list-style-type: none"> ■ Expected long-term inflation rate ■ Expected long-term return on asset portfolio <ul style="list-style-type: none"> – Typically over 20 years ■ Margin for adverse deviations ■ Allowance for administrative and investment expenses
Salary scale used to project pension at termination/retirement	<ul style="list-style-type: none"> ■ Expected long-term inflation rate ■ Expected increase in average wages in the economy ■ Company's compensation philosophy
Indexation rate used to increase pensions in deferral and in payment	<ul style="list-style-type: none"> ■ Expected long-term inflation rate

Assumes the plan will continue for the foreseeable future;
Assumptions are long-term

- Asset methodology** - Smoothing or market value
- Smoothing may be over a maximum of 5 years
 - Delays recognition of fluctuations in market value due to investment experience

Key economic assumptions and methods Solvency and wind-up

Solvency and Wind-up Assumptions	
Assumption	Based On:
Discount rates used for present value of benefits	<ul style="list-style-type: none"> ■ Government of Canada benchmark bond yield, using: <ul style="list-style-type: none"> – Long-term; – 7 year; and – Average for marketable bonds over 10 years ■ Guidance from Canadian Institute of Actuaries
Indexation rate used to increase pensions in deferral and in payment	<p>Inflation rate implied by:</p> <ul style="list-style-type: none"> ■ Government of Canada long-term real-return bond yield (monthly) ■ Guidance from Canadian Institute of Actuaries

Assumes the plan is wound up at the valuation date

ON government currently undertaking review of solvency funding framework (consultation paper expected Spring 2016)

- Discount rates**
- For solvency: averaging of discount rates is permitted (up to 5 year average)

- Asset methodology**
- For solvency: smoothed or market value
 - Smoothing may be over a maximum of 5 years
 - Delays recognition of fluctuations in market value due to investment experience

Actuarial assumptions and methods used for going concern, solvency and wind-up valuations are set by actuaries in accordance with accepted actuarial practice and any applicable laws, in conjunction with input from plan sponsor management.

Accounting Valuations

In addition, actuaries provide valuations for inclusion in a plan sponsor's financial statements, or accounting valuations. The applicable accounting standards set out the methodology that must be used for these accounting valuations and how to set the actuarial assumptions. The key actuarial assumptions used in accounting valuations depend on the applicable accounting framework and include the following:

- Discount rate;
- Indexation and price inflation adjustments for medical benefits;
- Expected return on plan assets;
- Mortality and average remaining working life; and
- Rate of employee turnover, salary and pension increases.

As pension costs are an estimate of the costs that will be incurred in the future, it is not possible to establish precise measurement of the cost relating to an individual period; the costs are established by using estimates and assumptions that fall within an acceptable range (often as identified and recommended by the utility's actuary after taking into account accepted actuarial practice and any applicable laws). In some instances, a utility's management may be able to impact the accounting costs that are recognized by the utility as a result of selecting specific actuarial assumptions within these acceptable ranges.

Actuarial Valuation Method

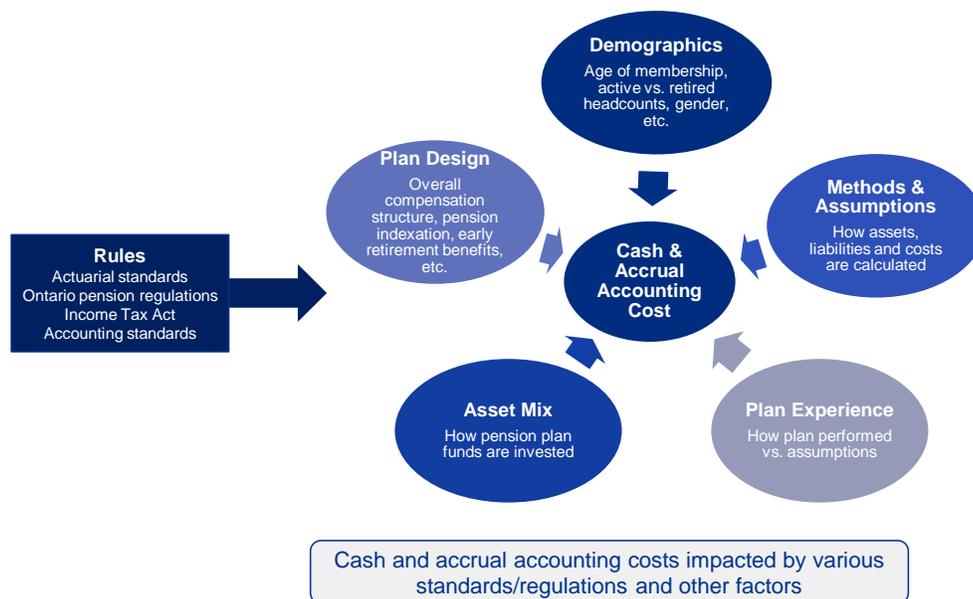
The cost method applied in an actuarial valuation determines how the total projected costs of the defined benefits promised to an employee will be spread out over the employee's working service life. Accounting standards require the use of the projected unit credit cost method, an actuarial valuation method that sees each period of service as giving rise to an additional unit of benefit entitlement and that measures each unit separately to build up the final obligation. This method is sometimes known as the accrued benefit method pro-rated on service or as the benefit/years of service method.

Differences between funding valuations and accounting valuations are significant because they are defined by different frameworks which have specific and separate methodologies for setting assumptions and calculating costs. Section 2.3.2.1 provides an illustration of the extent of these differences for Ontario Power Generation for the period from 2008 to 2015.

Appendix B – Cost Drivers for P&OPEB Costs and Plan Governance

Various factors impact a utility’s reported P&OPEB costs. In addition to other issues arising from an individual utility’s employment and compensation structure/ practices, the following cost drivers impact costs associated with a utility’s P&OPEB plans:

Pension and OPEB plan cost drivers



As illustrated above, both the accrual accounting cost and the employer’s cash funding contributions to DB plans are influenced by many factors. In some cases, applicable rules and guidelines constrain the degree to which these factors can vary, and the level of control that a utility will have over these factors. The table below is a high-level analysis of the extent of unilateral control that an individual employer can exercise over various factors that affect a utility’s P&OPEB costs.

Individual employer's control of certain factors affecting the cost of P&OPEB plans

Factor	Pension		OPEB	
	OMERS	Non-OMERS	Self-Insured	Fully-Insured
Staffing practices	✓	✓	✓	✓
Plan design	*	✓	✓	✓
Funding policy	*	✓	✓	N/A
Accounting policies	N/A	✓	✓	✓
Investment policy and asset mix	*	✓	Typically N/A	N/A
Assumptions, methods	*	✓	✓	✓
Compensation philosophy	✓	✓	✓	✓
General market returns	*	*	Typically N/A	N/A
Interest and inflation environment	*	*	*	N/A
Plan member behavior	*	*	*	*
General health care cost changes	N/A	N/A	*	*
Utilization rates	N/A	N/A	*	*
Insurance premiums	N/A	N/A	N/A	*
Fees and expenses	*	✓	✓	✓
Service provider selection	*	✓	✓	✓
Applicable rules and standards	*	*	*	*

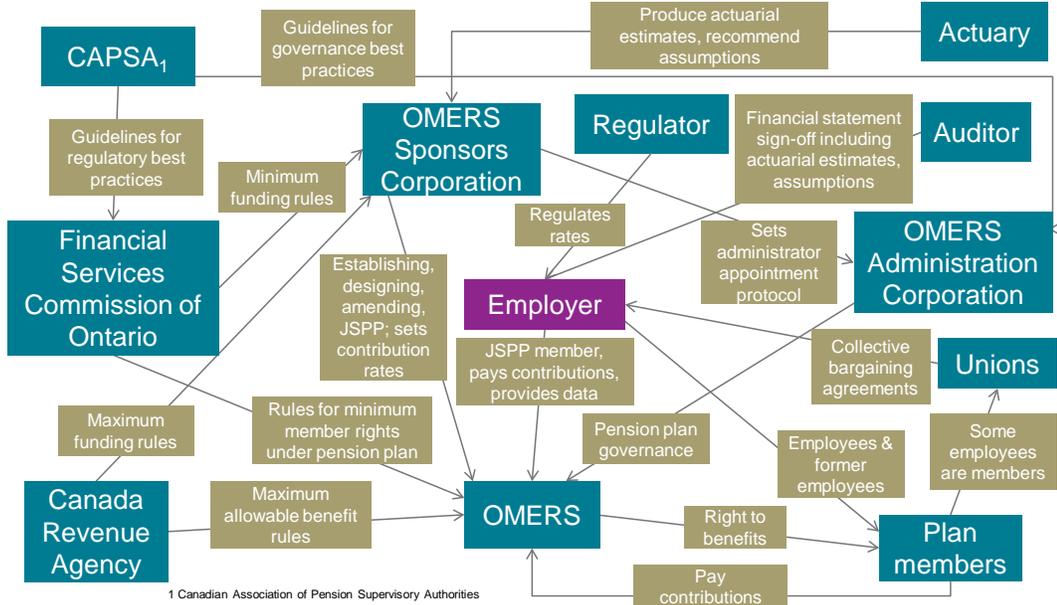
✓ Mostly controllable
* Less or non-controllable

Individual employer has limited influence on OMERS pension plan and on OPEB funded through third party insurance

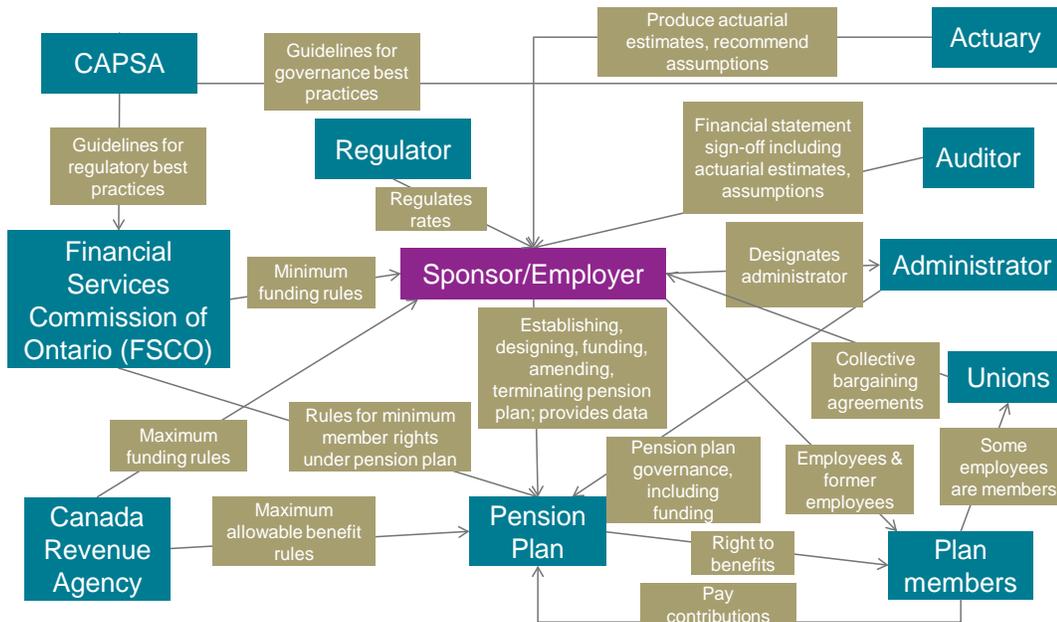
Because multiple employers participate in OMERS, the extent of influence of an individual utility's management is very limited, compared to utilities with standalone pension plans. Participation in the OMERS plans is optional for all eligible employers. There is no requirement for an eligible employer to participate under the OMERS Act or its governing rules. However, once an employer does elect to participate, it can only withdraw its participation if 100% of its participating members agree and the Sponsor's Corporation (responsible for strategic oversight and decision-making by sponsors on major policy directions including benefits and contribution rates) approves the withdrawal. With respect to participation in another pension plan, OMERS has an exclusivity clause. Under the exclusivity clause, municipalities and local boards can only participate in OMERS if they wish to participate in a pension plan. The clause does not apply to municipally owned utilities which are free to participate in other registered retirement vehicles.

As illustrated below there are many similarities, as well as some key differences between the governance model, regulatory framework and stakeholders for OMERS as compared to a single-employer DB pension plan. The various aspects of pension plan oversight and governance are described in Appendix E.

Pension Overview: OMERS - Complex relations & interactions among oversight bodies and selected other stakeholders



Pension Overview: DB Single-employer plan - Complex relations & interactions among oversight bodies and selected other stakeholders



Appendix C – Differing Accounting Frameworks for P&OPEB Plans

1.1 Defined contribution (“DC”) plans

DC plans are described in Appendix A. Accounting for DC plans is straightforward because the reporting entity's obligation for each period is determined by the amounts to be contributed for that period. Consequently:

- No actuarial assumptions are required to measure the obligation or the expense as the contribution required for each period is limited to a fixed, agreed amount. There is no possibility of any actuarial gain or loss; and
- The obligations are measured on an undiscounted basis, except when they are not expected to be settled (or paid) wholly before twelve months after the end of the annual reporting period in which the employees render the related service.

The contributions payable to a defined contribution plan are recognized as an expense (unless capitalized as part of the cost of an asset) as the obligation to make contributions is incurred. Generally, this is when an employee renders service during each period.

1.2 Defined benefit (“DB”) plans

DB plans are also described in Appendix A. As the sponsor bears some of the actuarial and investment risks of the plan, for accounting purposes the expense recognised for a DB plan is not necessarily the amount of the contribution due for that period.

For accounting purposes, the DB costs are made up of the following components:

- a) **Service costs** – this comprises of three components:
 - The increase in the present value of the defined benefit obligation due to employee service in the current period (“*current service costs*” or “*normal cost*”);
 - The change in the present value of the defined benefit obligation for employee service in prior periods resulting from retroactive plan amendments such as the introduction or withdrawal of, or changes to, the plan or a significant reduction by the entity in the number of employees covered by the plan (all collectively referred to as “*past service costs*”); and
 - Any gain or loss on settlement¹ of the defined benefit obligation.
- b) **Interest cost** – In the context of P&OPEB accounting, interest costs represent the accretion of the defined benefit obligation due to the passage of time. The amount is the result of unwinding

¹ For DB plans, a settlement is a transaction that eliminates all further legal or constructive obligations for part or all of the benefits provided under a DB plan, other than a payment of benefits to, or on behalf of, employees that is set out in the terms of the plan and included in the actuarial assumptions.

from period-to-period the effect of discounting applied in calculating the present value of the obligation;

- c) **Return on invested plan assets** – The expected return on invested plan assets is forecast at the beginning of each year. For unfunded plans (which is the case for most OPEB plans and SERP), there is obviously no return on plan assets as the plans do not have plan assets to invest;
- d) **Actuarial gains and losses** – These arise from experience adjustments (i.e. the effects of differences between previous actuarial assumptions and what has actually occurred) and changes in actuarial assumptions. In addition, for funded plans, there is also a difference between the expected return on plan assets (or notional amount based on the net defined benefit liability/asset position) and the actual return.

The obligation for the defined benefit plan is presented in the statement of financial position net of the related plan assets and can be a net asset or a net liability.

1.3 Defined benefit plans accounted for as DC plans

Multi-employer plans

Multi-employer plans are also explained in Appendix A. Multi-employer plans are classified as either DB plans or DC plans depending on the economic substance of the plan. However, as a practical expedient, when a plan sponsor does not have access to the information required to apply DB accounting to their share in a multi-employer plan, accounting standards provide an exception and the plan sponsor is required to account for the plan as a DC plan - i.e., contributions are only recognized as they become due. All the utilities in Ontario that participate in the OMERS plan fall into this category. As such, these utilities only recognize as pension expense the cash contributions that they are required to make to OMERS during each period even though they are exposed to the actuarial and investment risks of the plan.

It is important to note that multi-employer plans are different from multiple-employer plans. Multiple-employer plans are those plans that are intended to allow participating employers, commonly in the same industry, to pool their assets for investment purposes and reduce the costs of plan administration. A multiple-employer plan maintains separate accounts for each employer so that contributions received provide benefits only for employees of the contributing employer. However, like multi-employer plans, multiple-employer plans are classified as DC or DB plans based on the economic substance of the plan.

State plans

State plans are those plans established by legislation to cover all entities (or all entities in a particular category, for example, a specific industry) and are operated by national or local government or by another body that is not subject to control or influence by the reporting entity. An example of a state plan in Canada is the Canada Pension Plan.

State plans are also classified as DC or DB plans depending on the entity's obligation under the plan. Many state plans are funded on a 'pay-as-you-go basis' and an entity's only obligation is to pay

contributions as they fall due. Also if the entity ceases to employ members of the state plan, it will have no obligation to pay the benefits earned by its own employees in previous years. For this reason, state plans are normally DC plans. However, when a state plan is a DB plan, an entity accounts for the plan as a multi-employer plan (see above). As sufficient information is usually not available, this means that contributions are only recognized as they become due.

Insured benefits

An entity may pay insurance premiums to fund a P&OPEB plan. The entity treats such a plan as a DC plan unless the entity will have (either directly, or indirectly through the plan) a legal or constructive obligation to pay the employee benefits directly when they fall due or to pay further amounts if the insurer does not pay all future employee benefits relating to employee service in the current and prior periods.

Where an insurance policy is in the name of a specified plan participant or a group of plan participants and the entity does not have any legal or constructive obligation to cover any loss on the policy, the entity has no obligation to pay benefits to the employees and the insurer has sole responsibility for paying the benefits. The payment of fixed premiums under such contracts is, in substance, the settlement of the employee benefit obligation, rather than an investment to meet the obligation. Consequently, the entity no longer has an asset or a liability. Therefore, an entity treats such payments as contributions to a DC plan.

However, where an entity funds a post-employment benefit obligation by contributing to an insurance policy under which the entity (either directly, indirectly through the plan, through the mechanism for setting future premiums or through a related party relationship with the insurer) retains a legal or constructive obligation, the payment of the premiums does not amount to a DC arrangement. Instead, the arrangement is accounted for as a DB plan.

1.4 Key differences in accounting for P&OPEB plans in Canada

As indicated in Section 2.3.2.3 of this report, legacy Canadian GAAP has been replaced over a period of years. For financial years commencing prior to January 1, 2015, rate-regulated entities were able to use Part V of the CICA Handbook – Accounting: Pre-changeover accounting standards (“legacy Canadian GAAP”) because the Accounting Standards Board (“AcSB”) deferred the mandatory changeover date for first-time adoption of IFRS by entities that have activities which are subject to rate regulation. However, the deferral has now come to an end and entities with such activities are required to move away from legacy Canadian GAAP for interim and annual financial statements relating to annual periods beginning on or after January 1, 2015. As such, for financial years beginning on or after January 1, 2015, Canadian rate-regulated entities mainly apply the following accounting frameworks in preparing their general purpose financial statements:

- a) Part I of the CICA Handbook – Accounting: International Financial Reporting Standards (“IFRS”);

- b) Part II of the CICA Handbook – Accounting Standards for Private Enterprises (“ASPE”); and
- c) US GAAP.

Including those rate-regulated entities that are currently in the process of moving away from legacy Canadian GAAP, all four accounting frameworks have been used by utilities that are regulated by the OEB for both financial and regulatory reporting purposes. There are also a few instances of small First Nations utilities, the IESO and a cooperative that use either Canadian GAAP applicable to not-for-profit enterprises or Canadian Public Sector Accounting Standards – for the most part, the accounting requirements for retirement benefits under the Canadian Public Sector Accounting Standards are similar to legacy Canadian GAAP.

All of the above accounting frameworks require use of the *accrual basis* of accounting for financial reporting.

1.4.1 Accounting differences for defined contribution plans

IFRS, ASPE, legacy Canadian GAAP and US GAAP all have similar accounting treatment for both defined contribution plans and those defined benefit plans that are accounted for as defined contribution plans. The accounting is relatively straight forward. Contributions are recognized as a cost when they become due and the recognized amount is allocated between operating and capital expenditures. No additional accounting implications arise.

1.4.2 Accounting differences for defined benefit plans

The accounting for DB plans under IFRS, ASPE, legacy Canadian GAAP and US GAAP is conceptually similar in that all four accounting frameworks require the recognition of the actuarial present value of the benefit obligation, net of the value of the related plan assets, on the statement of financial position. However, although the underlying concepts are similar, there are significant differences in the detailed application of the accounting requirements within each of these frameworks. The following accounting differences are particularly significant and are discussed further:

a) *Funded status of plans*

Under IFRS, ASPE and US GAAP, the net funded status (i.e., the extent to which fund assets exceed or are less than the obligation) of a DB plan is recognized in full in the statement of financial position. This is due to the fact that all actuarial gains and losses and past service costs are immediately recognized either in profit or loss or in Other Comprehensive Income (“OCI”).

On the other hand, under legacy Canadian GAAP, balances relating to unamortized actuarial gains and losses and unamortized past services costs are not recognized in the statement of financial position, but are tracked outside of the books of account. As such, the net funded status of the plan is not fully recognized in the statement of financial position. However, the annual

amortization of the unrecognized amounts (using methods such as the corridor method – see further below) results in the amortized portion being recognized in operating and capital expenditures.

Note however that unlike the other accounting frameworks, ASPE includes a practical expedient for measuring the DB obligation. For those DB plans that have a valuation for funding purposes, the obligation can be measured using either that valuation or one prepared for accounting purposes (the same choice must be applied to all such plans of an individual employer). For plans that do not have a funding valuation, the obligation is required to be measured using an accounting valuation.

b) Use of deferral or smoothing mechanisms

Accounting standards recognize that accounting for DB plans often results in volatile fluctuations in the value of the liability and the related expense. This volatility is the result of an unavoidable inability to accurately predict future events in making period-to-period measurements. It is also due to the fact that actuarial assumptions are projected over many years (often until the death or settlement of the obligation due to the last pensioner) and that, in the long term, it is possible that losses incurred in one period may be offset by gains made in a future period and vice-versa. To diminish such volatility in financial reporting, some accounting standards permit an element of smoothing or deferred recognition of certain P&OPEB costs. However, the smoothing or deferral methods under the various accounting frameworks are not always the same.

Deferral of actuarial gains and losses

Under both legacy Canadian GAAP and US GAAP, changes in actuarial assumptions (e.g., the discount rate used to determine the present value of the pension obligation) and fluctuations in market rates may result in increased or decreased P&OPEB costs recognized in the net income of future periods. Entities have an accounting policy choice in recognizing the P&OPEB costs in net income. An entity has a choice of one of three methods:

- Recognize all the amounts immediately in income;
- Defer all amounts and smooth them through application of the corridor method. The corridor method requires recognition of a minimum amount for the DB obligation, i.e., amounts greater than 10% of the DB obligation or 10% of plan assets at the beginning of each year are amortized (and recorded as operating and capital expenditures) over the average remaining expected period of service of the employees. Note that when applying the corridor method, actuarial gains and losses that are within the 10% corridor are not amortized but are only recognized when the obligation due to the last member of the plan is settled, the plan no longer has active employees or the plan ceases to exist; or
- Apply another systematic amortization method that results in faster recognition than the corridor method.

Under IFRS, all actuarial gains and losses are recognized immediately in Other Comprehensive Income (like US GAAP), but the amounts are not recycled to the income statement (unlike US GAAP). As such, under IFRS, actuarial gains and losses immediately impact an entity's total equity but the amounts never impact the income statement (unless the amounts are capitalized as part of the cost of an asset and find their way into income through depreciation expense). However, an entity may leave the accumulated amount in OCI or reclassify the amount to retained earnings or another category within equity.

Under ASPE, no deferred recognition or smoothing mechanisms are permitted and thus actuarial gains and losses are immediately recognized in net income as incurred. As such, the net income reported under ASPE is potentially much more volatile than net income reported under legacy Canadian GAAP, US GAAP and IFRS.

Market related values

Legacy Canadian GAAP, US GAAP, IFRS and ASPE all measure plan assets at fair value determined as at the reporting date of the financial statements. As the funded status of a plan is recognized in full under IFRS, ASPE and US GAAP, this means that changes in the fair value of plan assets have an immediate impact on the entity's reported shareholders' equity.

However, under legacy Canadian GAAP and US GAAP, in determining the minimum amount of amortization of net actuarial gains and losses to be recognized using the corridor method, an entity has a choice to use either fair value or market-related values. The use of the market-related values provides additional smoothing of DB costs arising from the impact of changes in the fair value of plan assets. A market-related value is a calculated amount that recognizes changes in the fair value of assets in a systematic and rational manner over a period not exceeding five years. Different ways of calculating market-related value may be used for different classes of assets. After a market-related value has been calculated, the actuarial gain or loss not yet reflected in the market-related value of plan assets is not required to be amortized; that part of the actuarial gain or loss is only amortized over future periods when it is included in the market-related value of plan assets in the future. As such, by combining the corridor method with the use of market-related values, an entity can significantly reduce the volatility in net income due to actuarial and investment experience.

Past service costs

Under IFRS and ASPE, past service costs are immediately recognized in net income as they arise.

On the other hand, both legacy Canadian GAAP and US GAAP defer the impact of past service costs on net income. Under US GAAP, past service costs are initially fully recognized and deferred in OCI, and then subsequently amortized on a straight-line basis to net income over the expected average remaining service lives of active employees. Under legacy Canadian GAAP, however, past service costs are initially not recognized in the statement of financial position, but are tracked outside of the books of account (i.e. unrecognized amounts). Thereafter, past service

costs are recognized in the statement of financial position and net income on a straight-line basis over the expected average remaining service lives of active employees.

c) Expected return on plan assets

Legacy Canadian GAAP, US GAAP, IFRS and ASPE all recognize that, for funded plans, the periodic cost of P&OPEB plans is reduced by investment gains arising from the performance of plan assets. Under ASPE, the actual return on plan assets (as opposed to the expected return) is immediately recognized in the net income for each period. Unlike ASPE, legacy Canadian GAAP, US GAAP and IFRS require the performance of plan assets to be forecast at the beginning of the year (so called “the expected return on plan assets”). However, different methods are used to forecast the expected return.

Under IFRS, the expected return on plan assets is calculated using the same rate as the discount rate used to determine the benefit obligation. As such, the rate of expected return on the plan assets cannot be higher (or lower) than the rate used to discount the benefit obligation that the assets are intended to cover. Further, the return on plan assets is forecast based on the fair value of the plan assets as determined at the start of the annual reporting period taking into account any changes in the plan assets as a result of contributions and benefit payments. Note that use of fair value of plan assets in calculating the expected return for each annual period makes the calculated amount more vulnerable to volatility from changes in the fair value of the underlying plan assets.

Note also that, under IFRS, the difference between the actual return on plan assets (net of any costs of managing the plan assets), and the calculated expected return on plan assets is included in OCI together with any actuarial gains and losses (i.e. “remeasurement adjustments”). This difference will never be recognized in the income statement.

Two key differences exist when the above ASPE and IFRS requirements for the return on plan assets are compared to legacy Canadian GAAP and US GAAP:

- i) Under legacy Canadian GAAP and US GAAP, the expected return on plan assets is determined by an actuary and management based on their best estimate of future long-term rates of return. The expected rate of return that is used is not required to be the same as the rate used to discount the DB obligation; and
- ii) Under legacy Canadian GAAP and US GAAP, the expected return on plan assets is calculated based on either the fair value of plan assets (i.e. like IFRS) or, if the entity chose to use market-related values for amortizing actuarial gains and losses - see discussion above - market-related values (i.e. unlike IFRS). As previously discussed above, market-related values incorporate a smoothing mechanism that can significantly reduce volatility in net income from changes in the value of the underlying plan assets.

In summary

The differences among the various accounting frameworks can have a significant impact on the DB cost that is reported by an entity during each period, and can significantly impact comparison and

benchmarking analyses among utilities. The result of having more than one accounting framework in use in Ontario is a significant increase in complexity when assessing the reasonableness of DB costs calculated in accordance with accounting standards, as compared to when they are calculated in accordance with the funding contribution rules of the PBA. Variations in the accounting treatment of P&OPEB costs as determined by the various accounting frameworks that are used by regulated utilities would pose challenges for the OEB in applying a simple and consistent cost recovery method for P&OPEB costs. In Appendix G we have illustrated, by way of a simplified example, how the accounting framework that is selected by an entity can impact its reported P&OPEB expense.

1.5 Use of regulatory deferral and variance accounts in accounting for P&OPEB costs in general purpose financial statements

The regulated rates charged to customers can result in the amount of P&OPEB costs that is included in rates being different from the expense that is recognized in general purpose financial statements. Some rate regulators do not make a determination on true-up treatment of any variance between test year forecast and actual spending (such as operating and capital expenditure) in a cost of a service rate proceeding. However, some rate regulators may make exception for P&OPEB related costs and require that the difference between the amount that is included in rates and the expense recognized using the accrual basis of accounting be recorded in a deferral or variance account. In such cases, the amounts that are recorded in deferral or variance accounts are subsequently collected from (or refunded to) customers in future periods.

As detailed in Section 2.3.5, in Ontario the decision whether to grant generic deferral or variance accounts to capture differences between the P&OPEB costs included in rates and the actual amounts incurred is that of the OEB. The OEB may wish to seek input through the Consultation whether it is appropriate to grant a generic deferral and/or variance account for P&OPEB costs and to consider how the transition to the methods of recovering P&OPEB costs identified in this report, if adopted, will be handled.

Regulated entities that prepare their general purpose financial statements in accordance with legacy Canadian GAAP and ASPE, as well as those regulated entities that are eligible to elect to apply the requirements of IFRS 14 and elected to do so when they adopted IFRS (see further details below), generally all recognize regulatory deferral and variance accounts in accordance with the accounting principles set out in ASC 980. The requirements of ASC 980 for P&OPEB costs are detailed in Section 2.4 and Section 3.5 of this report, respectively.

Regulatory deferral accounts under IFRS

Historically, the established practice of almost all entities that report under IFRS has been to eliminate regulatory deferral account balances when IFRS is adopted and not to recognize such

balances when general purpose financial statements are prepared. Thus, regulatory deferral account balances have not been recognized in IFRS financial statements and there has not been significant diversity in practice. However, despite this apparent consistency, different views emerged when other jurisdictions (including Canada) were considering the adoption of IFRS by rate-regulated entities. As a result, the AcSB permitted rate-regulated entities to defer the adoption of IFRS pending the outcome of the IASB's discussions on this issue. Some Canadian regulated entities (including a small number of utilities that are regulated by the OEB) however elected to go ahead and adopt IFRS without awaiting the outcome of the IASB's discussions; generally, like most other IFRS reporters, such entities also did not recognize regulatory deferral account balances in their IFRS financial statements.

On January 30, 2014, the IASB published IFRS 14, *Regulatory Deferral Accounts* ("IFRS 14"). IFRS 14 permits entities with regulated activities that are *first-time adopters* of IFRS to recognize and measure regulatory assets and liabilities in accordance with their previous GAAP. As such, a utility that adopts IFRS for the first time is now able to continue its previous practice under legacy Canadian GAAP and recognize regulatory deferral account balances (generally, this is also in accordance with ASC 980). It is important to note that IFRS 14 is not available for use by an entity that has already adopted and reported its general purpose financial statements in accordance with IFRS. As such, the few Ontario utilities that were already reporting under IFRS before January 30, 2014 are now not able to apply IFRS 14 and recognize their regulatory deferral account balances.

The main features of IFRS 14, which is mandatorily effective for annual periods beginning on or after January 1, 2016¹ but is available for earlier application, include the following:

- 1) By electing to apply the requirements of IFRS 14 when it adopts IFRS, a regulated entity is able to continue to use, in its first and subsequent IFRS general purpose financial statements, its previous GAAP accounting policies for the recognition, measurement, impairment and derecognition of regulatory deferral account balances without specifically considering the requirements of other relevant IFRS authoritative literature. As such, a first-time adopter can now elect to continue to recognize and measure regulatory deferral account balances in accordance with its previous practice under legacy Canadian GAAP.

In making the decision on whether to elect to apply the requirements of IFRS 14, it is important to also note that all specified requirements for reporting regulatory deferral account balances, and any exceptions to, or exemptions from, the requirements of other Standards that are related to those balances, are contained within IFRS 14 instead of within those other Standards. In the absence of any such exception, exemption or additional requirements, other Standards shall

¹ In Canada, the Accounting Standards Board ("AcSB") had deferred the mandatory date for first-time adoption of IFRS by entities with qualifying rate-regulated activities to January 1, 2015. When the IASB published IFRS 14, the AcSB decided against further extending the deferral. As such, Canadian regulated utilities that had deferred the changeover to IFRS mandatorily adopted IFRS with effect from January 1, 2015, and were able to apply IFRS 14 as part of their transition to IFRS.

apply to regulatory deferral account balances in the same way as they apply to assets, liabilities, income and expenses that are recognised in accordance with other Standards.

- 2) IFRS 14 requires entities to present regulatory deferral account balances as separate line items in the statement of financial position, and to present movements in those account balances as separate line items in the statement of profit or loss and other comprehensive income. Although a regulated entity that adopts IFRS for the first time is now permitted to recognize, measure, impair and derecognize its regulatory deferral account balances in accordance with legacy Canadian GAAP, the entity is required to comply with the presentation requirements of IFRS 14. In most instances, this requires changes to the regulated entity's presentation under Canadian GAAP. Specifically, under IFRS 14:
 - a) An entity is required to present separate line items in the statement of financial position for the total of all regulatory deferral account debit balances and the total of all regulatory deferral account credit balances. The separate line items are distinguished from the assets and liabilities that are presented in accordance with other Standards by the use of sub-totals, which are drawn before the regulatory deferral account balances are presented. When an entity presents current and non-current assets, and current and non-current liabilities, as separate classifications in its statement of financial position, it is prohibited from classifying the totals of regulatory deferral account balances as current or non-current;
 - b) An entity is required to present, in the other comprehensive income section of the statement of profit or loss and other comprehensive income, the net movement in all regulatory deferral account balances for the reporting period that relate to items recognised in other comprehensive income. Separate line items are used for the net movement related to items that, in accordance with other Standards will not be reclassified subsequently to profit or loss and those that will be reclassified subsequently to profit or loss when specific conditions are met; and
 - c) An entity is required to present a separate line item in the profit or loss section of the statement of profit or loss and other comprehensive income, or in the separate statement of profit or loss, for the remaining net movement in all regulatory deferral account balances for the reporting period, excluding movements that are not reflected in profit or loss, such as amounts acquired. This separate line item is distinguished from the income and expenses that are presented in accordance with other Standards by the use of a sub-total, which is drawn before the net movement in regulatory deferral account balances.
- 3) IFRS 14 requires specific disclosures to identify the nature of, and risks associated with, the rate regulation that has resulted in the recognition of regulatory deferral account balances in accordance with the Standard. As such, if a rate-regulated entity elects to apply IFRS 14, it is required to disclose additional information that enables users of its general purpose financial statements to assess the effects of that rate regulation on the entity's financial position, financial performance and cash flows.

In summary, a Canadian regulated entity that elects to apply IFRS 14 when it adopts IFRS will recognize, measure, impair and derecognize its regulatory deferral account balances in accordance with previous its practice under legacy Canadian GAAP (generally, this is also in accordance with the accounting principles set out in ASC 980 – see Section 2.4 and Section 3.5 of this report). However, presentation differences will arise when reporting under IFRS and additional specific disclosures will also have to be included in the general purpose financial statements.

Appendix D – Trends

The global economy along with changing demographics has led regulators around the world to re-think and adjust the frameworks they have created to better promote fair, affordable and sustainable pension plans.

Pension reform trends globally

Almost every region in the world has been in the process of reforming its pension system. However, the motivations for reform and the particular avenues that it has taken differ dramatically from one country to another:

- In much of Asia, pension reform debates are dominated by concerns about broadening coverage and improving benefits.
- In the economies in transition from socialism, the reforms are largely motivated by the need to adjust pension programs and administering institutions to a market economy.
- Many Latin American reforms are motivated in part by a desire to insulate the pension system from political interferences and to improve the quality of service to pension system participants.
- Reform debates in North America, Japan and Western Europe, on the other hand, have tended to focus on dealing with the increasing costs of an ageing population.

In North America, Japan and Western Europe, DB pensions have a strong historical presence as part of the employer’s compensation package. However, it has become increasingly difficult for employers to afford these “promised” pensions, leading to a shift away from DB pensions in these regions.

Pension reform trends in the UK

Employers in the UK have been moving away from DB pensions. The proportion of DB plans which are closed to both new members and future accrual has risen from 7% in 2009 to 39% in 2014¹. DB pension plans of utilities regulated by Ofgem are all closed to new entrants. The majority of DB plans in the UK that have not been closed are now public sector plans with most private sector employers providing DC benefits for future accrual and/or newly hired employees.

In the UK, compulsory automatic enrolment into pension plans began in October 2012 for the very largest employers. By law, most workers aged between 22 and State Pension Age will have to be automatically enrolled into a pension plan meeting certain minimum contribution or benefit

¹ 40th NAPF Annual Survey

requirements. Workers can opt-out of this arrangement, but only after they have been automatically enrolled. Employers will not be allowed to encourage opt-outs. This change will be phased in over five years from October 2012, with the largest employers having to automatically enrol their employees first.

Recent pension reforms in Canada Shift of risk and funding towards employees

New Brunswick (in force, 2012)

- Introduced Shared Risk Pension Plan (“SRP”), adopted by several public & private sector entities
- Option to convert DB plans to SRP
- Limited variation in contributions, within a specified range
- Pre and post conversion benefits can be curtailed

Ontario public sector (proposed/in force, 2012-2015)

- Pooled asset management for broader public sector pensions
- Freezing contribution rates in certain JSPPs
- Solvency funding relief for plans that improve sustainability
- Encouraging plans to move toward a JSPP model (specific initiative in electricity sector)
- Special Advisor report on Report on the Sustainability of Electricity Sector Pension Plans

Federal public service (in force, 2013)

- Retirement age: 60→65
- Increase of employee contribution rates
- Move to 50/50 cost sharing

Alberta public sector (proposed 2013, not carried through on the order paper 2014)

- Cap on contribution rates
- Freezing benefit improvements and reduced cost-of-living adjustment
- Reductions of early retirement benefits

Pension trends in Canada

As with the rest of the world, employers in Canada have been moving away from DB pensions and OPEB over the last 20 years. Historically, this movement has been quite limited in the public sector as compared to the private sector. Over the period from 1992 to 2014, the percentage of pension plan members in the public sector who participate in pure traditional DB pension plans has declined only slightly, from 96% to 94%, compared to a decline from 84% to 47% of pension plan members in traditional DB plans in the private sector over the same period¹. In the private sector, the most significant trend has been for employers to freeze their DB pension plans, either:

- For existing employees only, creating a separate DC plan for new employees; or
- To future build-up of benefits for current DB members, moving to DC benefits for all employees’ future service.

¹ Source: Statistics Canada, CANSIM 280-0016; “Pure traditional DB pension plans” exclude pension plans which may offer DC pensions for some employees, for example for new employees only.

Though statistics are not readily available, recent surveys of Canadian employers suggest similar changes in the provision of DB OPEB benefits.

Recent economic and demographic changes, leading to soaring DB costs, coupled with pressure on public finances, have attuned Canadian public sector bodies to the challenges posed by guaranteeing DB benefits for employees, and public sector pension reform is underway across the country.

Federal

Effective in 2013, the federal government has implemented changes to DB pensions for federal public service employees including increasing the retirement age from 60 to 65, and increasing contribution rates to move to a 50/50 employee cost sharing model by the year 2017. Similar changes were applied to the pension plan for MPs.

The federal government had also required that the age of eligibility for Old Age Security (OAS) pension and the Guaranteed Income Supplement (GIS) gradually increase from 65 to 67 over six years, starting in April 2023. The ages of eligibility for the Allowance and the Allowance for the Survivor were to also gradually increase from 60 to 62. Those born before April 1, 1958 would not be affected by these changes. However, the recent 2016 Federal Budget reversed these changes and confirmed that the eligibility age for Old Age Security benefits, as well as the Guaranteed Income Supplement, will be lowered back to 65 from 67.

The Canada Pension Plan has been gradually phasing in changes since 2011, which include increased penalties for early retirement, and increased enhancements for late retirement. Similar changes to the Quebec Pension Plan are also being phased in.

British Columbia

In the 2000s the Government of British Columbia implemented changes to its public sector pension system to make the indexing of pensions conditional on the pension plan's performance. British Columbia also moved to a structure where both employees and employers would be required to fund deficits, and where the pension plans are jointly trustee. The result is a benefit plan that falls between a DB and a DC pension.

New Brunswick

The Government of New Brunswick implemented pension reform in May 2012 which has been well-received by employers in the province's public sector, and has also been adopted by some private sector employers. The new legislation introduced the Shared Risk Pension Plan ("SRP") model, and provides the option to convert a traditional DB pension plan to an SRP. A number of New Brunswick employers have converted their DB plans to SRPs including several plans covering unionized employees, and plans for employees of New Brunswick Power Corporation, the Power Commission of St. John, City of St. John, the City of Fredericton and the province of New Brunswick. Designed to improve upon the renowned Dutch pension system, the SRP model fixes employer and employee contribution rates up front.

Contributions can only fluctuate within a limited range, and benefits can fluctuate depending on the performance of plan investments. The SRP allows for cuts to DB benefits already earned, including those already being paid to retirees.

Alberta

In September 2013, the Government of Alberta had announced that it would pass a law to impose a number of changes to its four public-sector pension plans, which would have included a cap on total contribution rates for the government and its employees. Reductions were also to be made to early retirement benefits and cost of living adjustments. With the change in government in Alberta, these specific measures will not be moving forward, and at the time of writing it is unclear whether changes to public sector pensions will remain a priority for the Alberta government as they have said that the government will not reintroduce the pension bills that included the proposed changes.

Further, KPMG's review of the regulatory practices in other jurisdictions identified that a regulated entity appealed in the Court of Appeal of Alberta a decision by the Alberta Utilities Commission ("AUC") which had denied the regulated entity permission to include certain pension costs in the estimates of revenue requirements. The denied pension costs related to pensions having 100% cost-of-living adjustment ("COLA"), to a maximum of 3%. Having regard to arguments made (including with respect to the need to remain competitive, the vested expectation of employees, and industry standards for pension benefits), AUC had concluded that the evidence did not support a finding that the regulated entity's practice for COLA is an acceptable standard practice. The appeal was dismissed by the Court and, therefore, the ruling by AUC remained in effect.¹ However, the regulated entity sought leave of the Supreme Court of Canada to appeal this ruling² and leave to appeal was granted. In December 2014, the appeal was heard by the Supreme Court of Canada together with another case in Ontario; the Supreme Court of Canada dismissed the appeal³.

Nova Scotia

KPMG's review of the regulatory practices in other jurisdictions identified that a regulated entity provided a SERP to employees who earn more than approximately \$150,000 per year. The contributions are wholly funded by the regulated entity and the pension benefits are secured by a letter of credit that is provided by the regulated entity. The Nova Scotia Utility and Review Board ("UARB") concluded that payments for the letter of credit are an unnecessary expense and

¹ Memorandum of Judgment in the Court of Appeal of Alberta, *Atco Gas and Pipelines Ltd. v Alberta (Utilities Commission)*, 2013 ABCA 310 filed on September 23, 2013

² *ATCO Gas and Pipelines et al v. Alberta Utilities Commission*, [2013] A.J. No. 989 (C.A) upholding Alberta Utilities Commission Decision No. 2011-391. ATCO applied for leave to appeal to the Supreme Court of Canada on November 21, 2013, [2013] S.C.C.A. No. 459.

³ Judgments of the Supreme Court of Canada, *ATCO Gas and Pipelines Ltd. V Alberta (Utilities Commission)*, 2015 SCC 45, [2015] 3 SCR 219 dated September 25, 2015

disallowed that amount from revenue requirement. UARB also concluded that it is unreasonable that the most highly paid employees working for the regulated entity make no contribution to the SERP; as such it ordered that 50% of the contributions made by the regulated entity to the SERP be deducted from revenue requirement (i.e. so that customers do not pay for this benefit). UARB also expects the regulated entity to take additional steps to improve contributions to, and the funding of, its pension plan for the other employees.¹

Ontario

Several pension-related Ontario government initiatives are currently underway. Certain outcomes of these initiatives could directly impact public sector pension costs and require adoption of a funding contribution basis for financial reporting purposes instead of the accounting accrual basis for some electricity sector employers.

In its 2014 budget, the government released details on the new Ontario Retirement Pension Plan (“ORPP”), which is to become effective starting in 2017 and will provide pensions to Ontarians who do not have an employer-sponsored pension plan that meets minimum requirements for benefit adequacy, requiring contributions of 1.9% of pay up to \$90,000 from each of employers and employees. The defined benefit pension plans provided in the electricity sector would be expected to result in an exemption of the employers in that sector.

In its 2012 Budget, the Government of Ontario announced its intention to create a framework which would facilitate pooled asset management for the province’s public sector pension funds. As a first step in creating this framework, the government appointed Bill Morneau as an expert advisor. Mr. Morneau released a report in late 2012, which recommended proceeding with asset pooling for pension plans in the public sector, to create a \$50-100 billion “super-fund” entity and the 2015 Budget introduced legislation to create a new asset management corporation to manage the fund. The super-fund, which could include \$14 billion in assets attributed to electricity sector pension plans (including Hydro One and OPG), is expected to increase diversification and investment opportunities, enhance governance and provide economies of scale for the participating pension plans. As a result, long-term investment returns for these plans would be expected to increase, reducing pension costs. The largest Ontario jointly-sponsored pension plans (JSPPs), including OMERS, would not be included in the super-fund. The outcome of the Morneau report is not expected to have an impact on funding or accounting methodology but could impact the level and volatility of costs for affected pension plans, as it would result in the pooling of investments only, keeping the plans separate from a benefits perspective.

In the 2013 Ontario Budget, in addition to announcing its intention to proceed with the creation of the super-fund, the government brought forward additional items pertaining to pensions in the public sector, which it has continued to move forward in its 2014 and 2015 Budgets. These include:

¹ Decision, 2012 NSUARB 227, M04972 dated December 21, 2012

- freezing contribution rates in the large JSPPs, including OMERS, until 2017-18;
- encouraging public sector single-employer pension plans to adopt changes that improve sustainability in exchange for temporary solvency funding relief;
- encouraging public sector single-employer pension plans to move towards a JSPP model. In the electricity sector in particular, the government stated its continued commitment to eliminating barriers to the creation of new JSPPs by creating a legislative framework for conversion; and
- creating a working group composed of employee and employer representatives in the electricity sector to promote common understanding of the pension challenges in this sector and move towards more sustainable models. In March 2014, the Special Advisor to the Ontario Ministry of Finance released a “Report on the Sustainability of Electricity Sector Pension Plans” as part of this initiative. The report includes a recommendation to move to 50/50 cost-sharing for pension plan contributions and establishment of contribution rate ceilings, and recommends continuation of the JSPP, temporary solvency relief and pooled asset management initiatives as they relate to the electricity sector.

As with the super-fund, the above initiatives seek to reduce costs and enhance sustainability for public sector pension plans. The outcomes may impact levels of pension costs, how those costs are determined and how they are allocated between employers.

The 3rd item, a move toward a JSPP model, is expected to have a particular impact on accounting methodology. At the date of this report, draft proposed regulations are available. However, if JSPPs are formed from pension plans that are currently single-employer plans, this will likely result in DC accounting treatment for these pension plans, but will not, on its own, eliminate the potential escalation of costs. The Ontario Government is currently considering whether a newly formed JSPP should be eligible to receive an exemption from solvency funding requirements, which could result in reduced costs for single-employer plans that convert.

Appendix E – Industry Oversight

Introduction

Appendix D addresses control of pension plan assumptions and governance for DB pension plans in Ontario. This appendix addresses the oversight of P&OPEB plans of the Ontario utilities rate-regulated by the OEB by oversight bodies external to the utilities' management.

KPMG reviewed the roles of various parties providing oversight in order to identify gaps or overlaps between their roles with respect to P&OPEB costs. This appendix summarizes the results of that work. OEB staff participated in some of the key interviews conducted by KPMG.

The first section addresses pension plans registered with Financial Services Commission of Ontario ("FSCO") pursuant to the PBA ("registered pension plans") and with the CRA. The principal parties providing oversight in various capacities for these plans are FSCO, the independent financial statement auditors, the CRA and the OEB. For registered pension plans that are DB plans, the actuary provides independent input in preparing and certifying the funding contribution calculations in accordance with accepted actuarial practice in Canada. This oversight framework is discussed in more detail below under the heading "Registered Pension Plan Oversight".

OPEB plans and SERPs are not registered plans. Oversight for them is provided by the independent financial statement auditors, the CRA (where applicable) and the OEB, as well as the actuary in the case of OPEB plans and SERPs that are DB plans. This oversight framework is discussed in more detail below under the heading "OPEB Plan and SERP Oversight".

The final section of this appendix describes the guidelines and standards applicable to oversight parties.

Registered Pension Plan Oversight

General

The key stakeholders that are participating in various ways in the operation and oversight of DB registered pension plans in Ontario are shown in schematic form in Appendix D. The schematic for a Single-Employer DB Pension Plan and for the OMERS multi-Employer Pension plan are provided.

Note that the relationships among the participants are relatively complex.

Summary

The oversight provided by the various parties does not appear to overlap to any significant degree. FSCO is the principal oversight agency responsible for ensuring compliance with the PBA. As the mandate of FSCO does not directly address whether the P&OPEB costs in the electricity and natural

gas sectors are reasonable, there is unlikely to be significant overlap between the work of FSCO and OEB.

The oversight work of parties other than the OEB provides some level of assurance to the OEB that the information provided to the OEB is reliable and accurate. For instance the financial statement auditors provide assurance that the values reported in financial statement statements and the notes to the financial statements are reliable. For DB plans, the actuary's reports provide the OEB with some assurance as to the reasonableness of underlying assumptions as well as an understanding of the methods and assumptions used, and are also relied upon by FSCO, the CRA and the auditors.

Role of FSCO¹

FSCO's responsibilities relating to pension plans include:

- Responding to inquiries and complaints from pension plan members.
- Investigating alleged breaches of the Pension Benefits Act (PBA) and taking enforcement action when required.
- Administering the Pension Benefits Guarantee Fund (PBGF) and collecting PBGF assessments from plan sponsoring employers.
- Monitoring pension plans and pension funds to ensure they are being administered, invested and funded in compliance with legislated requirements.
- Registering new pension plans and pension plan amendments.
- Processing required filings and applications from plan administrators.
- Regulating certain multi-jurisdictional pension plans.

FSCO is moving toward a risk-based framework for pension plan supervision. It considers a broad universe of risk factors in areas such as administration, governance, and sponsor related risks. The goal is for the framework to provide a base level of regulation across all pension plans. The framework includes monitoring of key risk indicators, improving dialogue with stakeholders, and promotion of best-practices.

For DB registered pension plans, FSCO considers the reasonableness of the assumptions used to value the pension liabilities for funding contribution calculations, particularly the discount rate.

FSCO has periodic reporting requirements that plan sponsors must meet. These include preparation of audited financial statements for the pension fund and, for DB registered pension plans, preparation of the annual or triennial (valuations are required annually if the solvency ratio of a plan is less than 85%) funding valuation report which contains the minimum and maximum funding contributions. The reported information provides a base level for monitoring registered pension plans.

¹ Source: FSCO website confirmed in meeting with FSCO staff.

Above this base level monitoring, FSCO focuses resources on pension plans that exhibit the greatest amount of risk. FSCO generally does not look through to the plan sponsor so as to rely on their financial strength or assess the financial viability of the plan sponsor unless or until FSCO becomes aware that the sponsor is in financial difficulties.

Role of Ontario Energy Board

The mandate of the OEB is to oversee Ontario's electricity and natural gas sector through effective, fair and transparent regulation and in accordance with the objectives set out in the governing statutory framework. One of the objectives is to facilitate the maintenance of a financially viable electricity and gas industry in Ontario. The OEB's mandate is determined by the provincial government and is embodied in legislation, regulation and directives. Its mission is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists customers to obtain reliable energy services that are cost effective.

OEB rate-regulates 72 electricity Local Distribution Companies ("LDCs") most of whom are members of OMERS, and utilities which sponsor single-employer defined benefit pension plans in the transmission, distribution and generation of electricity, including Hydro One and Ontario Power Generation. It also regulates the gas distribution sector which includes two main players who sponsor single-employer defined benefit pension plans (Enbridge Gas Distribution and Union Gas) as well as the IESO.

Rates for natural gas and electricity distributors and transmitters, and payments for Ontario Power Generation, are approved by the OEB from a revenue requirement based on forecast costs. Pension costs are a key component of these cost forecasts.

Roles of Other Oversight Parties

The role of the independent financial statement auditor has been described above. In summary the auditor provides a level of assurance that the pension related values reported in the financial statements are reliable and accurate. The OEB relies on many of the pension related values reported in these statements and notes and requires utilities to reconcile values used in their rates applications to the numbers in the statements and notes.

For registered DB plans, the work of the actuary is seen by the OEB through the actuarial funding valuation report prepared at least every three years to meet PBA requirements. The actuarial funding valuation report provides significant understanding of the basis of calculation of pension related values relevant to a rates proceeding and the actuary's certification that the amounts are determined in accordance with accepted actuarial practice and consequently a level of assurance concerning the reasonableness of those values.

The role of CRA is to ensure the registered pension plan meets the requirements of the Income Tax Act. Funding contributions to registered pension plans and investment earnings on those contributions are tax-exempt, and the utility's contributions can be a major component of cost claimed by a utility as a deduction from income for purposes of calculating taxable income. For DB registered pension plans, the CRA relies upon the funding valuation report prepared by the actuary

which provides the calculation of the maximum tax-deductible contribution in accordance with the Income Tax Act.

OPEB Plan and SERP Oversight

OPEB plans and SERPs are not registered with FSCO under the PBA. Accordingly, FSCO has no role with respect to their monitoring, and the utility is generally not required to set funds aside in advance to underwrite its obligation to pay the agreed benefits to plan beneficiaries in the future.

The OEB nonetheless can gain assurance from the work of other oversight parties as described above including the independent financial statement auditors and the actuaries.

Guidelines and Standards Applicable to Oversight Parties

FSCO is a member of the Canadian Association of Pension Supervisory Authorities (“CAPSA”). CAPSA has published a number of guidelines relating to areas of concern to its members which are considered industry best practices. One of these is Guideline No. 4 that spells out Pension Plan Governance Guidelines. These were published by CAPSA in 2004 and were used as a reference by KPMG in developing the methods of recovering P&OPEB costs and related Information Requirements set out in this report. The scope of Guideline No. 4 includes oversight, management and administration of pension plans to ensure fiduciary and other obligations of plans are met.

Independent financial statement auditors are required to adhere to Generally Accepted Auditing Standards as specified by CPA Canada. Audit firms are subject to practice inspection by their provincial institutes and various sanctions if they fall short on inspection reports with respect to how they conduct audits. CPA Canada, FASB and the International Accounting Standards Board establish the framework of accounting standards to which reported financial information must adhere and to which the independent auditors audit. Failure to conform to the standards can result in a qualified audit opinion – a highly undesirable outcome for any plan sponsor.

Actuaries practicing in Canada are Fellows of the Canadian Institute of Actuaries (“CIA”). The CIA publishes Standards of Practice as well as other guidance material. Actuaries must perform their work in accordance with the CIA Standards of Practice and must be familiar with all other relevant guidance material. Actuaries are also subject to the CIA’s Rules of Professional Conduct, failure to comply with which can lead to disciplinary action by the CIA including fines and suspension or expulsion from the CIA.

Appendix F – Experiences and Practices in Other Regulatory Jurisdictions

1.1 Purpose and objectives

The OEB asked KPMG to conduct a review of the regulatory practices for P&OPEB costs in other jurisdictions that regulate the price of gas and electricity. The particular issues that the OEB sought to establish and understand were:

1. Do other regulators have separate and distinct principles for dealing with P&OPEB costs?
2. Are P&OPEB costs included in the costs that are eligible for recovery from customers in each period? If so, what is the rationale for doing so?
3. How are the P&OPEB costs determined and how do regulators verify that the costs are reasonable?
4. What method is used for including the P&OPEB costs in the rates charged to customers (i.e. accrual, funding, cash cost or settlement basis) and what is the rationale for the selected method and timing of the cost recovery?
5. What oversight role do rate regulators play with regards to P&OPEB plans?
6. Are any incentives provided to reduce P&OPEB costs?
7. Do P&OPEB plans include employees from non-regulated businesses? If so, how does the regulator verify that the P&OPEB costs that are included in rates relate only to the regulated business?

1.2 Review methodology

KPMG applied the following methodology in conducting the review:

- KPMG developed a detailed questionnaire setting out specific questions that were considered important in order to answer the above questions;
- Based on knowledge developed through KPMG's global network, KPMG identified those jurisdictions that set rates based on practices that are similar to those of the OEB. In deciding the jurisdictions to be included as respondents to the questionnaire, KPMG also considered factors such as the size of the utilities in the jurisdiction, the number of regulated utilities that are part of the jurisdiction and the financial reporting framework that is applied by the regulated utilities. The selected jurisdictions were discussed and agreed to by OEB staff;

- The detailed questionnaire was distributed to staff employed by regulators in the selected jurisdictions; and
- The responses to the questionnaires were summarized and, when considered appropriate to confirm an understanding of the responses and relevant regulatory practices, additional follow-up was carried out.

It is important to note the following:

- a) By voluntarily responding to the questionnaire, the respondents (i.e. the regulators and the individual staff members that responded) assumed no responsibility whatsoever to the users of the questionnaire and of this report;
- b) Although generally all the individual staff members that responded have detailed, ongoing working knowledge of the regulatory practices in their jurisdiction, KPMG did not ask them to carry out exhaustive research and analyses of their regulatory practices. As such, it is possible that they may not have reported back all the relevant facts and practices in their jurisdiction. The individual staff members that responded were asked to respond based on their working knowledge, experience and/or understanding of the regulatory practices in their jurisdiction.

1.3 Jurisdictions and Regulators selected for the review

The questionnaire was submitted to regulators in the following jurisdictions:

Canada

- a) **Alberta:** the Alberta Utilities Commission (“AUC”);
- b) **British Columbia:** the British Columbia Utilities Commission (“BCUC”);
- c) **Nova Scotia:** the Nova Scotia Utility And Review Board (“UARB”); and
- d) **Québec:** the Régie de l’énergie (“Régie”).

United States of America

- a) **US Interstate:** the Federal Energy Regulatory Commission (“FERC”);
- b) **Illinois:** the Illinois Commerce Commission (“ICC”); and
- c) **Pennsylvania:** the Pennsylvania Public Utility Commission (“PUC”).

Europe

- a) **Great Britain** (England, Scotland and Wales): Office of Gas and Electricity Markets (“Ofgem”)

Oceania

- a) **Australia:** the Australian Energy Regulator (“AER”); and
- b) **New Zealand:** the Electricity Authority (“EA”).

AUC elected not to respond to the questionnaire as the commission considered itself to be in transition due to the then ongoing revisions to the jurisdiction’s public sector pension framework. Also, at the time of concluding the review, PUC had not provided their responses. For these reasons, the summarized review findings set out below do not include information relating to these two regulatory jurisdictions. However, as identified in Appendix I of this report, AUC permits some of the utilities that it regulates to include P&OPEB costs in rates based on estimated cash payments.

It should also be noted that the extent and detail of responses received from AER and EA was limited and greatly reduced by the fact that these jurisdictions deal primarily with defined contribution pension plans (as opposed to defined benefit pension plans); they stated that regulated entities in their jurisdiction had moved away from defined benefit plans several years ago. Also, AER and EA did not specifically respond to questions relating to OPEB plans.

1.4 Key review findings

The responses to the questionnaire identified the following information that KPMG expects to be of interest and relevance to the OEB as it develops an understanding of how other regulators have responded to P&OPEB issues and challenges in setting rates:

1. Do other regulators have separate and distinct principles for dealing with P&OPEB costs?

Although regulated entities in all the jurisdictions surveyed provide employee benefits through P&OPEB plans (comprising defined benefit plans and/or defined contribution plans), only Ofgem has developed a detailed set of *separate and distinct* principles for dealing with defined benefit pension costs. Ofgem has, however, not developed separate and distinct principles for OPEB costs. The Ofgem principles are listed below. Although Ofgem has developed additional implementation guidance over time, the principles remain unchanged since they were established in 2003.

In order to assess P&OPEB costs in setting rates that are just and reasonable, other regulators place reliance on the same general regulatory principles that are used for assessing any other capital or operating expenditure that is incurred by a regulated entity in their jurisdictions.

The review, however, also identified that in 1993 FERC announced a general policy that provided guidance on the regulatory accounting treatment of P&OPEB costs. The policy was issued and adopted as a general statement of FERC’s policy.

In summary

The key findings identified by the review are:

Regulator	Findings
Ofgem	<ul style="list-style-type: none"> - Detailed set of separate and distinct principles were established for defined benefit pension costs in 2003 (see below); - Additional implementation guidance has been developed over time. Although they have continued to evolve, the principles remain unchanged since 2003; and - No separate and distinct principles were established for OPEB costs.
FERC	<ul style="list-style-type: none"> - No separate and distinct principles; and - General policy on the regulatory accounting treatment of P&OPEB costs was announced in 1993. The general policy is based primarily on the accounting principles used for financial reporting.
Canadian regulators	<ul style="list-style-type: none"> - No separate and distinct principles; and - Generally, regulatory practice can vary from case-to-case.
AER	<ul style="list-style-type: none"> - No separate and distinct principles; and - P&OPEB costs are assessed on a case-by-case basis.
EA	<ul style="list-style-type: none"> - No separate and distinct principles as this jurisdiction deals primarily with defined contribution pension plans.

The separate and distinct principles that were established by Ofgem for defined benefit pension costs are:

Price Control Treatment of Network Operator Pension Costs Under Regulatory Principles¹

Principle 1	<p>Efficient and economic employment and pension costs</p> <p>Customers should expect to pay the efficient cost of providing a competitive package of pay and other benefits, including pensions, to staff of the regulated business, in line with comparative benchmarks.</p>
Principle 2	<p>Attributable to regulated fraction only</p>

¹ *Price Control Treatment of Network Operator Pension Costs Under Regulatory Principles*, Office of Gas and Electricity Markets (Ofgem), London England, pg 6-7 et al, Ref 76/10, update June 22, 2010

	Liabilities in respect of the provision of pension benefits that do not relate to the regulated business should not be taken into account in assessing the efficient level of costs for which allowance is made in a price control.
Principle 3	<p>Stewardship – ante/post investment</p> <p>Adjustments may be necessary to ensure that the costs for which allowance is made do not include excess costs arising from a material failure of stewardship.</p>
Principle 4	<p>Actuarial valuation/scheme specific funding</p> <p>Pension costs should be assessed using actuarial methods, on the basis of reasonable assumptions in line with current best practice.</p>
Principle 5	<p>Under funding/over funding</p> <p>In principle, each price control should make allowance for the ex-ante cost of providing pension benefits accruing during the period of the control, and similarly for any increase or decrease in the cost of providing benefits accrued in earlier periods resulting from changes in the ex-ante assumptions on which these were estimated on a case-by-case basis.</p>
Principle 6	<p>Severance - early retirement deficiency contributions</p> <p>Companies will also be expected to absorb any increase (and may retain the benefit of any decrease) in the cost of providing enhanced pension benefits granted under severance arrangements which have not been fully matched by increased contributions.</p>

2. Are P&OPEB costs included in the costs that are eligible for recovery from customers in each period? If so, what is the rationale for doing so?

Yes, in all jurisdictions, P&OPEB costs are included in the costs that are eligible for recovery from customers i.e. no jurisdiction specifically excludes P&OPEB costs from recoverable costs. In fact, P&OPEB costs are viewed no differently from all other capital and operating costs, albeit that estimation of the cost incurred in each period and the amount to be recovered in rates for each period can be much more complex.

In summary

The key findings identified by the review are:

Regulator	Findings
Ofgem	- Rationale for including P&OPEB costs in revenue requirement for each period is based on an established regulatory principle that all efficient costs of providing a competitive package of pay and benefits (including P&OPEB) are to be recovered in rates.
FERC	- Evaluation of the nature of P&OPEB costs determined that post-retirement benefits are a form of deferred compensation to employees for services provided during their working life. As such, the costs may be properly included in the cost of service during the period that the benefits are earned; and - A general policy based on this evaluation was announced in 1993.
Canadian regulators	- Regulatory approach can vary from case-to case; and - Generally based on decisions made in prior rate applications. Decisions made in rate cases for other regulated entities are also considered.
AER	- P&OPEB costs are considered to be like all other capital and operating costs.
EA	- No specific response was provided because this jurisdiction deals primarily with defined contribution pension plans.

3. How are the P&OPEB costs determined and how do regulators verify that the costs are reasonable?

For most jurisdictions, when the P&OPEB costs relate to defined benefit plans, actuarial valuations are used as reference and inform the process of determining the amount that will ultimately be included in setting rates that are just and reasonable. If the defined benefit plan is accounted for as a defined contribution plan (typically multi-employer or jointly sponsored plans), the extent and rigor of the regulatory review process is of necessity far less. Although actuarial valuation reports that contain aggregated information for all participants in the multi-employer plan are usually available, sufficient information as it relates to an individual participating employer is not available. As such, the regulatory review is generally limited to a review of the cash contribution that is required to be made to the plan during each rate-setting period. If these contributions are not keeping up with the funding required by the plan, there is potential for significant deficits to exist in these plans (which deficits are not recognized by the individual participating employers of the plan).

The key valuation methods, inputs and assumptions used in actuarial valuations are consistent with those detailed in this report.

- If P&OPEB costs are included in rates on a funding basis, the actuarial valuations are submitted to regulators as support for contributions to be made to the benefit plans during the period; or
- If P&OPEB costs are included in rates on an accrual basis, the actuarial valuations prepared on an accrual accounting basis are submitted to regulators as support for the projected expense that is included in revenue requirement. Due to the subjective nature of the actuarial assumptions, FERC and some of the other regulators require the regulated entities to file impact analysis for changes proposed in post-employment benefits prior to them being approved for inclusion in rates.

For Ofgem, the strict pension fund rules that exist in the UK result in the perceived risk of material failure of stewardship over benefit plans being considered to be low. The risk is further mitigated by the fact that all of the defined benefit plans of entities rate-regulated by Ofgem are closed to new entrants. Hence, they will wind-down over time. Nonetheless, from the responses received to the questionnaire, it can be seen that Ofgem spends significant effort in developing an understanding of the drivers and inputs that ultimately determine pension costs that are reported in the actuarial valuation reports.

The procedures that are undertaken by Ofgem include:

- Having government actuaries that are engaged by Ofgem conduct a top-down, high-level review of the actuarial reports that are submitted by regulated entities every three years. The review is principally an information gathering and summarizing exercise that assists Ofgem to assess the reasonableness of the methods and assumptions used to determine pension costs, and to understand the differences between the pension costs of individual regulated entities;
- As most of the actuarial valuations are required to be submitted as of the same date, the regulator's actuaries review the valuation reports and assumptions at the same time. This assists Ofgem in identifying, scrutinizing and further investigating those valuations that are developed from assumptions that appear to be outliers in relation to the group under review;
- Conducting prior period comparisons and evaluating the opportunities being used by regulated entities to minimize pension costs. Ofgem also assesses the risk management practices of the plans. However, the opportunities for direct comparison of benefits offered by the regulated entities are limited due to legislation that protects the benefits of certain employees in the jurisdiction;
- Liaising, as appropriate, with other regulatory agencies that monitor the level of funding and effectiveness of management of the defined benefit pension plans; and
- Using the information from the above reviews, developing a regulator's view of the appropriate benefit funding that is to be included in revenue requirement when the P&OPEB allowance is reset every three years.

For most of the other regulators, however, P&OPEB costs are treated just like any other capital or operating expenditure i.e. the costs are presumed to have been prudently incurred until evidence showing imprudence is presented. At that point, the regulated entity has a burden of proof that the costs were indeed prudently incurred. In addition, the validity of any actuarial assumption can be reviewed and challenged in the context of a rate case, an accounting review, and an audit or investigation.

The review identified that none of the regulators have practices that mandate alignment of P&OPEB with relevant non-utility or private sector entities. Also, none of the regulators had undertaken a comprehensive exercise to compare or benchmark the P&OPEB plan benefits provided by regulated entities.

The responses to the questionnaire would seem to indicate that the reasonableness of P&OPEB costs is receiving elevated focus in the assessment of rate applications submitted to Canadian regulators. In contrast, in Australia and New Zealand, most defined benefit plans have been replaced by defined contribution plans and the legacy defined benefit plans are closed to new entrants. As such, in these jurisdictions the P&OPEB costs are not a significant focus in the setting of rates.

In summary

The key findings identified by the review are:

Regulator	Findings
Ofgem	<ul style="list-style-type: none"> - Ofgem engages the Government Actuary’s Department to conduct a top-down, high-level review of the actuarial reports that are submitted by regulated entities every three years; - Actuaries from the Government Actuary’s Department review the actuarial valuations and assumptions at a synchronized point in time in order to identify, scrutinize and further investigate those valuations that are developed from assumptions that appear as outliers; - Ofgem liaises with other regulatory agencies as appropriate; and - Due to the strict pension fund rules that exist in their jurisdiction, the perceived risk of material failure of stewardship over benefit plans is considered to be low. The risk is further mitigated by the fact that all of the defined benefit plans are closed to new entrants.
FERC	<ul style="list-style-type: none"> - Regulated entities are required to file changes in post-employment benefits prior to them being approved for inclusion in rates; - FERC has no principle that mandates alignment of pension benefits with relevant non-utility or private sectors entities; and

	- In very few cases, the cost is based on a settlement amount negotiated between the regulated entity and its customers thereby limiting direct examination in a proceeding.
Canadian regulators	- Canadian regulators have challenged the level of pension benefits provided by regulated entities to their employees. The reasonableness of post-employment benefits is receiving elevated focus in the assessment of rate applications.
AER and EA	- Most defined benefit plans have been replaced by defined contribution plans and the legacy defined benefit plans are closed to new entrants; as such the P&OPEB costs are not a significant focus in the setting of rates.

4. What method is used for including the P&OPEB costs in the rates charged to customers (i.e. accrual, funding, cash cost or settlement basis) and what is the rationale for the selected method and timing of the cost recovery?

The practice for recovering P&OPEB costs in the rates charged to customers varies significantly from jurisdiction to jurisdiction and, in some jurisdictions, the issue is dealt with on a case-by-case basis. As such, the regulatory practice can vary from utility to utility.

Ofgem applies the specialized methods described in response to question 3 above which are more aligned with the funding basis and their revenue requirement models only permit recovery of these specified amounts. The method parallels the funding basis as all stakeholders are of the view that the funding cost of such long-dated obligations is far more important than amounts based on an accrual basis established for financial reporting purposes. The Ofgem method is a widely accepted practice in its jurisdiction and there have been no significant concerns raised by the regulated entities with this position. As indicated in response to question 3 above, Ofgem makes significant effort to determine its view (as regulator) of the amounts that are to be included in revenue requirement upon rebasing. It should also be noted that, as financial reporting standards in Great Britain (and other jurisdictions that report under IFRS) currently do not permit the recognition of regulatory deferral accounts, any differences between the projected contributions and the contributions actually made are tracked off-balance sheet and only recognized in financial statements if and when the differences are included in revenue requirement.

Further, Ofgem’s regulatory view of the amounts that are included in revenue requirement is comprised of two separate and distinct components:

- Established deficit funding: these are deficit positions from legacy defined benefit plans that were assessed when the pension principles were implemented. The deficits are being tracked and monitored separately and are being funded through revenue requirement over the average expected remaining service period of members of the plan. This period was initially set at 13 years, but is periodically reviewed and has been updated to 15 years; and

- Current pension costs and incremental deficits: amounts for these costs are assessed and included in revenue requirement as part of the overall compensation cost.

On the other hand, FERC, BCUC and UARB generally apply the accrual accounting basis for recovering P&OPEB costs in rates. FERC is of the view that regulatory and financial accounting have a common goal of attempting to allocate accrued costs between periods in a rational manner so that each period bears its equitable portion of costs. FERC concluded that accounting standards provide a reasonable convention for the measurement of the accrued costs and can be applied uniformly by the regulated entities. As such, FERC's stated policy is to apply the accrual basis set out in financial reporting standards. However, FERC requires the following additional conditions to be met in order for a regulated entity to apply the accrual basis of accounting for recovering costs relating to OPEB obligations¹:

- a) The regulated entity must agree to make cash deposits to an irrevocable external trust fund, no less frequently than quarterly, in amounts that are proportional and, on an annual basis equal, to the annual test period allowance for OPEB costs. Additional conditions are specified regarding any cash disbursements made by the trust fund, the independence of the trustee of the fund and soundness of the trust's investment policy; and
- b) The regulated entity must agree, when it is consistent with good business practices to do so, to maximize the use of income tax deductions for contributions to funds of this nature. If tax deductions are not available for some portion of currently funded amounts, deferred income tax accounting must be followed for inclusion of the tax effects of such transactions in costs for determining revenue requirement.

It should, however, be noted that the volatility that would otherwise arise from applying the requirements of accrual accounting standards is significantly reduced by the fact that FERC, BCUC and UARB all require the use of regulatory deferral accounts to record differences between P&OPEB expenses recognized on an accrual basis and the amount that is included in rates. This means that for each period, rate payers only pay for those costs that have been approved by the regulator for inclusion in rates on a forecast basis, rather than an amount derived purely from the application of accounting standards. In fact, none of the regulators reported that their regulatory practice for P&OPEB cost is based solely on the application of the requirements of accounting standards without considering the overall impact on rates.

In certain instances, FERC has also permitted P&OPEB costs to be recovered based on actual employer funding contributions to the post-retirement benefit plans. A recent survey of 52 participating state regulators in the United States noted that commission orders continue to be issued on a mixed case-by-case basis: 60 commission orders were based on accrual principles, 6 were on a cash basis that is similar to the funding contribution method and 12 on various other methods (including a combination of these two methods).

¹ 61 FERC 61,330, Post-Employment Benefits Other Than Pensions, Docket No. PL93-1-000, FERC Statement of Policy (December 17, 1992)

In summary

The key findings identified by the review are:

Regulator	Findings
Ofgem	<ul style="list-style-type: none"> - The amount that is included in revenue requirement is based on the regulator’s view of cash contributions to the defined benefit pension plans; and - Any true-up adjustments to values determined for financial reporting purposes are tracked off-balance sheet and only recognized in financial statements when the differences are included in revenue requirement.
FERC	<ul style="list-style-type: none"> - Generally, accrual basis is used based on the requirements of accounting standards, but adjusted by the use of regulatory deferral accounts; and - Funding contribution cost basis is sometimes used.
Canadian regulators	<ul style="list-style-type: none"> - Generally, accrual basis is used based on the requirements of accounting standards, but adjusted by the use of regulatory deferral accounts or and variance accounts; and - Funding and cash cost basis is sometimes used.
AER	<ul style="list-style-type: none"> - Cash contributions to the defined contribution pension plans are used; and - Forecasts of the contributions are made for a five year period. The projections are only updated every five years as part of the rate reset process (rebased of rates). Normally, true-up adjustments are not made as pass through provisions relate only to exceptional items that fall into particular types of events that exceed a materiality threshold.
EA	<ul style="list-style-type: none"> - Cash contributions to the defined contribution pension plans are used.

5. What oversight role do rate regulators play with regards to P&OPEB plans?

Generally, none of the rate regulators have oversight over P&OPEB plans. For example, in Ofgem’s jurisdiction, pension fund rules limit the influence that the regulated entity and Ofgem can have over the decisions that are made by the trustees of a pension plan. FERC also has no stated principles regarding plan performance and management. That said, regulators have the ability to review and challenge the validity of any actuarial assumption in the context of a rate case or revenue requirement application, through an accounting review, and an audit or investigation. A decision of a rate-setting authority to allow or disallow a component of P&OPEB cost in setting rates can have significant implications for a utility’s P&OPEB plan design.

6. Are any incentives provided to reduce P&OPEB costs?

P&OPEB costs are included and assessed as part of the overall rate application process. Subsequent to this, for jurisdictions with earnings sharing mechanisms and for which specific variances accounts have not been established for P&OPEB costs, the regulatory framework shares over/under earnings for P&OPEB costs between the regulated entity and its customers. Generally, P&OPEB costs would be included together with other items of revenue and expenses. As over/under earnings specifically relating to P&OPEB costs are not separated in the incentive mechanisms, any over/under earnings relating to P&OPEB costs would be ultimately shared between the regulated entity and its customers based on the stipulated over/under earnings sharing ratios.

7. Do P&OPEB plans include employees from non-regulated businesses? If so, how does the regulator verify that the P&OPEB costs that are included in rates relate only to the regulated business?

Yes, some of the P&OPEB plans include employees from non-regulated businesses. As regulatory practice is to avoid any cross-subsidization between regulated and non-regulated businesses, the allocation of costs for the affected plans receives significant focus in a rate application. Regulators approve the cost allocation methodologies. For Ofgem, a pragmatic allocation approach of 80:20 between regulated and non-regulated businesses was initially applied, but utilities are now being allowed to justify different allocation basis depending on their specific facts and circumstances.

Appendix G – Simplified Example of Accounting for a Defined Benefit Plan

This Appendix serves to support the discussion in Appendix C with respect to the various accounting frameworks used by rate-regulated entities.

The following simplified example illustrates the differences between the accounting for a defined benefit plan under IFRS, US GAAP and ASPE based on accounting standards that are in effect for annual reporting periods commencing on or after January 1, 2015. Note that the discussions below exclude the effect of any regulatory deferral account balances that would be recognized:

Example facts and assumptions:

- On 12/31/20x1, funded status of plan is \$5,000, consisting of a defined pension benefit obligation (PBO) of \$10,000 and fair value of plan assets of \$15,000.
- Discount rate and expected return on plan assets at the beginning of the 20x2 year are 7% and 10%, respectively.
- Opening balances in retained earnings or Accumulated Other Comprehensive Income (AOCI) (i.e. depending on the applicable accounting framework) as at 12/31/20x1 are as follows:
 - Unamortized prior service cost = \$2,000;
 - Unamortized actuarial loss = \$2,500; and
 - The expected average remaining service period for both amounts is 10 years.
- Due to a change in plan provisions, prior service costs of \$1,000 arose in 20x2.
- The actuary has determined that current service costs for 20x2 are \$1,100.
- At the end of 20x2, the actuary estimates the PBO to be \$14,500 after taking into account the above prior service costs, and the plan asset custodian reported that the actual fair value of the plan assets is \$17,000.
- Assume cash contributions were \$1,000 for the year and benefit payments were nil.
- For IFRS and US GAAP purposes, it has been determined that the asset ceiling is not applicable.
- For US GAAP reporting, the plan sponsor has elected to recognize the minimum amount using the corridor method.
- There were no changes to the number of employees or other demographic assumptions in 20x2 and 20x3.

Based on the above facts and assumptions, the balances for the defined benefit pension plan will be reported in financial statements that are prepared under IFRS, US GAAP and ASPE as set out below.

IFRS

Under IFRS, the change in the defined benefit plan obligation and plan assets in 20x2 would be as follows:

	PBO \$	Plan Assets \$	Funded Status \$
PBO/plan assets at 12/31/20x1	(10,000)	15,000	5,000
Service cost	(1,100)	-	(1,100)
Interest cost (7% of \$10,000)	(700)	-	(700)
Prior service cost	(1,000)	-	(1,000)
Remeasurement loss (actuarial loss on PBO)	(1,700)	-	(1,700)
Interest earned by plan assets (7% of \$15,000)	-	1,050	1,050
Remeasurement loss (actuarial loss on plan assets)	-	(50)	(50)
Contributions to plan assets	-	1,000	1,000
PBO/plan assets at 12/31/20x2	(14,500)	17,000	2,500

The statement of financial position (balance sheet) would show a long-term net pension asset of \$2,500 on 12/31/20x2. AOCI would have a debit balance of \$4,250, consisting of the opening remeasurement of \$2,500 plus the remeasurements of \$1,750 recognized in the 20x2 year. The amounts relating to past service costs in 20x1 would have been expensed in the previous year.

The net periodic pension costs (“NPPC”) recognized in the income statement for the year-ended 12/31/20x2 are as follows:

Year-ended 12/31/20x2	NPPC \$
Service cost	1,100
Interest cost on PBO	700
Interest earned by plan assets	(1,050)
Immediate recognition of past service costs in income	1,000
Total net periodic pension cost for 20x2 year	1,750

As noted above, past service costs are immediately recognized in income in full. The remeasurement amounts would remain in AOCI (or retained earnings, depending on the entity's accounting policy choice) and would have no impact on net income.

US GAAP

Under US GAAP, the change in the PBO and plan assets in 20x2 would be as follows:

	PBO \$	Plan Assets \$	Funded Status \$
PBO/plan assets at 12/31/20x1	(10,000)	15,000	5,000
Service cost	(1,100)	-	(1,100)
Interest cost (same as IFRS)	(700)	-	(700)
Prior service cost	(1,000)	-	(1,000)
Actuarial loss on PBO	(1,700)	-	(1,700)
Expected return on plan assets (10% of \$15,000)	-	1,500	1,500
Actuarial loss on plan assets	-	(500)	(500)
Contributions to plan assets	-	1,000	1,000
PBO/plan assets at 12/31/20x2	(14,500)	17,000	2,500

The statement of financial position would show a long-term net pension asset of \$2,500 on 12/31/20x2. AOCI would have a debit balance of \$7,400, consisting of the unamortized prior service cost (\$2,000 + \$1,000) and unamortized actuarial losses (\$2,500 + \$2,200) less amortization of past service cost totalling \$200 and amortization of actuarial losses totalling \$100, as shown below.

The NPPC in the income statement for the year-ended 12/31/20x2 are as follows. Note that the same amounts would be recognized under legacy Canadian GAAP:

Year-ended 12/31/20x2	NPPC \$
Service cost	1,100
Interest cost	700
Expected return on plan assets	(1,500)
Amortization of amounts in AOCI:	

- Prior service cost (\$2,000 ÷ 10)	200
- Net actuarial loss (see below)	100
Total net periodic pension cost for 20x2 year	600

Amortization of actuarial loss was \$100 in 20x2, as the net actuarial loss at the beginning of the year (\$2,500) exceeds the greater of 10% of PBO and 10% of plan assets at the beginning of the year. The excess amount of \$1,000 (\$2,500 – (10% x \$15,000)) is amortized over the expected average remaining service period at the beginning of the year (10 years), resulting in the \$100 amortization charge.

Based on the above example, in 20x3, amortization of prior service cost would be \$311, as the amount accumulated in AOCI at the beginning of 20x3 would be \$2,800 (\$1,800 remaining from 12/31/x1 plus \$1,000 arising in 20x2). As there were no changes in the demographic information, the average remaining service period used for amortization would be 9 in 20x3, which would result in \$311 of amortization (\$2,800 ÷ 9).

In 20x3, amortization of net actuarial loss would be \$322, as the amount accumulated in AOCI at the beginning of the year would be \$4,600 (\$2,500 loss from 12/31/x1 plus \$2,200 loss from 20x2 less \$100 amortized in 20x2). The “corridor” would be based on 10% of plan assets of \$17,000, or \$1,700, so the portion of the accumulated actuarial losses above this amount would be amortized over the average remaining service period of 9 years, which results in \$322 ((4,600-\$1,700) ÷ 9).

ASPE

Under ASPE, the change in the PBO and plan assets in 20x2 would be as follows:

	PBO \$	Plan Assets \$	Funded Status \$
PBO/plan assets at 12/31/20x1	(10,000)	15,000	5,000
Service cost	(1,100)	-	(1,100)
Interest cost (7% of \$10,000)	(700)	-	(700)
Prior service cost	(1,000)	-	(1,000)
Actuarial loss on PBO	(1,700)	-	(1,700)
Actual return on plan assets	-	1,000	1,000
Contributions to plan assets	-	1,000	1,000
PBO/plan assets at 12/31/20x2	(14,500)	17,000	2,500

The statement of financial position would show a long-term net pension asset of \$2,500 on 12/31/20x2. The amounts relating to past service costs and actuarial losses in 20x1 would have been fully expensed in the previous year.

The NPPC in the income statement for the year-ended 12/31/20x2 are as follows:

Year-ended 12/31/20x2	NPPC
	\$
Service cost	1,100
Interest cost	700
Actual return on plan assets	(1,000)
Other changes in PBO immediately recognized in net income:	
- Actuarial loss	1,700
- Past service costs	1,000
Total net periodic pension cost for 20x2 year	3,500

In summary:

The results of applying the three different accounting frameworks can be summarized as follows:

Accounting Framework	PBO	Plan Assets	Funded Status	AOCI	NPPC
	\$	\$	\$	\$	\$
IFRS	(14,500)	17,000	2,500	4,250	1,750
US GAAP	(14,500)	17,000	2,500	7,400	600
ASPE	(14,500)	17,000	2,500	-	3,500

Appendix H – Recent Publicity Regarding the Funded Status of Pension Plans

The funded status of most DB pension plans in Canada declined significantly during the financial crisis of 2008 – 2009. However, by early 2014 the funded status had improved significantly.

However, since early 2014, there has been a steady decrease in the funded status of most DB pension plans in Canada. There are three main reasons for this:

- a) Significant volatility in the global equity markets: pension plans in Ontario are invested 52 per cent in equities on average, based on statistics from FSCO¹. The ongoing volatility in equity markets (exhibiting periods of very strong growth followed by sharp declines) has a significant impact on a pension plan’s assets and funded status;
- b) Continuing declines in long-term bond yields: the decline in long-term interest rates results in an increase in the present value of pension plan liabilities as well as reduced earnings on the pension plan assets. Long-term interest rates impact the valuation of pension plan liabilities (i.e. accounting and solvency valuations);
- c) Weakening of the Canadian dollar during 2015: the Canadian dollar weakened significantly during 2015 and this positively impacted the return on unhedged foreign assets. The Canadian dollar has strengthened somewhat during the first quarter of 2016.

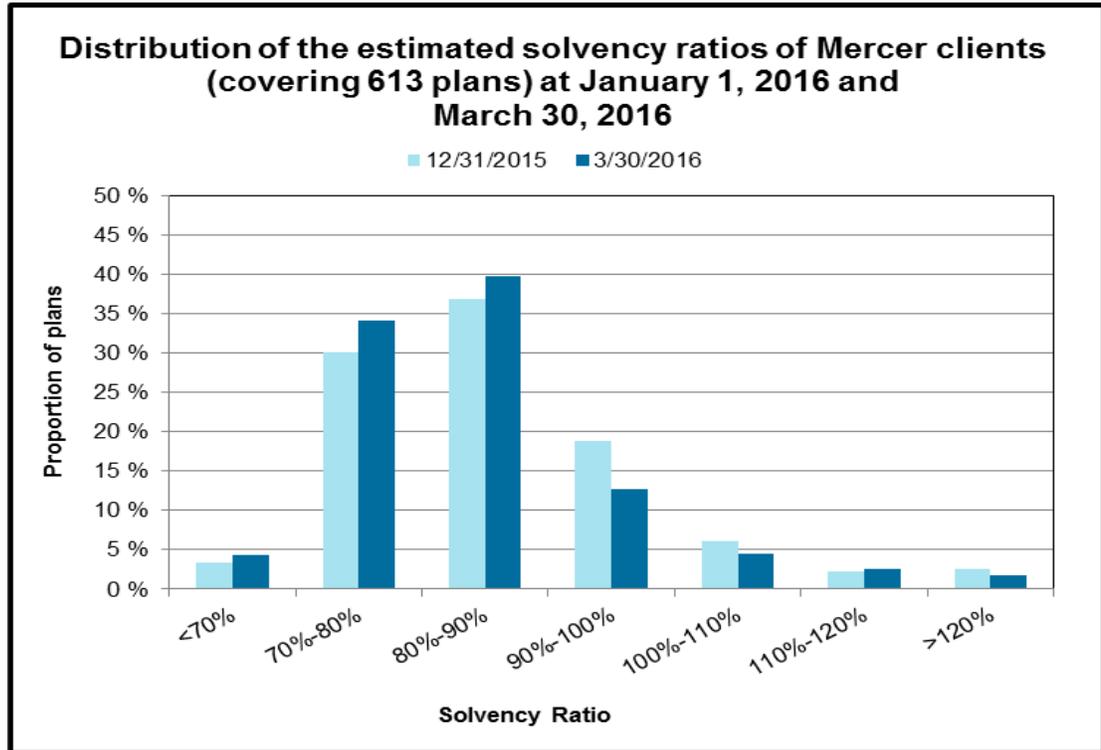
It is important to note that these factors can have an offsetting impact that can mask the significant volatility that can arise during a given period of time.

Actuarial consulting firm Mercer’s Pension Health Index, which tracks the funded status of a hypothetical defined benefit pension plan, stood at 82% at December 31, 2012 and had increased to 106% at December 31, 2013. The index was 95% at December 31, 2014 and decreased to 93% at December 31, 2015. At March 31, 2016 the index was at 90%. Mercer noted that while there is wide variance in the funded status of Canadian pension plans, the median solvency ratio of the pension plans of Mercer clients decreased 3% to 82% during the first quarter of 2016 with more than 9 out of 10 plans being in solvency deficit position.²

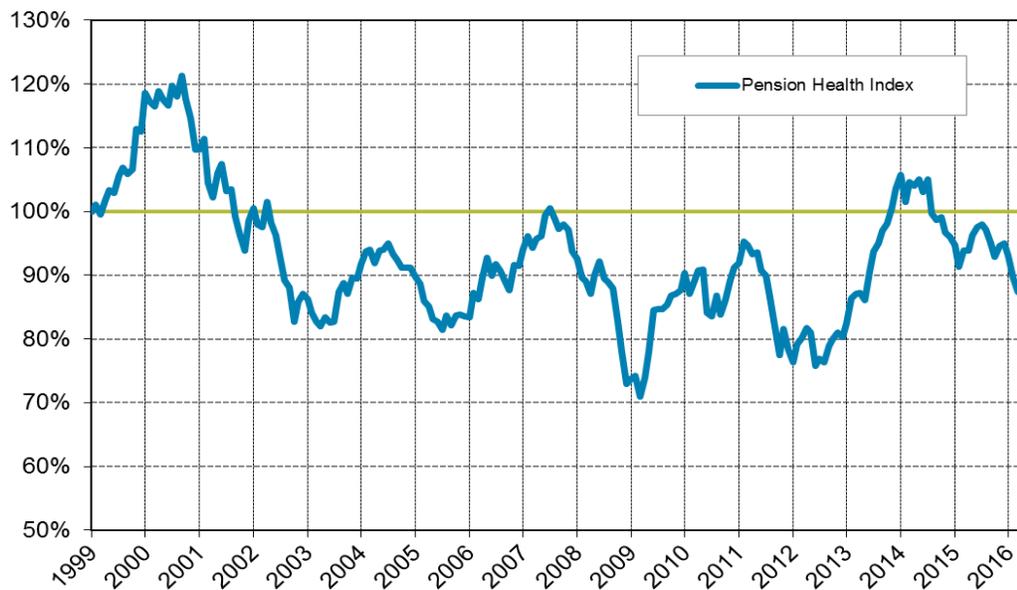
The chart below compares the distribution of the estimated solvency ratios of Mercer clients (covering 613 plans) at January 1, 2016 and March 30, 2016:

¹ FSCO’s 2014 Report on the Funding of Defined Benefit Pension Plans in Ontario; March 2015, Financial Services Commission of Ontario,
<https://www.fSCO.gov.on.ca/en/pensions/actuarial/Documents/2014DBFundingReportv2.pdf>

² Mercer Pension Health Index – based on report for the first quarter of 2016 dated March 31, 2016



Mercer Pension Health Index



Appendix I - Illustrative Examples of US GAAP Accounting Practices by Canadian Regulated Entities

The following are illustrative examples of the accounting practices that are followed by some of the Canadian regulated entities that prepare their general purpose financial statements based on US GAAP.

As more fully discussed in Section 2.4 of this report, it can be noted that, generally, most of the regulated entities have been able to meet the criteria in ASC 980 to record regulatory assets and liabilities relating to pension obligations. For example, in the illustrative examples below, although FortisAlberta recovers the cost of defined benefit pension plans in customer rates based on the cash payments made, FortisAlberta recognizes regulatory assets and liabilities for any difference between this method and accrual accounting.

For OPEB, however, regulatory assets and liabilities have only been recognized on those plans that are not recovering OPEB costs on a ‘pay-as-you-go’ basis – see further details in Section 3.5 of this report. For example, in the illustrative examples below, as FortisAlberta recovers the cost of OPEB plans in customer rates based on the cash payments made, FortisAlberta does not recognize regulatory assets for any difference between this method and accrual accounting.

1.1 Accounting Practices for Pension – Regulatory Assets Recognized

a) Extracts from Hydro One Inc.’s consolidated financial statements for the year ended December 31, 2014 (audited by KPMG)

Note 2 – Significant Accounting Policies

In accordance with the OEB’s rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the Pension Benefits Act (Ontario). Pension costs are recorded on an accrual basis for financial reporting purposes.

Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan. The regulatory asset for the net underfunded projected benefit obligation for the pension plan, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension regulatory assets are remeasured at the end of each year based on the current status of the pension plan.

b) Extracts from Fortis Inc.'s consolidated financial statements for the year ended December 31, 2014 (audited by Ernst & Young)

Note 3 – Summary of Significant Accounting Policies

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made.

Any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 7 (ii)).

Note 7(ii) – Regulatory Assets and Liabilities

Employee Future Benefits

The regulatory asset and liability associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and transitional obligations associated with defined benefit pension [and OPEB plans] maintained by the Corporation's regulated utilities, which are expected to be recovered from, or refunded to, customers in future rates (Note 28).

At the Corporation's regulated utilities, as approved by the respective regulators, differences between defined benefit pension [and OPEB plan] costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset or liability. These amounts would otherwise be recognized in accumulated other comprehensive loss on the consolidated balance sheet.

As at December 31, 2014, regulatory assets of approximately \$339 million associated with employee future benefits were not subject to a regulatory return (December 31, 2013 – \$130 million). As at December 31, 2014, regulatory liabilities of approximately \$55 million associated with employee future benefits were not subject to a regulatory return (December 31, 2013 – \$55 million).

1.2 Accounting Practices for OPEB – Regulatory Assets Recognized

- a) Extracts from Hydro One Inc.'s consolidated financial statements for the year ended December 31, 2014 (audited by KPMG)

Note 2 – Significant Accounting Policies

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis.

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

- b) Extracts from Fortis Inc.'s consolidated financial statements for the year ended December 31, 2014 (audited by Ernst & Young)

Note 3 – Summary of Significant Accounting Policies

With the exception of FortisAlberta, as discussed below, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 7 (ii)).

- i) Additional information contained in FortisBC Inc.'s separate financial statements for the year ended December 31, 2014 (audited by Ernst & Young):

Note 8 – Regulatory Assets and Liabilities

The net funded status, being the difference between the fair value of plan assets and the projected benefit obligation for pensions and OPEBs, is required to be recognized on the Corporation's balance sheet under ASC Topic 715. The amount required to make this net funded status adjustment, which would otherwise be recognized in Accumulated Other Comprehensive Income ("AOCI"), has instead been deferred as a regulatory asset. The regulatory asset represents the deferred portion of the expense relating to pensions and OPEBs that is expected to be recovered from customers in future rates as the deferred amounts are included as a component of future net benefit cost. The regulatory asset balance is not subject to a regulatory return.

Up until the end of 2011, a cumulative difference existed between the pension and OPEB amounts to be recognized under ASC Topic 715 and the pension and OPEB amounts recovered in rates as approved by the BCUC. This cumulative transitional amount, which was measured as of January 1, 2000, would otherwise be recognized in retained earnings but instead has been approved by the BCUC for deferral as a regulatory asset and to be collected from customers over a term of twelve years beginning on January 1, 2012. This regulatory asset balance is not subject to a regulatory return.

Also included in this balance is the variance between 2012 and 2013 actual pension and OPEB expense and the amounts forecast for rate-setting purposes which has been deferred as a regulatory asset as approved by the BCUC. The regulatory asset balance is expected to be recovered from customers in future but it is not subject to a regulatory return.

- ii) Additional information contained in Newfoundland Power Inc.'s separate financial statements financial statements for the year ended December 31, 2014 (audited by Ernst & Young):

Note 2 – summary of Significant Accounting Policies

Effective January 1, 2011, the PUB ordered the creation of an OPEBs cost variance deferral account. This account is charged or credited with the amount by which actual OPEBs expense differs from amounts approved in customer rates by the PUB due to variations in assumptions. Each year, at March 31, the balance in the OPEBs cost variance deferral account will be transferred to the Company's RSA and disposed of in accordance with the operation of the RSA. See Note 6(i).

Note 6(i) – Regulatory Assets and Liabilities

As described in Note 2, the PEVDA and OPEBs cost variance deferral accounts capture the difference due to variations in assumptions between the annual pension and OPEBs expense approved for rate setting purposes and the actual pension and OPEBs expense. The balances in these accounts are transferred to the RSA on March 31 in the year in which the differences arise. The amount transferred from the PEVDA and OPEBs cost variance deferral account to the RSA for recovery from customers in 2014 was \$1.2 million and \$0.6 million, respectively (2013 - \$2.1 million and \$0.5 million, respectively).

Note 6(ii) – Regulatory Assets and Liabilities

This regulatory asset represents the accumulated difference between OPEBs expense recognized on a cash basis for regulatory purposes and an accrual basis for financial reporting purposes since 2000 until December 31, 2010. Effective January 1, 2011, the PUB

ordered the adoption of the accrual method of accounting for OPEBs and the \$52.6 million regulatory asset be amortized equally over 15 years.

1.3 Accounting Practices for OPEB – No Regulatory Assets Recognized

a) Extracts from Fortis Inc.’s consolidated financial statements for the year ended December 31, 2014 (audited by Ernst & Young)

Note 3 – Summary of Significant Accounting Policies

As approved by the regulator, the cost of OPEB plans at FortisAlberta is recovered in customer rates based on the cash payments made.

At FortisAlberta, the difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates does not meet the criteria for deferral account treatment and, therefore, FortisAlberta recognizes in earnings the cost associated with its OPEB plan as actuarially determined, rather than as approved by the regulator. Unamortized OPEB plan balances at FortisAlberta related to net actuarial gains and losses and past service costs are recognized as a component of other comprehensive income.

i) Additional information contained in FortisAlberta Inc.’s separate financial statements financial statements for the year ended December 31, 2014 (audited by Ernst & Young):

Note 2 – Summary of Significant Accounting Policies

In the case of the OPEB plan, unrecognized actuarial gains and losses and past services costs and credits are not subject to deferral treatment and are recognized as a component of other comprehensive income (“OCI”).

The Corporation recovers in customer rates employee future benefit costs based on estimated cash payments. Any difference between the expense recognized under US GAAP for defined benefit pension plans and that recovered in current rates, which is expected to be recovered or refunded in future rates, is subject to deferral treatment. Any difference between the expense recognized under US GAAP for the OPEB plan and that recovered in current rates, which is expected to be recovered or refunded in future rates, is not subject to deferral treatment.

Appendix J - Examples of Additional Guidance issued under US GAAP by Other Regulators

1.1 Additional Guidance Issued by FERC

a) Extracts from FERC Docket No. AI04-2-000 dated March 29, 2004

Question: At the time the entity recognizes its minimum pension liability in accordance with SFAS No. 87, *Employers' Accounting for Pension* (which is a legacy accounting standard prior to the recent codification as part of ASC 715-30), should it recognize a regulatory asset for the amount of the liability otherwise chargeable to accumulated other comprehensive income that relates to its cost based rate-regulated business segment?

Response: The cost of pension benefits provided to employees under a defined pension benefit plan are recognized as an expense at the time the employee provides related employment services. SFAS No. 87 contains a delayed recognition feature. This means that changes in the pension obligation and the value of assets set aside to meet these obligations are not recognized when they occur but are recognized systematically and gradually over subsequent periods. An entity that determines its pension allowance included in its costs based regulated rates on the basis of SFAS No. 87 adopts that same delayed recognition feature for ratemaking purposes. That is, changes in the pension obligation and assets set aside to meet those obligations are not included in rates when they occur but rather are included in rates systematically and gradually in subsequent periods. The recognition of a minimum pension liability which would otherwise be charged to accumulate[d] other comprehensive income therefore constitutes a measurement of the changes in pension obligations and the value of plan assets that are to be included in the determination of rates in subsequent periods in so far as they relate to the cost based rate regulated segment of the entity.

Under the Commission's accounting requirements regulatory assets are to be established for those charges that would have been included in net income or accumulated other comprehensive income determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services.

Therefore, in the circumstances described above and provided that it is probable that the pension allowance to be included in rates in future periods will continue to be calculated on the basis of SFAS No. 87, **entities shall recognize a regulatory asset for the minimum pension liability otherwise chargeable to accumulated other comprehensive income related to its cost based rate regulated business segments.**

Further, the minimum pension liability, as well as, any related regulatory asset is not amortized over future periods. At each measurement date, the entry recorded for the previous measurement date is reversed and the computation redone. A new minimum liability and related regulatory asset would be recognized, if required, at the new measurement date.

This guidance is for accounting purposes only and does not limit the Commission from reviewing the reasonableness of the elements of pension expense included in future rate proceedings before the Commission.

b) Extracts from FERC Docket No. AI07-1-000 dated March 29, 2007

Under the Commission's accounting requirements, regulatory assets or liabilities are to be established for amounts that would have been included in net income or accumulated other comprehensive income determinations in the current period under the general requirements of the Uniform Systems of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services.

Therefore, in the circumstances described above and provided that it is probable that the postretirement benefit allowance to be included in rates in future periods will continue to be calculated on the basis of SFAS No. 87 and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (which is a legacy accounting standard prior to the recent codification as part of ASC 715-60), entities shall recognize a regulatory liability or asset for the funded status asset or liability otherwise chargeable to accumulated other comprehensive income under SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* (which is a legacy accounting standard prior to the recent codification as part of ASC 715-30 and ASC 715-60), related to its cost-based, rate-regulated business segments.

Further, the funded status asset or liability that must be recognized under SFAS No. 158, as well as any related regulatory liability or asset is not amortized over future periods. At each measurement date, the entry recorded for the previous measurement date is reversed and the computation redone. A new funded status asset or liability and related regulatory liability or asset would be recognized, if required, at the new measurement date.

This guidance is for accounting purposes only and does not limit the Commission from reviewing the reasonableness of the elements of postretirement benefit expense included in future rate proceedings before the Commission.

c) Extracts from FERC Docket No. PL93-1-000 dated December 17, 1992

The policy

It shall be the policy of the Commission to recognize, as a component of jurisdictional cost-based rates of natural gas pipeline companies and public utilities under its jurisdiction, and oil pipelines should they elect to comply with this statement, allowances for prudently incurred costs of PBOPs (i.e. OPEB) of company employees when determined on an accrual basis (and supported by independent actuarial studies) that are consistent with the accounting principles set forth in SFAS 106 provided that the following conditions are met:

- (1) The company must agree to make cash deposits to an irrevocable external trust fund, for no less frequently than quarterly, in amounts that are proportional and, on an annual basis equal, to the annual test period allowance for PBOPs. The trust must provide that any disbursements made from the trust are limited to payments for the benefit of employees pursuant to the company's postretirement plans, payments for expenses of the trust, and refunds to customers pursuant to a Commission approved refund plan in the event the funds are not to be paid to employees. The trustee must be independent of the company and authorized to make only those investments which are consistent with sound investment policies for funds of this nature.
- (2) The company must agree, when it is consistent with good business practices to do so, to maximize the use of income tax deductions for contributions to funds of this nature. If tax deductions are not available for some portion of currently funded amounts, deferred income tax accounting must be followed for the tax effects of such transactions.

The jurisdictional company must file within three years of its adoption of SFAS 106 accounting a general rate change under section 4 of the Natural Gas Act or section 205 of the Federal Power Act (or in the case of oil pipeline companies which elect to do so, section 6 of the Interstate Commerce Act), as appropriate, and seek inclusion of these costs in its rate levels, in order to obtain rate recovery of PBOPs on an accrual basis. The company may defer the jurisdictional portion of the difference between PBOPs determined pursuant to accounting principles previously followed and SFAS 106 accruals from the time it adopts SFAS 106 until the company files such general rate case which includes costs related to SFAS 106 and places such rates into effect. The regulatory asset (or liability) thus created and attributable to its jurisdictional cost-based rates is to be amortized over a period to be determined in the rate proceeding, but in no event to exceed twenty years beyond the SFAS 106 adoption date. Amortization of the regulatory asset (or liability) will be eligible for recovery in future rates.

The purpose of this policy statement is to provide guidance for the efficient disposition of pending or future cases which include PBOPs as a component of the cost of service and to provide a statement of the Commission's intent to permit recovery in future rates of PBOP costs appropriately deferred. The Commission is mindful that a general policy statement is an articulation of the Commission's intention, which will be followed unless particular

circumstances demonstrate the policy to be inappropriate. Where, as here, the Commission has adopted a general statement of Commission policy, both the underlying validity of the policy and its application to particular facts may be challenged and are subject to further consideration in individual cases.

Funding Requirements

The Commission will require that an irrevocable trust be established to insure that the amounts that the customers are paying for PBOPs will, in fact, be utilized for such purpose, or in the event that they are not, that customers obtain refunds of the funds accrued in the trust account, including any earnings thereon, for the excess amounts paid. The Commission believes that such protection is necessary for several reasons.

There may be long periods between the time that rates reflect the cost of PBOPs and the time that payments are made to employees. During such periods many events could occur that would affect the ultimate payments or the amounts required to make such payments. For instance, there could be major changes in a company's post-retirement plans due to the advent of new governmental programs or for other reasons. Also, there could be significant changes from what was anticipated in the factors that affect annual accruals, such as inflation rates and investment earnings, thereby enabling settlement of post-retirement obligations through alternative means and to realize a gain on plan assets after settlement.

FASB statements permit in certain instances gains realized on settlements and curtailments of post-retirement plans to be taken to income. Recognition of income by the regulated company without a concurrent reduction in rates would not be fair to customers, particularly if any shortfalls in fund assets are to be made up through increased future rates. That would be the effect of adopting the accounting principles of SFAS 106 for ratemaking purposes. A mandatory requirement to establish an irrevocable trust will prevent the company from realizing income not intended to be earned when the rates were originally established by the Commission. The Commission recognizes that the earning rate for external funding may be lower than the effective earning rate that could be realized from internal funds. However, the Commission believes that fund security is more important than earning rates in this instance and will therefore require external funding.

Appendix K – Specific Accounting Requirements under US GAAP

1.1 General Accounting Requirements

980-10 - Overall

980-10-05-3 Regulation of an entity's rates (also referred to as prices) is sometimes based on the entity's costs. Regulators use a variety of mechanisms to estimate a regulated entity's allowable costs, and they allow the entity to charge rates that are intended to produce revenue approximately equal to those allowable costs. Specific costs that are allowable for rate-making purposes result in revenue approximately equal to the costs.

980-10-05-8 Unless an accounting order indicates the way a cost will be handled for rate-making purposes, it causes no economic effects that would justify deviation from the GAAP applicable to business entities in general. The mere issuance of an accounting order not tied to rate treatment does not change an entity's economic resources or obligations. In other words, the economic effect of regulatory decisions—not the mere existence of regulation—is the pervasive factor that determines the application of GAAP.

980-10-15-2 The guidance in the Regulated Operations Topic applies to general-purpose external financial statements of an entity that has regulated operations that meet all of the following criteria:

- a) The entity's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.
- b) The regulated rates are designed to recover the specific entity's costs of providing the regulated services or products. This criterion is intended to be applied to the substance of the regulation, rather than its form. If an entity's regulated rates are based on the costs of a group of entities and the entity is so large in relation to the group of entities that its costs are, in essence, the group's costs, the regulation would meet this criterion for that entity.
- c) In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the entity's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs.

980-10-15-5 Guidance in other Codification Topics that applies to entities in general also applies to regulated entities. However, entities subject to this Topic shall apply it instead of any conflicting provisions of other parts of the Codification.

1.2 Requirements for Regulatory Assets

980-340 – Other Assets and Deferred Costs

980-340-25-1 Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

- c) It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.
- d) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

980-340-40-1 If at any time an entity's incurred cost no longer meets the criteria for the capitalization of an incurred cost (see paragraph 980-340-25-1), that cost shall be charged to earnings.

980-350-50-1 In some cases, a regulator may permit an entity to include a cost that would be charged to expense by an unregulated entity as an allowable cost over a period of time by amortizing that cost for rate-making purposes, but the regulator does not include the unrecovered amount in the rate base. That procedure does not provide a return on investment during the recovery period. If recovery of such major costs is provided without a return on investment during the recovery period, the entity shall disclose the remaining amounts of such assets and the remaining recovery period applicable to them.

980-340-55-2 In some cases, a regulator may approve rates that are intended to recover an incurred cost over an extended period without a return on the unrecovered cost during the recovery period.

980-340-55-3 The regulator's action provides reasonable assurance of the existence of an asset (see paragraph 980-340-25-1). Accordingly, the regulated entity would capitalize the cost and amortize it over the period during which it will be allowed for rate-

making purposes. That cost would not be recorded at discounted present value. An exception to this general rule is provided for costs of abandoned plants.

1.3 Requirements for Regulatory Liabilities

980-405 – Liabilities

980-405-25-1 Rate actions of a regulator can impose a liability on a regulated entity. Such liabilities are usually obligations to the entity's customers. The following are the usual ways in which liabilities can be imposed and the resulting accounting:

- a) A regulator may require refunds to customers. Refunds can be paid to the customers who paid the amounts being refunded; however, they are usually provided to current customers by reducing current charges. Refunds that meet the criteria of accrual of loss contingencies (see paragraph 450-20-25-2) shall be recorded as liabilities and as reductions of revenue or as expenses of the regulated entity.
- b) A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the entity to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the entity shall not recognize as revenues amounts charged pursuant to such rates. The usual mechanism used by regulators for this purpose is to require the regulated entity to record the anticipated cost as a liability in its regulatory accounting records. Those amounts shall be recognized as liabilities and taken to income only when the associated costs are incurred.
- c) A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. That would be accomplished, for rate-making purposes, by amortizing the gain or other reduction of net allowable costs over those future periods and reducing rates to reduce revenues in approximately the amount of the amortization. If a gain or other reduction of net allowable costs is to be amortized over future periods for rate-making purposes, the regulated entity shall not recognize that gain or other reduction of net allowable costs in income of the current period. Instead, it shall record it as a liability for future reductions of charges to customers that are expected to result.

980-405-40-1 Actions of a regulator can eliminate a liability only if the liability was imposed by actions of the regulator.

1.4 Requirements for P&OPEB

980-715 – Compensation - Retirement Benefits

- 980-715-05-2 This Subtopic provides guidance for the difference between net periodic pension cost as defined in Subtopic 715-30 and amounts of pension cost considered for rate-making purposes as an asset or a liability created by the actions of the regulator.
- 980-715-05-3 This Subtopic provides guidance for the difference between net periodic postretirement benefit cost as defined in Subtopic 715-60 and amounts of postretirement benefit cost considered for rate-making purposes as an asset or a liability created by the actions of the regulator.
- 980-715-25-1 This Subtopic requires that the difference between net periodic pension cost as defined in Subtopic 715-30 and amounts of pension cost considered for rate-making purposes be recognized as an asset or a liability created by the actions of the regulator. Those actions of the regulator change the timing of recognition of net pension cost as an expense; they do not otherwise affect the requirements of that Subtopic.
- 980-715-25-3 For purposes of this Subtopic, other postretirement benefits refer to all forms of benefits, other than pensions, provided by an employer to retirees.
- 980-715-25-4 For continuing postretirement benefit plans, a regulatory asset related to Subtopic 715-60 costs shall not be recorded if the regulator continues to include other postretirement benefit costs in rates on a pay-as-you-go basis. The application of this Topic requires that a rate-regulated entity's rates be designed to recover the specific entity's costs of providing the regulated service or product. Accordingly, an entity's cost of providing a regulated service or product includes the costs provided for in Subtopic 715-60.
- 980-715-25-5 For a continuing postretirement benefit plan a rate-regulated entity shall recognize a regulatory asset for the difference between Subtopic 715-60 costs and other postretirement benefit costs included in the entity's rates if the entity does both of the following:
- a) Determines that it is probable that future revenue in an amount at least equal to the deferred cost (regulatory asset) will be recovered in rates.
 - b) Meets all of the following criteria:
 1. The rate-regulated entity's regulator has issued a rate order or issued a policy statement or a generic order applicable to entities within the regulator's jurisdiction that allows both for the deferral of Subtopic 715-60 costs and for the subsequent inclusion of those deferred costs in the entity's rates.

2. The annual Subtopic 715-60 costs (including amortization of the transition obligation) will be included in rates within approximately five years from the date of adoption of that Subtopic. The change to full accrual accounting may take place in steps, but the period for deferring additional amounts shall not exceed approximately five years.
3. The combined deferral-recovery period authorized by the regulator for the regulatory asset shall not exceed approximately 20 years from the date of adoption of Subtopic 715-60. To the extent that the regulator imposes a deferral-recovery period for those costs provided for in Subtopic 715-60 greater than approximately 20 years, any proportionate amount of such costs not recoverable within approximately 20 years shall not be recognized as a regulatory asset.
4. The percentage increase in rates scheduled under the regulatory recovery plan for each future year shall be no greater than the percentage increase in rates scheduled under the plan for each immediately preceding year. This criterion is similar to that required for phase-in plans in paragraph 980-340-25-3(d). Recovery of the regulatory asset in rates on a straight-line basis would meet this criterion.

980-715-25-8 If an entity does not initially meet the criteria established in Section 980-715-25 but meets those criteria in a subsequent period, then a regulatory asset related to Subtopic 715-60 costs shall be recognized in the period those criteria are met.

980-715-50-1 A rate-regulated entity shall disclose in its financial statements a description of the regulatory treatment of postretirement benefit costs, the status of any pending regulatory action, the amount of any Subtopic 715-60 costs deferred as a regulatory asset at the balance sheet date, and the period over which the deferred amounts are expected to be recovered in rates.

980-715-55-2 An employer with regulated operations shall account for the effects of applying Subtopic 715-30 for financial reporting purposes even if another method of accounting for pensions is used for determining allowable pension cost for rate-making purposes.

980-715-55-4 If this Subtopic applies to the employer, and the amount of net periodic pension cost determined under the method used for rate-making purposes differs from that determined under Subtopic 715-30, the difference would be either of the following:

- a) An asset if the criteria in paragraph 980-340-25-1 are met
- b) A liability if the situation is as described in paragraph 980-405-25-1(b).

980-715-55-5 Usually, continued use of different methods for rate-making purposes and general-purpose external financial reporting purposes would result in either the criteria in paragraph 980-340-25-1 being met or the situation described in paragraph 980-405-25-1(b). However, if pension cost determined in accordance with Subtopic 715-30

exceeds pension cost determined in accordance with the method used in setting current rates, the criteria in paragraph 980-340-25-1 would not be met if both of the following conditions exist:

- a) It is probable that the regulator soon will accept a change for rate-making purposes so that pension cost is determined in accordance with Subtopic 715-30.
- b) It is not probable that the regulator will provide revenue to recover the excess cost that results from the use of Subtopic 715-30 for financial reporting purposes during the period between the date that the employer adopts that Subtopic and the rate case implementing the change.

980-715-55-6 Similarly, if pension cost determined in accordance with the method used in setting current rates exceeds pension cost determined in accordance with Subtopic 715-30, the situation would not be as described in paragraph 980-405-25-1(b) if it is probable that all of the following conditions exist:

- a) The regulator soon will accept a change for rate-making purposes so that pension cost is determined in accordance with Subtopic 715-30.
- b) The regulator will not hold the employer responsible for the costs that were intended to be recovered by the current rates and that have been deferred by the change in method.
- c) The regulator will provide revenue to recover those same costs when they are eventually recognized under the method required by Subtopic 715-30.

980-715-55-7 Because a regulator cannot eliminate a liability that was not imposed by its actions, the need to recognize the underfunded status of a defined benefit plan as a liability under paragraphs 715-30-25-1 through 25-2 is unaffected by regulation.

1.5 Definition of terms used under US GAAP

Terms used in ASC 980 have the following definitions:

Allowable Costs

All costs for which revenue is intended to provide recovery. Those costs can be actual or estimated. In that context, allowable costs include interest cost and amounts provided for earnings on shareholders' investments.

Capitalize

Capitalize is used to indicate that the cost would be recorded as the cost of an asset. That procedure is often referred to as deferring a cost, and the resulting asset is sometimes described as a deferred cost.

Incurred Cost

A cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and has been or must be paid for.

Defined Benefit Plan

A defined benefit plan provides participants with a determinable benefit based on a formula provided for in the plan.

- a) Defined benefit health and welfare plans—Defined benefit health and welfare plans specify a determinable benefit, which may be in the form of a reimbursement to the covered plan participant or a direct payment to providers or third-party insurers for the cost of specified services. Such plans may also include benefits that are payable as a lump sum, such as death benefits. The level of benefits may be defined or limited based on factors such as age, years of service, and salary. Contributions may be determined by the plan's actuary or be based on premiums, actual claims paid, hours worked, or other factors determined by the plan sponsor. Even when a plan is funded pursuant to agreements that specify a fixed rate of employer contributions (for example, a collectively bargained multiemployer plan), such a plan may nevertheless be a defined benefit health and welfare plan if its substance is to provide a defined benefit.
- b) Defined benefit pension plan—A pension plan that defines an amount of pension benefit to be provided, usually as a function of one or more factors such as age, years of service, or compensation. Any pension plan that is not a defined contribution pension plan is, for purposes of Subtopic 715-30, a defined benefit pension plan.
- c) Defined benefit postretirement plan—A plan that defines postretirement benefits in terms of monetary amounts (for example, \$100,000 of life insurance) or benefit coverage to be provided (for example, up to \$200 per day for hospitalization, or 80 percent of the cost of specified surgical procedures). Any postretirement benefit plan that is not a defined contribution postretirement plan is, for purposes of Subtopic 715-60, a defined benefit postretirement plan. (Specified monetary amounts and benefit coverage are collectively referred to as benefits.)

'Pay-as-you-go' basis

A method of financing a pension plan [or OPEB plan] under which the contributions to the plan are generally made at about the same time and in about the same amount as benefit payments and expenses becoming due.

Probable

The future event or events are likely to occur.

Appendix L – Acronyms Used In This Report

AOCI	Accumulated Other Comprehensive Income
ASC	Accounting Standards Codification (other than references identified as relating to regulatory accounting treatment under ASC 980, all other references to ASC relate to general accrual accounting principles applicable under US GAAP)
ASPE	Accounting Standards for Private Enterprise
CAPSA	Canadian Association of Pension Supervisory Authorities
CICA	Canadian Institute of Chartered Accountants, now CPA Canada
CPA Canada	Chartered Professional Accountants Canada, formerly CICA
CRA	Canada Revenue Agency (taxing authority in Canada)
DB	Defined Benefit
DC	Defined Contribution
FERC	Federal Energy Regulatory Commission (US utility rate-regulator)
FSCO	Financial Services Commission of Ontario (supervisory authority under PBA)
GAAP	Generally Accepted Accounting Principles
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
MRC	Minimum Required Contribution (pursuant to PBA)
OCI	Other Comprehensive Income (pursuant to GAAP, a category of equity on a statement of financial position)
OEB	Ontario Energy Board
Ofgem	Office of Gas and Electricity Markets (UK utility regulator)
OMERS	Ontario Municipal Employees Retirement System
OPG	Ontario Power Generation
OPEB	Other Post-Employment Benefits (e.g., health, dental, vision benefits) – excludes pension benefits
P&OPEB	Pension and Other Post-Employment Benefits
PBA	Pension Benefits Act, Ontario and rules and regulations
PBGF	Pension Benefits Guarantee Fund (pursuant to PBA)



PILs	Payments in Lieu of Taxes
SERP	Supplemental Employee Retirement Pension Plan
US GAAP	United States generally accepted accounting principles
