ONTARIO ENERGY BOARD

BOARD STAFF SUBMISSION

Enbridge Gas Distribution Inc.

2014-2018 Customized IR Application

Board File No. EB-2012-0459

April 15, 2014

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Introduction

Enbridge Gas Distribution Inc. ("Enbridge" or "Company") filed an application on July 3, 2013 with the Ontario Energy Board (the "Board") under section 36 of the Ontario Energy Board Act, S.O. 1998, c.15, Schedule B for an order or orders approving rates for a five year period commencing January 1, 2014.

Enbridge's application seeks approval of what it calls a "Customized Incentive Regulation" approach to ratemaking.[1] Enbridge has included evidence on the proposal under which annual revenues would be established for each of the years 2014 to 2018 underpinned by forecasts of O&M expenses, capital expenditures, depreciation, gas supply costs, and taxes. The revenue requirements associated with the application are (in Billions) $2.5, $2.7, $2.8, $2.9 and $2.9 in each of the years 2014 to 2018 respectively for a total of $13.5 Billion.

The nature of the proposal was challenged by several parties at the outset, led by the School Energy Coalition ("SEC"). SEC submitted that Enbridge's proposed ratemaking approach ran contrary to the Board's usual Incentive Regulation Mechanism ("IRM") approach which is to de-couple revenues and costs. SEC requested that the Board hear a preliminary matter before launching in full into the proceeding. SEC raised a concern that if the Board were to wait until the end of the proceeding, and were to decide against Enbridge's approach, time and money would be wasted. SEC argued that it would be more efficient to make a determination up front as to the appropriate ratemaking framework.

The Board considered written arguments on whether it should hear a preliminary issue and in its decision dated October 3, 2014 found that the most efficient course was to proceed immediately to hear the entire application.

The Board also found that it was not obligated to either approve or deny the framework as proposed by Enbridge. The Board said that it would not be restricted from establishing an alternative ratemaking framework, were it to find that it would be appropriate to do so, and provided that there was an evidentiary basis for it.

The Board thereafter set out its process for the consideration of Enbridge's application which included an Information Session, an Issues Day, written interrogatories, a Technical Conference, written undertakings from the Technical Conference, and a

[1] Also called the "Customized IR Plan".

Settlement Conference. There was no settlement on any of the issues at the Settlement Conference.

Board staff sponsored an expert witness, Dr. Lawrence Kaufmann of Pacific Economics Group, to produce an independent assessment of Enbridge's ratemaking proposal. His report was filed on October 23, 2013.

On November 5, 2013 the Board accepted a full Settlement Agreement concerning the 2014 Gas Supply plan and a related new deferral account, the 2014 Unabsorbed Demand Charges Deferral Account which will record TCPL unabsorbed demand charges.

On November 28, 2013 the Board declared Enbridge's existing rates interim effective January 1, 2014 pending final resolution of the matters in the proceeding.

The 11-day oral hearing began on February 20, 2014 and concluded on March 25, 2014.

The Board established a schedule for written argument[2] which had Argument in Chief filed on March 31, 2014, Board Staff Submissions on April 16, 2014, Submissions of the Parties on April 21, 2014 and Reply Argument on May 2, 2014.

Enbridge filed its Argument in Chief on March 31, 2014.

A record of all procedural matters and correspondence in this proceeding is available on the Board's web site.

The document herein represents Board staff's Submissions on Enbridge's Customized Incentive Regulation Proposal.

[2] The original schedule established at the oral hearing was extended at the request of SEC and CCC, which was supported by other intervenors.

Enbridge's Customized IR Plan

Enbridge is proposing a five-year customized incentive ratemaking ("IR") plan commencing January 1, 2014 which fixes the Company's allowed distribution revenue amounts ("Allowed Revenue") for each year of the five year term (2014-2018) based upon the Company's forecast for all cost elements within the plan (the "Proposed Customized IR Plan"). The elements of the Proposed Customized IR Plan, are outlined in Enbridge's pre-filed evidence[3] and summarized as follows in tabular form.[4]

	Components of IR Plan	**Details**
Items to be determined in the 2014 proceeding (EB-2012-0451)	Allowed Revenue amounts for 2014 to 2018	To be determined by summing together, for each year, the appropriate forecast level of operating costs, depreciation costs, taxes and cost of capital. These annual amounts are what Enbridge will be entitled to collect in rates each year.
	Volumes and Gas Cost related impacts for 2014	To be determined using the proposed updated Heating Degree Day ("HDD") methodology, as well as a gas volume forecast using existing methodologies for average use and large volume forecasts. Current gas cost forecasts to be used.
	Final Rates for 2014	Designed to allow full recovery of the 2014 Allowed Revenue.

[3] Ex. A2, Tab 1, Schedule 1, pp. 1-3.
[4] Adopted from table found at A2, Tab 1, Schedule 1, pp. 4-6.

	Components of IR Plan	Details
	Preliminary Rates for 2015 to 2018	Designed to allow full recovery of the 2015 to 2018 Allowed Revenue amounts, based upon current forecast of volumes and current forecast of gas costs. The preliminary rates are included to reflect current projections of the approximate impact of the IR plan in those years, but will be subject to update and approval in annual Rate Adjustment proceedings for 2015 to 2018.
Items subject to adjustment in 2015 to 2018	Average number of unlocks, volumes and gas costs related impacts, and amounts related to Pension, DSM and Customer Care costs	In advance of each year, Enbridge will provide: (i) updated forecasts of unlocks (active billed customers) using the customer addition forecasts approved in the 2014 and 2016 proceedings and other updated economic inputs; (ii) forecast volumes (applying the existing methodologies for HDDs, average use and large volume forecasts); and (iii) updated gas supply plan and gas costs. The updated data will be applied to the approved Allowed Revenue for each year to derive final rates for 2015 to 2018. The approved Allowed Revenue amounts each year will be updated to include recent forecasts of amounts related to Pension/OPEB, DSM and Customer Care/CIS costs.

	Components of IR Plan	Details
	Earnings Sharing Mechanism ("ESM")	To share weather normalized earnings between ratepayers and the Company on a 50/50 basis on earnings more than 100 basis points above Allowed ROE (calculated each year using the Board's ROE formula). The ESM will provide incentives for Enbridge to find further efficiencies and shares those benefits with rate-payers.
	Sustainable Efficiency Incentive Mechanism ("SEIM")	To provide incentives for Enbridge to produce sustainable efficiencies that will survive beyond the end of the IR plan term.
	Deferral and Variance Accounts	All existing deferral and variance accounts will be maintained (along with a small number of additional accounts) and a new variance account for the GTA project. There will also be a new variance account for 2017 and 2018 to capture differences in Allowed Revenue related to relocations projects and replacement mains projects resulting from pipeline inspections (including in-line inspections) and maximum operating pressure testing.

	Components of IR Plan	Details
Items subject to extraordinary adjustment	Z-factor	Allowance for recovery of unexpected cost increases or cost decreases with a revenue requirement impact of more than $1.5 million per year that are outside of management control. Updated wording for Z-factor eligibility is proposed, clarifying what was included in Enbridge's 1st Generation IR plan.
	Off-Ramp	Enbridge shall file an Application for review of the IR plan if its normalized earnings during any of the first 4 years of the IR plan are more than 300 basis points different from the Allowed ROE (calculated using the Board's 2009 ROE Formula).
Other Components	Performance Measurement	To track the Company's productivity initiatives, and operational and financial performance and benchmark against a peer group. Operational and financial performance will be reported at the end of the IR term, addressing a variety of performance metrics including customer satisfaction and a number of safety-related indicators. Tracking of productivity initiatives will be reported annually. Regular reporting through ESM proceedings and RRR filings will continue.

While the Company's original application had required that Enbridge's 2017 and 2018 Capital Budgets be determined midway through the IR term, the updated plan, which was filed on December 11, 2013, indicated that Enbridge would use the 2016 capital budget (except for the removal of $8.1 million in costs related to the Work and Asset Management System "WAMS") as a forecast of the Company's 2017 and 2018 spending requirements.

While the ROE in Enbridge's last IR Plan (2008-2012) was set at 8.39% and remained constant during the plan term, Enbridge is proposing to adjust its ROE in each year of the plan term as follows: 2014 9.27%, 2015 9.72%, 2016 10.12 %, 2017 10.17% and 2018 10.27%. Company witness Mr. Culbert indicated in oral testimony that the floating ROE alone accounts for $130.9 million of Enbridge's additional revenue as a result of using its Proposed Customized IR Plan versus a traditional I-X model.[5]

Enbridge said that it evaluated an inflation minus productivity (I-X) plan framework (using a revenue per customer cap that it operated under during the 2008-2012 period) in the context of its current circumstances and expected business needs over the coming years. Enbridge stated that it cannot continue with a similar I-X framework. Enbridge's evidence is that a number of changed circumstances in its operating environment present it with hurdles too large to operate under an I-X framework, including extraordinary capital spending pressures related to safety and integrity issues, very large capital projects related to system supply and work asset management, growing depreciation costs and uncertainty about future capital spending requirements.

Enbridge's evidence is that it has embedded productivity within the plan. Company witness Mr. Ryckman described the plan at the oral hearing as follows:

> So through I-X in the first generation plan, we had GDP IPI FTD *[sic]* as a proxy for where costs would be going, and then you had a productivity measure in there.
>
> What we're saying is that the traditional inflationary index doesn't provide what it needs to provide for us to meet the needs of our business and our customers. So we have structured the cost in that setting, the inflationary path, on a go-forward basis, not the traditional GDPI based on the needs of the business and the customers.
>
> The X part of it is already embedded within the numbers…[6]

In terms of distinguishing the current proposal from Enbridge's last IR plan, Company witness Mr. Fischer offered the following:

> The major difference between the first generation IR plan and ours is how

[5] Tr. Vol. 1, p. 90, lines 22-28.
[6] Tr. Vol. 1, p. 70 (line 27) – p. 71 (line 9).

> the revenue cap is determined.
>
> So the first generation IR model had a revenue cap, a revenue cap per customer, but it relied on the determination of a revenue cap, as does our customized IR plan, where the major area of difference is how we get there. They both require the need for productivity to be recognized in the determination of that revenue cap.
>
> With respect to the first generation IR plan, that was done through, effectively, the X, that scheduled factor that you mentioned earlier. That is how that was done in that plan.
>
> In our customized IR plan, what we're doing is we're relying on a forecast of cost elements, all of them, and we're embedding productivity directly into those cost forecasts.[7]

Enbridge's evidence is that the Proposed Customized IR Plan is informed by the Company's objectives, the Board's "Custom IR" option presented in the Board's Report entitled Renewed Regulatory Framework for Electricity: A Performance-Based Approach (the "RRFE Report")[8] and IR plans used in other jurisdictions.

In particular, Enbridge laid out the criteria which it says IR plans must satisfy as established in the Natural Gas Forum Report and the Board's statutory obligations in relation to the regulation of gas distributors (s. 2 of the OEB Act) and suggests that the Proposed Customized IR Plan will be appropriate if it meets these and the Company's own objectives. It then goes on to discuss the elements of the RRFE and says that:

> While the RRF Report is directed at electricity distributors, there are elements of the Electricity Distribution Rate-Setting policies section of the Report that are instructive to gas distributors. Of key importance is the Board's recognition of the challenges faced by some distributors because of significant capital spending requirements which may be "lumpy" in nature. To accommodate those challenges, the Board will provide options to electricity distributors to use different rate-setting methods that are best suited to their circumstances. Two of the three methods approved for electricity distributors ("incremental capital module" within 4th generation IR and "Custom IR") allow for recovery of capital expenses that are outside of the distributor's base revenue requirement, and would not otherwise be recoverable during an IR term. This is a clear recognition that meeting the Board's goal of ensuring reliable, sustainable distribution service may require high levels of capital spending, and this should be accommodated within an IR framework.[9]

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[7] Tr. Vol. 1, p. 174 (line 16) – p. 75 (line 3).
[8] Ontario Energy Board, October 18, 2012.
[9] Ex. A2, Tab 1, Sch. 1, p. 10.

Enbridge says that the main challenges that it will face in the coming years are capital spending pressures to maintain a safe and reliable system, other spending pressures, and productivity challenges.[10]

Enbridge relied on the evidence of London Economics International LLC ("LEI") which reviewed and considered IR plans used in other jurisdictions to set rates by forecasting costs and revenues for a number of future years and concluded that a "building blocks" approach, which it says is similar to the Proposed Customized IR Plan is used in the United Kingdom and Australia.[11]

Staff does not take issue with the concept of a 5-year customized IR approach to ratemaking, nor its application in the context of natural gas distribution rather than for electricity distribution as was explicitly contemplated in the RRFE Report. Staff's submissions on the proposal relate to whether a Custom IR framework is warranted in the current circumstances and whether, in putting forward its Proposed Customized IR Plan, Enbridge has filed all of the appropriate evidence in support of its proposal to allow the Board to determine whether the proposal is appropriate and will result in just and reasonable rates.

The RRFE and the Custom IR Framework

The renewed regulatory framework is described in the RRFE Report as "…a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers."[12]

The Board defines the following outcomes as appropriate for distributors: Customer Focus…Operational Effectiveness; continuous improvement in productivity and cost performance is achieved…, Public Policy Responsiveness…, and Financial Performance.[13]

The Report also defines three rate-setting methods: 4th Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (suitable for those distributors with large or highly variable capital requirements), and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). These rate-setting methods will provide choices suitable for distributors with varying capital requirements, while ensuring continued productivity improvement.

[10] Ibid., p. 15.
[11] Ex. A2, Tab 1, Sch. 1, p. 30.
[12] Supra., Note 7, p. 2.
[13] Ibid.

A. Appropriateness of Custom IR for Enbridge

The RRFE Report states that, "The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels."[14]

Enbridge describes the challenges that led it to file the Proposed Customized IR Plan as threefold: capital spending pressures to maintain a safe and reliable system, other spending pressures, and productivity challenges[15] with capital spending challenges begin "the most significant".[16]

It goes on to explain that it "…needs to increase capital spending over the next 3 years to address unavoidable issues such as safety and integrity issues, relocations, IT projects, and the GTA and Ottawa Reinforcement projects. In fact, Enbridge's total capital expenditures over the next three years are forecast to be approximately $2.0 billion, which represents a 53% increase over the total capital spent during the previous 3 years."[17]

In response to a Technical Conference Undertaking, Enbridge indicates:

> …the largest drivers of "lumpiness" in Enbridge's capital requirements over the forecast period are the GTA and Ottawa reinforcement projects and the WAMS project. Of the core capital, however, there are additional drivers of lumpiness, which are outlined in Ex. B2, Tab 1, Sch. 1, paragraphs 75-89. In particular, the variability caused by system integrity and reliability programs, as well as externally initiated projects like relocations are key drivers…There are several line items in the table that demonstrate how the Company went about its capital review. Lumpiness was largely stripped out of the spending requirements, as a result of certain costs being deemed variable costs.[18]

Enbridge defines "core capital" as "…all capital spending, except for three identified major projects: the GTA and Ottawa Reinforcements and the Work and Asset Management Project (WAMS)."[19] Enbridge also states that it is "at risk" for variable costs, meaning that these costs, which may or may not materialize have not been incorporated into the cost forecasts proposed in this application and will therefore be borne by the shareholder during the plan term. Examples of such variable costs would

[14] At p. 19.
[15] Ex. A2, Tab 1, Sch. 1, p. 15.
[16] TCU 2.2.
[17] Ex. A2, Tab 1, Sch. 3, p. 2-3.
[18] TCU 3.14, p. 1.
[19] Ex. B2, Tab 1, sch. 1, p. 3, para. 7.

include a plastic mains study, AMP fitting replacement, and MOP verification.[20] It follows that variable costs are not a factor for the purposes of evaluating costs included in the application.

Staff submits that the onus is on Enbridge, in applying the Custom IR framework provided in the RRFE Report, to establish through clear and convincing evidence that it has "significant large multi-year or highly variable investment commitments that exceed historical levels."

Staff discusses Enbridge's proposed capital forecasts in greater detail below, but in terms of the review of Enbridge's Proposed Customized IR Plan more generally, based on all of the evidence in the proceeding, staff submits that while the evidence does not support the contention that the *core* capital requirements of Enbridge are particularly variable throughout the term[21] the GTA and Ottawa reinforcement projects and the WAMS project are extraordinary capital requirements and more consistent with the application of the Custom IR framework.

B. Requirements Applicable to Enbridge's Proposed Customized IR Plan

In the RRFE Report, the Board indicates that, "Each rate method will be supported by: the **fundamental principles of good asset management**; coordinated, longer-term optimized planning; a common set of **performance** expectations; and **benchmarking**."[22] [Emphasis added.]

The Report goes on to say that for a Custom IR application the,

> …allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:
>
> - the distributor's **forecasts** (revenues and costs, including information and productivity);
> - the Board's information and **productivity** analyses; and
> - **benchmarking** to assess the reasonableness of distributor forecasts.
>
> Expected inflation and productivity gains will be built into the rate adjustment over the term.[23] [Emphasis added.]

[20] See J1.6 page 6 for a complete list of variable costs.
[21] Ex. A2, Tab 1, Sch. 3, p. 2, para. 4 (bar graph) (as updated Feb. 18, 2014); Ex. B2, Tab 1, Sch. P. 30, Graph 1; Ex. B2, Tab 1, Sch. 1, p. 3, Table 1; TCU 3.4; TCU3.5; Tr. Vol. 5, p. 77 (line 12) – page 78 (line 14).
[22] Supra., Note 7, at p. 10.
[23] Supra, Note 7, at pp. 19-20.

There is also an annual reporting requirement outlined in the Report whereby the Board monitors "…capital spending against the approved plan by requiring distributors to report annually on actual amounts spent"[24] and if the difference is significant the Board will investigate with the possible consequence of an early termination of the plan.

In staff's view, the starting point for a Custom IR plan is a comprehensive asset management plan which is directly linked to a robust forecast of the costs required to achieve the plan. In developing these forecasts, the utility should use the most sophisticated tools - in-house expertise, third-party engineering studies, and benchmarking to satisfy the regulator and ratepayers that the forecasts are reasonable and within the range of what would be expected for a utility of similar size and circumstances.

Board staff submits that under a Custom IR, a distributor should file robust forecasts of what is needed in terms of revenues, based on its thorough, comprehensive and well benchmarked cost projections and include projected productivity gains supported by well-designed and tangible initiatives which are measured, tracked and reported.

Staff will address each of the following required elements against the Enbridge Proposed Customized IR Plan, address the adequacy of the evidence tendered by Enbridge in support each of these elements and provide staff's position on each of the elements:

(a) Asset Management Plan;
(b) Forecasts;
(c) Productivity; and
(d) Benchmarking.

Staff will then provide its overall submissions and recommendation with respect to the Proposed Customized IR Plan.

[24] Supra, Note 7, at p. 20.

(a) Asset Management Plan

One of the underpinnings of the RRFE generally is robust asset management planning with a direct link to capital planning, which in turn allows the optimization and prioritization of capital expenditures.

The testimony of various Enbridge witnesses at the hearing makes clear that Enbridge's asset management planning is not fully matured in the sense that the Company is still learning and developing asset management as a tool.

> MR. SANDERS: Mr. Thompson, I will also offer that in the earlier version of the asset plan, that was the, I believe -- and I was not involved at the time, but the very first effort that Enbridge had made at doing a comprehensive asset plan. And the subsequent plan was the second iteration of that approach. As that process matures, it is developing more and more insight into the methods of determining risk and how we apply the risk to the existing assets.[25]

It also became clear to staff that the budgets are not directly linked to the asset management plan.

> MR. THOMPSON: …You say you can't budget these numbers for 2017 and 2018, but isn't that exactly what is done in these asset plans? I mean, I look at page 91 of the current asset plan and I see amounts for these years, 2017 and 2018.
>
> MS. LAWLER: So the budget process that Mr. Sanders referred to stripped the variable amounts out of the various line items. So what is reflected in the asset plan is inclusive of variable amounts.
>
> MR. SANDERS: I will offer, too, Mr. Thompson, that the asset plan approach at this stage is not a budgeting process. The asset plan is a process we go through to identify risk and reasonable expenditures over longer periods of time. I think you can appreciate that the farther out we go, the more variable those forecasts are going to be. It does offer guidance, it offers insight into what those amounts could be, but I wouldn't suggest it is actually a budget.[26]

And finally, the evidence reveals that not all assets are currently incorporated into the asset management plan.

[25] Tr. Vol. 5, p. 68, lines 4-13.
[26] Ibid. p. 73 (line 15) – p. 74 (line 4).

> DR. ELSAYED: Thank you. You talked about life cycle management. I want to understand what you meant by that term. You have asset plans, but do you have life cycle plans that go beyond that for the life of the asset?
>
> MR. SANDERS: That's the goal in the asset plan process. At the moment, we have not included, for example, all of our assets. We don't have our storage facilities in the asset planning process. The asset planning process has not yet brought in the operating and maintenance costs, for example. Our goal would be to incorporate all of that into the asset management tool and asset management process, to bring in that full life cycle view. So I would be looking at it literally from the time of installation to the time of abandonment and what are the costs associated over that entire life cycle for the assets.[27]

In short, in spite of the fact that Enbridge is a heavily asset based company with thousands of kilometres of pipeline, storage and other capital intensive assets, comprehensive asset planning is relatively new to the Company – at least in the form contemplated by the Custom IR planning process under RRFE.

Staff submits that the Proposed Customized IR Plan lacks a robust asset management plan, which should be linked to the capital budget and integrated into the Company's prioritization and optimization decisions over the plan term and beyond. The Board is therefore without this fundamental tool that is foundational to the Custom IR as envisaged by the Board in the RRFE.

While staff is cognizant of the fact that Enbridge is the first utility to present a rate plan under the Custom IR framework, staff is also mindful of the clear and express language in the RRFE which recognized the importance of robust asset management planning as a tool required for the utility and the Board to have confidence in a Custom IR application. It is also troubling that Enbridge seems to have chosen to take the guidance from the RRFE Custom IR framework that suited its needs without appropriately, in staff's submission, paying heed to the prerequisites and principles behind the framework.

If the Board does entertain Enbridge's Proposed Customized IR Plan as filed, it will be important, in staff's submission, for the Board to ensure that future filers that may seek guidance from the Board's decision in this first case understand the fundamental requirements of an appropriately structured Custom IR plan, including comprehensive asset management planning linked to its budget and operationalized to support the prioritization of decisions and the optimization of the utility's assets.

[27] Tr. Vol. 5, p. 162, lines 3-20.

(b) Forecasts

The RRFE Report indicates that the Board expects, among other things, that an application under the Custom method will include robust evidence of its cost and revenue forecasts. The application must also demonstrate the applicant's ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

Dr. Kaufmann's Assessment Report[28] states:

> PEG believes the importance of forecasts in Enbridge's Customized IR proposal raises (at least) three important issues. First, embedding forecasts in IR plans does not necessarily protect against risk, but it will affect the allocation of risk between customers and shareholders. Second, forecast-based IR approaches create potential incentive problems that are not encountered in standard, North American IR plans calibrated with historical information on industry input price and TFP trends. Third, Enbridge's Customized IR proposal does not confront these incentive concerns, which are evident in the experience with "building block" incentive regulation elsewhere.[29]

The Assessment Report goes on to describe in greater detail the basis for the concerns surrounding forecast risk in the current application and provides a description of the UK's experience with building block regulation and the evolution of the mechanisms implemented by Ofgem to address these issues.[30]

> It should be recognized that when Enbridge, CEA and LEI say that Enbridge's Customized IR proposal is an example of "building block" regulation, they are not referring to the building block model currently used to regulate UK gas or electricity distributors, which includes an information quality incentive designed to reduce distributors' ability and incentive to game capital cost forecasts. Instead, they are harkening back to a version of building blocks that Ofgem abandoned nearly a decade ago because of its poor incentive properties. The Enbridge Customized IR plan creates the same perverse *ex ante* incentives to inflate capital cost projections as the early UK building block plans. Because the Company's capital expenditure *forecasts* are not supported by independent and external benchmarking evidence, the inherent incentive to inflate capital

[28] Ex. L, Tab 1, Sch. 2.
[29] Ibid., at p. 18.
[30] Supra, note 24, pp. 21-22.

> expenditure forecasts under Enbridge's Customized IR proposal can generate unreasonably high prices and shift risks to customers.[31]

The Assessment Report also addresses Enbridge's claims that the earnings sharing mechanism ("ESM") will protect customers. In particular, PEG says that while the ESM reflects the relationship between forecast and actual costs, it does not address whether the forecasts embedded in the plan are reasonable. In fact, it can actually create incentives for Enbridge to act unreasonably and inefficiently to avoid the sharing under the ESM and potentially trigger the off-ramp which would be triggered under the current Customized IR Plan Proposal if Enbridge's weather-normalized ROE differs from its approved ROE by +/- 300 basis points. The ESM as currently proposed also puts customers fully at risk for the first 100 basis points of Enbridge returns above the allowed ROE.

Staff shares the concerns expressed in the Assessment Report in this regard and the view that while the ESM may mitigate the impact of over forecasting "…the Board can only be assured that customers are not paying for excess cost forecasts if there is objective, external evidence that supports the efficiency of the cost *projections* themselves… "

(c) Productivity

All incentive-based ratemaking frameworks at the Board are premised on the utility achieving productivity and efficiency gains throughout the IR plan term and the RRFE framework is no exception.

One of the stated outcomes on which distributors are required to report under any rate-setting method under the RRFE is "Operational Effectiveness" which is defined at a high level as "…continuous improvement in productivity and cost performance is achieved; and utilities delivery on system reliability and quality objectives."[32] For 4th Generation IR, productivity continues to be an X factor comprised of industry TFP growth potential and a stretch factor. For Custom IR the reference is to "the Board's inflation and productivity analyses".

The RRFE Report also provides: "The Board is satisfied that the Custom IR process will be sufficiently rigorous that an assessment of the adequacy of past and future

[31] Supra, note 24, p. 21.
[32] At p. 2.

productivity levels can be made and the results of that assessment can be incorporated into the distributor's future rates."[33]

Staff submits that productivity is a fundamental premise of Custom IR and therefore Enbridge's Proposed Customized IR Plan requires real, tangible and significant productivity as part of the plan.

The Company's evidence is that it has embedded $172.5 million worth of productivity in the five-year budget.[34] This is about 1.3% of total revenues over the plan term.

Enbridge has outlined all of its cost reduction commitments which include reductions to its original budgets in the O&M and capital areas. Enbridge has termed these collectively as "cost commitments".[35]

Further detail with respect to this evidence and staff's submissions are provided under a separate section below. For the purposes of evaluating Enbridge's Proposed Customized IR Plan model, however, Staff submits that the evidence related to the reductions to budgeted capital and O&M amounts which amount to $172.5 million do not represent productivity within the plan. Rather, this is a budget presentation that may, or may not, result in (or force) productivity and efficiency measures within the Company based largely on whether and to what extent the Company finds other cost-cutting measures that would achieve the same end.

Enbridge repeatedly indicated that it does not currently have a list of proposed programs, products or other initiatives that are intended to be implemented to achieve productivity and efficiency gains during the plan term. It also did not explain how, from an "RRFE" perspective, it intends to achieve the outcomes that are central to that framework.

In staff's submission, in the IRM context and for Custom IR in particular, the Board should be looking for something more tangible in terms of productivity than simply a "baked in" amount that reflects a downward revision in the Company's own cost forecasts and has no obvious relationship either as an input or output to productivity or efficiency improvements. The Board should continue to expect actual productivity and efficiency programs which are intended to achieve results incremental to any gains achieved in the previous term and on a sustainable basis.

And while the Sustainable Efficiency Incentive Mechanism ("SEIM") is an interesting and innovative proposal for the purposes of potentially achieving sustainable efficiencies (Staff's concerns with the SEIM are further discussed below), without any

[33] At p. 70.
[34] J1.6 page 2 of 7.
[35] J1.6.

evidence of tangible efficiencies or productivity initiatives or programs in either the short or the long-term, nor a team or a corporate approach to achieving them, Staff submits that the SEIM is premature and therefore inappropriate given the circumstances of this case. Without a culture of continuous improvement, the concept of Enbridge "upping its game" by "adding" a SEIM is simply not supported by the evidence.

Staff recommends that the Board impose an external stretch factor or "consumer benefit" in the form of a percentage of revenue requirement. The details of this recommendation are discussed further below.

Staff also recommends that the Board require Enbridge to identify programs and the outcomes which those programs are intended to achieve prior to the commencement of the plan term, which are created for the specific purpose of achieving quantifiable productivity and efficiency gains and to track and report on those programs on an annual basis. This reporting mechanism is already included as a feature of the application[36] and is likely sufficient as proposed, but the programs themselves and the targets to be achieved are missing.

(d) Benchmarking

In the RRFE Report in Table 1 which is entitled "Rate-Setting Overview – Elements of Three Methods" there is a column entitled "Custom IR" and under the row entitled "Role of Benchmarking" the table states: "Distributor-specific rate trend for the plan terms to be determined by the Board informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's information and productivity analyses; and (3) ***benchmarking to assess the reasonableness of the distributor's forecast.***" [Emphasis added.]

Further, in the Board's Rate Setting and Benchmarking Report, the Board states:

> …the Board has decided to rely solely on the econometric model to assign stretch factors to distributors. In general there is lack of support amongst stakeholders for the use of peer groups and the Board finds the reasons cited compelling. In particular, stakeholders persuasively argued that there are too many variables that can affect distributor costs to be confident in peer group allocations…it should be easier for a distributor to identify its relative cost efficiency, act to improve it, move up the efficiency ranking…[37]

[36] Ex. A2, Tab 1, Sch. 1, p. 6.
[37] At p. 20.

Staff therefore submits that the Board specifically contemplated as part of the RRFE that those utilities filing for a Custom IR plan would be required to benchmark their forecasts of revenues and costs. Further, the Board has considered, at least in the electricity distribution context, what type of benchmarking provides the best information for the Board in assessing distributor costs and has indicated that it will rely on econometric benchmarking.

During the course of the oral hearing, Mr. Coyne confirmed that the share of Enbridge's total costs attributable to capital expenditures was 66 per cent in 2011 and an average of 68% over the 2000-2011 period.[38]

The Report[39] prepared by Concentric Energy Advisors Inc. ("CEA") and filed by Enbridge as part of its pre-filed evidence concludes that, "On balance, the benchmarking analysis indicates that Enbridge is among the most efficient of its US peers in most categories measured."[40] However, Mr. Coyne confirmed in oral testimony that the conclusion is based entirely on analyses that do not involve measurements of capital costs and that in fact, one of the exceptions to the overall conclusion is the measurement of "net plant per customer",[41] which Mr. Coyne had earlier explained was one of the ways CEA had benchmarked Enbridge's capital costs.[42]

Mr. Coyne also acknowledged that CEA did not assess the capital plan for reasonableness from a "bottom-up basis", but only from the I-X analysis that CEA did. Staff takes this and the totality of the evidence from CEA to mean that other than a comparison of

"net plant per customer" which is provided in the CEA Report[43] at $1900 for Enbridge and puts it 21st out of 26 distributors in the study. CEA did not conduct an assessment of Enbridge's capital costs in the current proceeding in any substantive way even though we know capital represents approximately 65% of the total costs in this case.

The Board must have confidence in the capital forecasts provided in any rate case, but certainly here, where Enbridge seeks revenues based on capital forecasts which are projected out for five years.

CEA conducted a benchmarking analysis which measures Enbridge's performance against an industry study group using a series of metrics that quantify the relative

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[38] Tr. Vol. 3, p. 1, lines 15-18.
[39] Ex. A2, Tab 9, Sch. 1.
[40] Ibid., at p. A-19.
[41] Tr. Vol. 3, p. 97 (line 26) – p. 98 (line 10).
[42] Tr. Vol. 3, p.72, lines 17-24.
[43] At p. A-6.

efficiency of Enbridge in terms of its capital investment and O&M expense profiled (Ex. A2, Tab 9, Sch. 1).

In its testimony, CEA says that it benchmarked Enbridge's capital costs in two ways: Total Factor Productivity ("TFP") analysis and net plant.[44]

While the Company says that it has conducted benchmarking, Staff submits that the benchmarking conducted was inadequate for several reasons.

i. Inappropriate or Irrelevant Criteria in Selecting Study Group
ii. Scope of Benchmarking
iii. Benchmarking Methodology
iv. Historical versus Projected Costs

Staff will address each of these areas of the benchmarking evidence in turn.

(i) Inappropriate/Irrelevant Criteria in Selecting Study Group

In its oral testimony, Mr. Coyne indicated:

> …we felt it was important to base our benchmarking and productivity analyses on an industry study group of companies that are representative of Enbridge's operating circumstances.
>
> Study group companies were carefully selected based on criteria that identified companies similar to Enbridge, as measured by factors that are likely to affect costs and productivity, while allowing for a sufficient number of companies in the study group to ensure that the analyses would be robust and provide an appropriate perspective for industry comparisons.[45]

CEA used four criteria in selecting the study group:

- Similarity of operations to Enbridge
- Similarity of weather conditions to Enbridge
- Similarity of size to Enbridge
- Data availability[46]

In its Assessment Report PEG addresses the selection of the peer group and concludes that while the "Similarity of weather" criterion would have an impact on gas

[44] Tr. Vol. 3, pp. 71-73.
[45] Tr. Vol. 3, p. 45, lines 1-11.
[46] Ex. A2, Tab 9, Sch. 1, pp. 21-22.

consumption, it is …"irrelevant in a study that (like CEA's) compares unit OM&A costs per customer across utilities."[47]

In fact PEG goes on to say that "…we cannot recall a single PEG study finding a statistically significant relationship between a gas distributor's costs and heating degree days in its territory."[48]

PEG says that the consequence of including the weather related criterion is that nearly all the rapidly-growing US gas distributors are excluded from the study group. Further since older systems in the US constructed with cast iron and bare steel main are "…disproportionately (indeed, almost exclusively) in the northern half of the country",[49] the cold weather criterion includes a number of distributors that are experiencing issues with gas leaks and are therefore incurring operating costs that are substantially higher than those for utilities with nearly 100% polyethylene systems (like Enbridge).

CEA indicates that Enbridge's customer growth rate of 2.6% "…is higher than all other companies in the industry study group."[50] The details behind that statement are provided in a response to a Board Staff interrogatory[51] which includes a table that shows the relative customer growth rates of the other companies in the study group shows that, with the exception of Northwest Natural Gas Company at 2.55%, Puget Sound Energy, Inc. at 2.41% and Questar Gas Company at 2.39%, Enbridge's customer growth rate over the 2000-1011 period is significantly higher than all of the others in the study group whose customer growth rates ranges from -0.40% to 1.96% with 17 of 25 of peers having customer growth rates below 1% and 9 of those having customer growth rates of less than 0.5%.

In oral testimony, Mr. Coyne admits that Enbridge is an outlier in CEA's study group.

> MS. SEBALJ: And then when we get to figure 11, you have plotted all of the companies, I believe, or 28 of them, onto what I would call a scatter plot. And that is how you chose the seven-peer subgroup; is that correct?
>
> MR. COYNE: That's right. When we looked at the array of companies that we had, we recognized that by virtue of the operating metrics that I just described, that Enbridge -- let me just go back. I think it makes the point visually quite well.
>
> If you go to figure 5 on page 26 of 125, you can see that Enbridge is the third-largest utility in this proxy group. And the -- I don't believe that we show customer growth here, but there is other evidence of that on

[47] Ex. L, Tab 1, Sch. 2, p37.
[48] Ex. L, Tab 1, Sch. 2, p. 38.
[49] Ex. L, Tab 1, Sch. 2, p. 39.
[50] Ex. A2, Tab 9, Sch. 1, p. 31.
[51] Ex. A1, EnbridgeI.STAFF.13.

record that also shows -- and also, of course, we picked it up in our productivity analysis, because we're measuring customer growth there -- they are among the fastest growing utilities.

So in our minds -- and I think this is borne out by other analysis as well -- a larger utility that's a faster growing utility should have two advantages over others. It should have some advantages in terms of economies of scale and by virtue of faster customer growth, that assisted from a TFP standpoint, because you are measuring the difference between output and input, and generally speaking, faster growing utilities will have higher TFP indices as a result of the math involved.

So for that reason -- to go back to your figure 11 -- as you point out, what we did there is we further segmented our universe of companies to choose those that were the fastest growing and the largest, and that was the basis of developing this seven-company subgroup that represented a stronger target from an efficiency standpoint for Enbridge.

MS. SEBALJ: And isn't it fair to conclude, looking at figure 11, that Enbridge is an outlier? It is actually unlike any of the firms that are in this peer group, including the seven-peer subgroup?

MR. COYNE: Well, they are the third-largest and the fastest growing over this period of time, close to Northwest Natural. And it was based on that analysis that we decided that we needed a smaller subgroup to best represent them. **We made the same observation.**

MS. SEBALJ: But isn't it the case that there are utilities out there with -- and this scatter plot, just for the record, is average customer count growth rate against average number of customers.

And we know, do we not, that Enbridge's growth rate is 2.6 percent on average, from 2000 to 2011?

MR. COYNE: That looks about right, based on the chart, yes.

MS. SEBALJ: And we know that 17 of the 25 that are plotted on this have growth rates less than 1 per cent?

MR. COYNE: I didn't make that count, but I will -- I guess I will trust your math.

MS. SEBALJ: Well, it's not even math. It is just a visual.

MR. COYNE: Okay. I will trust it.

MS. SEBALJ: And so is it not the case that if we go back to the selection criteria, which were the four criteria, that it is possible to find a peer group that is more similar to Enbridge than this particular peer group?

MR. COYNE: Is that a question? Is it possible to find?

MS. SEBALJ: Yes.

MR. COYNE: This is the North American sample that we have to work with. I suppose one could go to another continent, but then I think you start to introduce problems in terms of the compatibility of the data.

You have -- generally speaking, you want to choose a subgroup that is large enough so that you have a robust data set that you can draw inferences from.

If you were to make it too much smaller than this, the chance for any one company to unduly influence those results becomes very large. So we're getting towards the edge of what we consider to be a viable subgroup for analysis on that basis.

And I should also say that, mind you, we have measured -- we've measured Enbridge's productivity individually and against the subgroup, so we have some basis of comparison there. And by virtue of looking at productivity, the difference between companies that are growing at different speeds and the relationship with the outputs that they consume, the TFP analysis itself helps you sort through that. At least it gives you a sense of -- I guess it gives you a perspective on that issue.

But by narrowing it down to the top seven, we felt as though this subgroup at least was certainly more representative than using an entire universe of all US companies, or some broader subgroup.

MS. SEBALJ: If you were before a regulator, looking at National Grid, would you not have excluded Enbridge as an outlier?

MR. COYNE: I guess I'm not sure of that. The same considerations would have helped. You know, what companies can we find that will bring us closest to the National Grid experience?

They're in New York, they're large, they're serving a large urban customer base. In that sense, I think I would -- I would be inclined to want to keep them for that reason.[52] [Emphasis added.]

In attempting to explain the results of Enbridge's ranking against the CEA study group provided in TCU 1.11, Mr. Coyne says:

> Specifically, since 2001, Enbridge has replaced approximately 1,000 km of leak-prone pipe; currently, virtually none of Enbridge distribution mains is leak prone. In contrast, most US distributors, including the study group companies, have been replacing leak prone pipe at a slower rate. Also

[52] Tr. Vol. 3, p. 89 (line 14) – p. 92 (line 28).

> Enbridge's 2001 to 2011 customer growth rate, 2.6% was higher than all other companies in the industry study group.[53]

Staff submits that the evidence clearly shows that Enbridge is an outlier within the CEA study and this fact makes the analysis derived from the study group selected by CEA of questionable value.

In addition to the fact that Enbridge is an outlier in its own benchmarking analyses the evidence also fails to explain why certain utilities were not included in the study group.

For example, in oral testimony Mr. Coyne clarifies that the six Canadian companies initially included in the group of 34 peers in the study group[54] were ultimately removed from the study for the purposes of the productivity analysis. He indicates that while they were used for the first benchmarking report that was done for the 2013 rebasing case, there were data collection issues which he describes as a "challenge". He says "We had to call these companies and ask for data that wasn't in the public domain, and we couldn't legitimately do that for the entire period of time. So we only benchmarked the Canadian companies for that one year."[55]

The result, as confirmed in Mr. Coyne's oral testimony is that there is no benchmarking against a Canadian utility in CEA's Report.[56]

In particular, ATCO, Fortis BC, Gaz Metro, Manitoba Hydro, Sask Energy Inc. and Union Gas Limited were not included for the productivity analysis, nor in any of the capital or other benchmarking analyses provided in the CEA Report. In other words, CEA relies entirely on its 2011 data to say that its analysis includes Canadian utilities in its benchmarking "other than productivity". Responses to further probing into the question of why CEA had not availed itself of certain Union Gas Limited data were confusing and unconvincing.[57]

The lack of evidence provided for any year other than 2011 for any of the benchmarking analyses conducted by CEA is troubling to Staff. No detail was provided as to the challenge regarding the collection of data from these Canadian utilities, but the inherent benefit of the information, had it been accessed, is clear. For example, Union Gas Limited would have, in staff's submission, met CEA's criteria and as a result would have been included in the peer group. The absence of this data is especially troubling,

[53] At p. 6.
[54] CEA Report, Figure 4, p. 19.
[55] Tr. Vol. 3, p. 85.
[56] Tr. Vol. 3, p. 86, lines 3-21.
[57] TCU 1.10.

particularly in light of how much Enbridge stands out as an outlier within the study group ultimately selected by CEA (as shown in Figure 14 of CEA's study).

(ii) Scope of Benchmarking

The "scope of benchmarking" refers to the scope of activities covered by the benchmarking analysis. In general, benchmarking can utilize 'total' or 'partial' performance metrics. Total benchmarking metrics include total cost levels or total unit cost (*e.g.* total cost divided per customer served). Partial benchmarking metrics include partial costs (*e.g.* OM&A costs) or partial unit costs (*e.g.* OM&A cost per customer).

The Board has expressed a clear preference for total cost benchmarking. In the "Role of Benchmarking" section of the RRFE Report, the Board says: "benchmarking models will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcome, including: total cost benchmarking; an Ontario TFP study; and input price trend research."[58] It is noteworthy that the Board specified total cost benchmarking and an Ontario TFP study as separate components of its empirical benchmarking program.

A further issue is that while CEA presented information on Enbridge's relative OM&A and capital cost performance, based on the explanation that follows, this evidence represents partial benchmarking analysis and neither constitutes total cost benchmarking.

Benchmarking is designed to make inferences on cost efficiency. Inferences can be made on either efficiency at a given point in time (*e.g.* Enbridge's cost efficiency in 2011) or on changes in efficiency over time. In Ontario, nearly all regulatory applications of benchmarking have focused on making inferences on efficiency at a point in time rather than over time. For example, benchmarking has been used to assign stretch factors in Price Cap IR for electricity distributors. The benchmarking model used for this purpose examines the relationship between a distributor's actual cost *level* and its predicted cost *level* and therefore addresses each distributor's cost efficiency at a point in time.

In the passage from the RRFE cited above, the Board distinguishes "an Ontario TFP study" from "total cost benchmarking" because TFP growth includes more than changes

[58] At p. 60.

in *efficiency*. Efficiency change is only one of the components of industry TFP growth.[59] The implication is that comparing changes in TFP growth for two utilities (or between Enbridge and a multi-company aggregate) *is not total cost benchmarking*. The reason is that cost benchmarking is designed to make inferences on efficiency, but TFP growth reflects a number of factors other than change in efficiency *per se*.

While CEA did estimate growth for Enbridge and different definitions of the gas distribution industry, any comparisons of these growth rates are *not* capable of isolating how much more efficient Enbridge is (or is not) relative to the industry. CEA's simple comparisons of TFP growth for Enbridge and the gas distribution industry do not account for the impact of scale economies on TFP growth for Enbridge or the industry. These TFP trend comparisons therefore do not provide a reliable inference on the efficiency change of Enbridge relative to the industry. This issue is particularly important for Enbridge, because it has the most rapid output growth of any distributor in CEA's sample (2.6% per annum, compared with 0.64% output growth per annum for the overall industry excluding the three other sample companies who also experienced relatively rapid output growth). Because its analysis does not differentiate between economies of scale and efficiency gains, or account for them separately, CEA's comparison of TFP growth for Enbridge relative to the industry almost certainly overstates Enbridge's actual efficiency gains compared to the industry.

At the oral hearing, Mr. Coyne was asked about CEA's TFP analysis and confirmed that the TFP results presented showed a rate of change in TFP over the period of 2000-2011 rather than a TFP *level* for Enbridge.

> MS. SEBALJ: And if I just take you for a moment to that, you have taken me to a different piece of my cross, but I am happy to go there. In your study, if we go to the tables that you referred to this morning, the figures -- I want to say 14. Yes. Figure 14, which is at page 34 of 125. Sorry. We are there, but I am not there. Just one moment. Here we go. When I look at this table, I see that you've -- it is entitled: "TFP index results table for Enbridge, the industry study group, and the seven-company subgroup". And I will go back to the -- how you selected the peer groups in a moment, but -- and it is from 2000 to 2011, which I assume was chosen deliberately to reflect the periods of time over which Enbridge has been in some form of PBR/incentive ratemaking. But if we look at the row 2000, at the very top of the table, all three groups show 100. And that was chosen essentially as a placeholder; is that correct?
>
> MR. COYNE: Well, it is the base of an index, the starting year of the analysis. We are trying to measure the change in net index over time from a common base, which is the year 2000.

[59] See Appendix One of the *Concept Paper* from PEG provided in response to Ex. I.A1.Staff.EnbridgeI.5.

> MS. SEBALJ: Right. So it's the change over time, which is actually TFP growth, as opposed to TFP level; isn't that correct?
>
> MR. COYNE: That's correct.
>
> MS. SEBALJ: And so you are not actually measuring Enbridge's TFP vis-a-vis these groups? You are merely measuring how it has changed over time as compared to these groups?
>
> MR. COYNE: In order to do that, we measure TFP for Enbridge as well as the groups, and then compare them to them. So we're measuring their -- using the same exact methodology, we're measuring their change in the growth of the TFP index over the same period of time, with Enbridge data, as opposed to the utility data for the seven or the 25 companies.
>
> Does that go to the thrust of your question?[60]

A fair number of questions followed to clarify this point, but it is Staff's submission that the evidence cannot be taken to provide a measure of Enbridge's absolute productivity over time, but rather that it can only be used to measure the rate of change of productivity.

This position is supported by the oral testimony provided by Dr. Kaufmann on the point.

> DR. KAUFFMAN: Just to follow up on what Mr. Coyne was saying, yes, it is true that whenever you do one of these analyses, you do have to build up an initial capital stock.
>
> But for the purpose of this analysis, the only application, the only reason you do that is to measure the change in the company's own capital stock, or the change in the company's capital, are the change in aggregate's capital stock over time.
>
> This is entirely a trend-based analysis. And I disagree with Mr. Coyne; you can't draw any implications on the absolute level of any -- of Enbridge or any of the aggregates here, because of the fact they're all 100 in 2000, and that's not a value that is measured.
>
> It isn't the case that Mr. Coyne developed some sort of process, and he just happened to measure a value of 100 for Enbridge and these aggregates. This is an arbitrary starting point, which is fine, because the focus of the analysis is just to measure changes past that point.[61]

[60] Tr. Vol. 3, pp. 74 (line 22) – 75 (line 4).
[61] Tr. Vol. 3, p. 83 (line14) – p. 84 (line 3).

Based on this evidence, Staff submits that CEA's TFP "analysis" is of limited use as it does not speak to the total productivity of Enbridge at any given point in time, but rather measures the relative rate of change in total productivity of Enbridge over time as compared to the seven peer sub-group that CEA selected as part of its analysis.

CEA also does not provide any evidence on the *level* of total cost efficiency for Enbridge. CEA presented some metrics on Enbridge's relative OM&A costs and presented other metrics involving Enbridge's relative capital costs.

Dr. Kaufmann's Assessment Report explained why this is in fact an example of partial rather than total performance benchmarking:

> CEA's benchmarking metrics are partial unit costs; that is, they take partial measures of Enbridge's 2011 costs (such as its OM&A costs) and divide them by a single output measure (either customer numbers served or delivery volumes) to construct partial unit cost measures. CEA computes several partial unit cost measures for Enbridge, but it does not attempt to aggregate them into more comprehensive unit cost indices, nor does it consider potential tradeoffs among the partial indices (*e.g.* whether higher net plant value per customer is associated with lower OM&A costs per customer).[62]

A comprehensive or total cost metric includes both capital and OM&A costs. Presenting OM&A and capital cost metrics separately increases the number of partial cost indicators from one to two; it does not create a total cost indicator. It is only by aggregating partial indicators (in some well-defined fashion) into a single metric that a measure of a firm's comprehensive or overall cost performance can be developed.

In order to compensate for this lack of total cost metric, CEA was asked in TCU 1.11 to provide the sum of capital costs plus OM&A costs for each company in CEA's industry study group and for the industry as a whole (the twenty-five companies) and for Enbridge, and divide by the total customers for 2010 and 2011.

CEA provided these calculations on average for the 2000-2011 period and the annual number for each of these years (including 2010 and 2011) in an appendix.

Dr. Kaufmann also undertook to do the calculations using the data previously provided by CEA in advance of the Technical Conference. A supplementary response to the undertaking was filed as TCU 1.11x. The results, which are presented as unit cost rankings, show that Enbridge's total cost per customer was $470 in 2010. This ranked

[62] At p. 32.

Enbridge 15th of the 26 gas distributors in that year. Enbridge's total cost per customer was $530 in 2011, which ranked Enbridge 21st out of the 26 gas distributors.

Staff is concerned that Enbridge did not file any total cost benchmarking in its pre-filed evidence and had to be asked to provide the evidence as an undertaking. Acceptance of Enbridge's partial cost benchmarking in CEA's report will, in Board staff's submission, send a signal to electricity distributors that plan to file Custom IR applications that partial cost benchmarking evidence is acceptable. This could lead to a situation in which complex, multi-year Custom IR applications are supported using less comprehensive and rigorous benchmarking evidence than the benchmarking model approved for the less complex, Price Cap IR option.

(iii) Benchmarking Methodology

Another concern is the benchmarking methodology used to support Enbridge's Customized IR proposal. CEA used a peer group benchmarking approach, in which Enbridge's OM&A unit costs are compared to those of a group of gas distributors deemed to be peers. Essentially, CEA considers a North American gas distributor to be a peer of Enbridge if it: 1) serves 500,000 customers in the US or 150,000 customers in Canada; 2) its heating degree days are within +/- 45% of Enbridge's heating degree days; and 3) has high quality data.

In the RRFE Report the Board indicates that it does not have confidence in peer group benchmarking methods used in 4th Generation IR and rejects the use of peer groups to establish cohorts for assigning stretch factors to electricity distributors.

This was brought to the attention of CEA in an interrogatory;[63] however, CEA responded that the Board's expressed concerns were "irrelevant" for Enbridge because they applied only to using peer groups to assign stretch factors.

CEA is correct that in the RRFE Report[64] the Board decided that it would:

> …rely solely on the econometric model to assign stretch factors to distributors. In general, there is lack of support amongst stakeholders for the use of peer groups and the Board finds the reasons cited compelling. In particular, stakeholders persuasively argued that there are too many variables that can affect distributor costs to be confident in peer group allocations. The Board notes that unit cost comparisons can still be done without pre-defining peer groups. The Board expects that the use of one

[63] Ex. I.A1.EGDI.CME.1.
[64] At p. 20.

> benchmarking model to produce a single efficiency ranking be more transparent and understandable for customers and distributors. Consequently, it should be easier for a distributor to identify its relative cost efficiency, act to improve it, move up the efficiency ranking and be rewarded through the annual group assignments by moving into a more efficient group. Benchmarking is further discussed in Chapter 3.

However, Chapter Three of the RRFE Report provides a more general statement of how the Board intends to use benchmarking to set rates. This Chapter precedes the Board' discussion of the assignment of stretch factors and shows that the Board's concerns with peer group benchmarking are not restricted to its use in assigning stretch factors for distributors:

> In its RRF Report, the Board concluded that benchmarking will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including total cost benchmarking for the 2014 rate year. Future work will involve comprehensive benchmarking (i.e., model(s) that combine standards for customer service, including distribution system reliability, and cost performance).
>
> The Board has determined that PEG's econometric model will be used for benchmarking distributor cost performance and, as previously noted, for informing the Board's annual assignment of stretch factors to distributors…This benchmarking model will be used to predict each distributor's total costs, and the distributor's actual total costs will be compared to the econometrically derived predicted value.[65]

CEA elected to use the benchmarking approach which the Board has explicitly indicated is problematic. CEA says that the data are not available or are inadequate to do the gas distribution benchmarking that staff suggests is required.[66]

CEA's concerns around data availability are not shared by Dr. Kaufmann who indicated in response to an interrogatory:

> In utility regulation, it is prudent to "never say never." There may be extreme situations where there is so much missing or inaccurate data that the only feasible benchmarking measures that can be constructed are simple, partial unit cost metrics. There is no need to rely on simple

[65] At pp. 23-24.
[66] Technical Conference Tr. Jan. 16, 2014, at. p. 125.; Tr. Vol. 3, p. 98 (line 21) – p. 101 (line 5); Ex. I.A1.EGDI.Staff.17.

> benchmarking techniques for either Enbridge or the US gas distribution industry, where ample, high quality data are available.[67]

While Staff's concern about the benchmarking methodology used by CEA is less pronounced than with the scope of CEA's benchmarking analysis, CEA's failure to acknowledge or address the Board's concerns with peer group benchmarking is problematic. Because CEA did not respond substantively to these concerns, Staff submits that the Board must address this issue and provide a signal to regulated distributors that peer group benchmarking is not the preferred method for benchmarking costs as part of a customized IR application before this Board.

(iv) Historical versus Projected Cost

Staff's largest concern with Enbridge's Customized IR proposal is that it does not provide any independent benchmarking support for the Company's forecasted capital expenditures proposed under the plan. CEA's benchmarking study is entirely backward looking. CEA has admitted[68] that it did not undertake any analysis of the reasonableness of Enbridge's proposed capital expenditures under the Customized IR plan.

As noted in the Assessment Report and in the "Forecast" section of this submission, this is a significant deficiency, because utilities under "building block" plans have inherent incentives to inflate their capital expenditures. In evidence provided by Dr. Kaufmann and noted above[69] he cites Ofgem as saying that gas distributors have incentives to inflate their capital expenditures under building blocks, and indicates that Ofgem has responded to this propensity through benchmarking and incentive mechanisms that mitigate distributors' incentives to present excessive capital forecasts.

This is the first time the Board is considering a Custom IR application, and Staff submits that it is important for its review to take heed of the lessons from building block/Custom IR regulation overseas. This experience clearly shows that regulators rely on benchmarking evidence to assess the reasonableness of capital expenditures under a Custom IR plan (in addition, in some cases to third party engineering assessments of the asset management/capital plans).

In the absence of such benchmarking, the Board has no independent, third party evidence against which to judge the Company's proposals; all it has is the Company's

[67] Ex. I.A1.Staff.EGDI.7.
[68] Tr. Vol. 3, p. 98, lines 11-20.
[69] See Note 24-27 of the "Forecasts" section of this submission.

own statements of what it has done to ensure that its forecasts are reasonable. Even if companies are making their best efforts to present reasonable forecasts, the distributor is an interested party in the proceeding. Its capital expenditure forecast will inevitably be influenced and shaped by its own interests, which may differ from the public interest. Staff therefore submits that the Board should be wary of simply accepting a Company's forecasts as being an objective representation of its required capital expenditures. At the very least, benchmarking can provide a needed "assessment" or "check" on the reasonableness of those forecasts. The experience with building block regulation also shows that it is not appropriate to rely solely on the Company's internal projections as the basis for allowed capital expenditures.

In discussing investment plans in the RRFE Report, the Board says, "the onus, however, remains on the distributor to provide the data, information and analyses necessary to justify the forecasted costs that are the basis for the distributor's proposed rates."[70] And in the Board's conclusions regarding investment plans, it writes that "the Board sees merit in receiving the evidence of third party experts as part of a distributor's application, or retaining its own third party experts, in relation to the review and assessment of distributor asset management and network investment plans (along with other evidence filed by the distributor)."[71]

Taken together, Staff interprets these and the more general statements with respect to benchmarking from the RRFE Report and cited above to indicate that the Board expects Custom IR plans to include one or both of: 1) benchmarking studies that assess the reasonableness of the cost forecasts presented in a Custom IR proposal; and 2) third party, expert opinion that reviews and assesses the network investment plans contained in a Custom IR proposal. Enbridge's pre-filed evidence does not include any comprehensive or total cost benchmarking studies to support its cost forecasts, or any third party reviews and assessments of its investment plans.

Staff submits that Enbridge's Customized IR Plan Proposal is not supported by adequate or appropriate benchmarking or third party expert evidence.

While Enbridge says that it has been guided by the Board's RRFE Report which applied to electricity distributors, it has not been guided by the Board's articulation of a need for comprehensive benchmarking of costs and revenues, nor of the Board's reliance on econometric benchmarking.

Again, Staff finds it troubling that while Enbridge has used the RRFE for its benefit in some areas, it has neglected to abide by or address deviations from the Board's express requirements or preferences in other areas.

[70] RRFE Report, p. 36.
[71] Ibid., p. 37.

C. Balance of Risk and Reward

Staff has articulated its concerns with Enbridge's qualification for a Custom IR based ratemaking framework and its adherence to the elements of such a framework.

In addition, it is not, in Staff's view, appropriate for Enbridge to file a rate making plan in the nature of a Custom IR for which it is providing internally derived forecasts and then use multiple regulatory levers, some of which would otherwise not be available to non-Custom IR filers, for the purpose of managing or eliminating risk.

In the current case, in addition to filing a plan which gives the Board very little evidence on which to rely to satisfy itself that the forecasts of costs and revenues are reasonable or at least within a range of reasonableness, Enbridge has asked for new deferral and variance accounts, one of which Enbridge has admitted is asymmetrical in favour of the utility,[72] an expanded definition of what would qualify for Z-factor treatment, annual adjustments for a significant number of variables affecting revenues, projected ROE which changes annually, WACC that changes in every year of the plan, and variance account treatment for the large "extraordinary" capital items within the plan term.

Each of these aspects of Enbridge's proposal is dealt with in more detail in the submissions that follow, but for the purposes of assessing the model at a high level, Staff submits that there is not an appropriate balance of risk and reward in the Proposed Customized IR Plan as filed.

Dr. Kaufmann articulated his concerns with respect to this point in his oral testimony at the hearing. While his comments were provided in the context of a discussion around the variance account created for relocations and mains, he did provide broader insight with which Staff agrees.

> And if you have a five-year plan, where you have forecasts built into that plan and that is the basis for your rates, then you shouldn't -- the core elements of that plan, things that are not big projects that you can't budget for or things that are locations might be due to changes in policy, external factors entirely beyond your control, the company's replacement pattern and its replacement expenditures are entirely within its control.
>
> You know, they can -- it's going to depend to some extent on past customer growth, but the extent to which they undertake those replacements is very much a management decision. And that should not

[72] In TCU 1.16 Enbridge confirmed that due to the $1.5 million threshold set for these variance accounts proposed for relocation and replacement mains for 2017 and 2018, it is not mathematically possible for Enbridge to be in a position to underspend enough to give refund money to ratepayers. As such the account would be asymmetrical and provide protection only to the Company against risks of overspend.

> be something, in my opinion, that should be Y factored or subject to a variance account.
>
> So just to step back a second, we know that incentive regulation is supposed to be a substitute for cost of service regulation, and all of these variance accounts are very much focused on cost recovery. Each one is kind of a miniature cost of service review or plan in itself.
>
> **When you layer in more and more of these things on top of an incentive plan, it tends to -- at some point, the plan becomes something other than an incentive regulation plan. And I haven't really made an issue of this before, you know, before this point, but I have become aware of that and I think that is a problem.**
>
> So I don't know if that necessarily answers your question about something they can do to protect against the forecasting issue per se. But **one thing they could do to make this plan more of a -- to move it in the direction of an incentive plan is to scale back on some of the Y factoring in variance accounts**, particularly for replacement.[73]
>
> [Emphasis added.]

Each of the aspects of the plan enumerated above tend, in Staff's submission, to shift the risk away from the utility and onto the ratepayer with no concomitant reduction in ROE level throughout the plan.

[73] Tr. Vol. 3, p. 143 (line 18) – p. 144 (line 20).

Discussion of Elements of the Plan

A. Sustainable Efficiency Incentive Mechanism (“SEIM”)

As part of its Customized IR plan proposal, Enbridge has included a mechanism to provide a cash incentive after the plan term expires to promote longer term sustainable efficiencies (and not just short-term cost cutting) that would carry over into the next plan term and perhaps beyond.

The stated goal of the SEIM is to produce incentives for management to undertake long-term sustainable efficiency initiatives. It is also to reduce any motivations for utility management to delay efficiency enhancing projects when nearing the end of the IR term.

As explained by the Company, the SEIM balances the goal of incenting the utility to find and take advantage of sustainable efficiency initiatives with measures to protect customers by ensuring that Enbridge only receives a reward where its performance merits a reward.

The SEIM reward would be available in cases where Enbridge can demonstrate that the value of the efficiency initiatives undertaken exceed the amount of the reward, and where it can demonstrate that it has maintained good service and operations levels through the IR term. The SEIM reward would not apply until after rebasing, presumably in 2019, and there would be a cap on the amount of the SEIM reward that is available.

Operationally, this is how the SEIM would work:

- Enbridge may make a one-time application for a SEIM reward in the rebasing year.
- The amount of the available reward will be a function of the difference between Enbridge’s actual and allowed ROE during the term of the plan, as follows: (1) the form of the reward will be a premium on the ROE used for rates for up to two years beyond the term of the plan (i.e. the rebasing year and the next); and (2) there would be a cap of 0.5% ROE per year on the reward.
- Conditions: (1) the net present value (NPV) of the long term benefits to ratepayers from Enbridge’s sustainable productivity initiatives undertaken during the IR term must be greater than the available award, and (2) the utility’s quality of service during the IR period has stayed at or above the current level.

Staff's Position

Staff submits that the SEIM has multiple flaws, both methodological and in its implementation and as such, staff proposes that it not be implemented in its current form. At the oral hearing Dr. Kaufmann outlined the SEIM's shortcomings in some detail.[74] Staff notes that even Enbridge acknowledged that the proposal could benefit from modifications.[75]

The first flaw is that the SEIM reward is based on a 5 year average of exceptional ROE performance during the IR period where the average ROE exceeds the Board-allowed rate. This ROE trigger was criticized by Dr. Kaufmann in that it produces an inherent incentive for the company to inflate its capital forecasts at the outset of the plan.[76] The difficulty is that inflated capital forecasts will serve to enrich actual ROE results.

Also, the SEIM should be primarily focussed on creating incentives to pursue cost efficiencies at the end of the plan term, so as to overcome the incentive for short-term cost cutting at the end of the plan term. This implies that the proposal to use an average ROE over the entire 5 year period produces an inappropriate incentive.[77] The staff expert witness Dr. Kaufmann said the SEIM should be redesigned. Dr. Kaufmann offered that the Efficiency Carryover Mechanisms (ECM) in Australia and for the water utilities in the UK , which are similar to the SEIM (but certainly not identical), could be imported into the Enbridge plan.

Board staff submits that another problem with the SEIM proposal is that there is no way of knowing if the future benefits will materialize because of the use of a long term NPV of cash flows for the calculation of the reward. The efficiencies identified are unverifiable, and this is problematic for a regulator because cash rewards should be verifiable and not based solely on company projections. A third party stakeholder verification system could be adopted to address this deficiency. However if it were adopted, staff submits that this would create a new "DSM-like" regulatory construct. It would serve to engage the interested parties in a regulatory consultative to verify the SEIM benefits. This would not necessarily be undesirable in and of itself; however, it could be costly and time-consuming. It may not be an efficient use of time and resources in staff's opinion.

Also, the proposed SEIM reward could be viewed as competing with the ESM because both are constructed on the basis of exceptional ROE performance. This is problematic

[74] Tr. Vol. 3, p. 59-65.
[75] Argument in Chief, p. 70.
[76] Tr. Vol. 3, p. 60.
[77] Tr. Vol. 3, p. 62.

in that it means that the award granted under the ESM could be taken away, at least in part, with the later SEIM reward.

Staff submits the flaws of the SEIM are of such a profound nature that it needs to be carefully re-thought. The SEIM is a complex and delicate mechanism whose objectives may compete with desirable objectives and outcomes from an IR plan. The evidence was unclear as to how exactly the Australian scheme (EBSS) would work in an Ontario setting. Not only that, but the experts disagreed as to the advisability of importing the ECM mechanism.[78]

Board staff is uncomfortable recommending a specific SEIM construct at this time without examining the issue in greater depth. It is a complex issue that needs to be well thought out to correctly induce the appropriate incentives. It requires a considered design and construction.

Staff would not suggest importing the models from Australia or the UK at this time until further research can be done to validate their effectiveness in a local setting.

However, staff commends Enbridge for making an attempt to construct a solution to the tricky problem of incenting the generation of efficiencies so as to be long term and sustainable after the IR plan term has expired.

[78] Tr. Vol. 3, p. 149.

B. Z Factor

Enbridge has proposed the following new language to govern the Z factor during the term of its IR plan application.

> A cost increase or decreases will be treated as a Z factor if it meets all four of the following criteria:
>
> (i) Causation: The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine cause.
>
> (ii) Materiality: The cost at issue must be an increase or decrease from amounts included within the Allowed Revenue amounts upon which rates were derived. The cost increase or decrease must meet a materiality threshold, in that its effect on the gas utility's revenue requirement in a fiscal year must be equal to or greater than $1.5 million.
>
> (iii) Management Control: The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management is unable to prevent by the exercise of due diligence.
>
> (iv) Prudence: The cost subject to an increase or decrease must have been prudently incurred.[79]

This language is materially different in some ways to that which was in effect during the last IR plan for Enbridge during 2008 to 2012. Enbridge is proposing to modify it because, as summarized by Company witness Mr. Ryckman at the hearing:

> I think with the original Z factor language, the main problem we had was that there doesn't appear to be anything that would qualify, which basically means that there is no Z factor.[80]

Enbridge applied for two Z factors previously under the existing ("original") language and was denied recovery by the Board on both counts.

Staff's Position

As a first point, Board staff notes that the proposed language has not been accepted in any other Board proceeding, electricity or gas.

[79] Ex. A2, Tab 4, Sch. 1, para 3.
[80] Tr. Vol. 2, p. 148.

Board staff however is not opposed to reviewing the language with a view to improving the mechanism. Board staff would advocate several modifications to the proposal to change the language.

Board staff's expert Dr. Kaufmann, reviewed the Company's proposal. He expressed a concern about criteria (i) above, "causation", and explained that the linkage to a "cause" rather than an "event", which was the language in the first generation IR plan, would be harder to pin down, would expand the scope of Z factors, and would thus lead to potentially expensive regulatory investigations into Z factor claims. Dr. Kaufmann said:

> In our opinion, the 2008-2012 Z factor language that an "event must be causally related to an increase/decrease in cost" is far more clear than Enbridge's proposal that "the cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine cause." "Events" are discrete, concrete and readily identifiable. "Causes" are often subtle, complex and difficult to identify. Changing the impetus for Z-factor filings from "events" to "unexpected, non-routine causes" would shift the focus of Z investigations into broader and murkier territory. This, in turn, is likely to lead to more frequent, contentious and costly Z factor proceedings.[81]

Board staff agrees with this concern submits that the Board should reject the Company's proposal to link Z factors to "causes": They should instead be linked to "events".

Staff also notes that Dr. Kaufmann had a concern about the proposed language in criteria (ii) of the Enbridge list of criteria above covering materiality. PEG's view is that the language would be clearer with the following revisions:

> ii. the cost must be beyond what Company management could reasonably control or prevent through the exercise of due diligence. [82]

Board staff agrees with Dr. Kaufmann and would suggest that this language be adopted.

On the materiality issue, Board staff notes that in the recent Union Gas settlement agreement, which was approved by the Board, the materiality threshold for a Z factor was set at $4 million.[83] Enbridge has proposed $1.5 million which was in place during the previous 2008 to 2012 IR term. Given that Enbridge's revenue requirement is higher than Union Gas, its relatively low risk, and its substantial and robust revenues,

[81] Ex. L, Tab 1, Sch. 2, p. 24.
[82] Ibid.
[83] Ex. K1.4, p. 23.

staff’s view is that unexpected events under $4 million should be managed by Enbridge within its revenue allowance. This Z factor threshold is well under 1% of Enbridge’s annual revenue requirement. Staff therefore recommends increasing the materiality threshold and moving Enbridge to a new Z factor threshold level of $4 million.

C. Floating ROE

Enbridge has outlined its proposed for the treatment of Cost of Capital during the plan term.[84] The capital structure is proposed to remain at the current levels, and the proportional mix of long term debt, short term debt, and preferred shares will vary by a small amount each year of the plan according to the pacing of investments and cash flow requirements. Enbridge proposes to hold equity levels at a constant 36% of the capital structure throughout the plan, which is the Board-approved percentage established in the 2013 COS proceeding EB-2011-0354.

An unusual feature of the plan, though, is the proposal for the level of the Return on Equity (ROE). The proposal is that ROE will float at a forecast level, to be set now, for each year of the plan. This forecast would not be trued-up to actual nor updated through the annual update process. Based on the Company's projections of ROE provided in its return on equity evidence[85] this represents an increasing ROE relative to the base amount of 8.93% for 2013 approved by the Board. For 2014, 2015, 2016, 2017 and 2018, the ROE is forecasted at 9.27%, 9.72%, 10.12%, 10.17% and 10.27% respectively. The increasing ROE, when applied to the increasing rate base levels throughout the plan, produces significant increasing revenues in the customized model relative to the 2013 base year. The Company's witnesses stated the revenue requirement increases associated with the ROE increase alone is $130 million.[86]

Staff's Position

Board staff's view is that the proposal to have a floating ROE throughout the plan term should be rejected.

First, the ROE is a forecast amount pinned to interest rates established at a time of June 2013 (the date of the application). The interest rate projections upon which ROE is based are notoriously inaccurate – especially when considering the proposal extends as far as 5 years to 2018. Even 2 years forward is an inappropriately long forecast to be considered accurate. This fact is evidenced when one compares the rate forecasts provided in support of the original evidence (June 2013) to a requested update at day 10 of the oral hearing (March 2014).[87] A comparison of the two exhibits shows

[84] A2/5/1
[85] E2/1/1
[86] Tr2 page 38. Also Tr10 page 4.
[87] IRR Energy Probe 20 Issue B17 (I.B17.EnbridgeI.EP.20) This data is compared with data provided at J10.4.

differentials in rates relative to the basis underpinning the June 2013 application. This is not surprising given that the macro factors that influence interest rates can change over a relatively short period of time.

Second, Enbridge claims that it's allowed revenue forecasts do not include inflation and therefore the floating ROE is justified. This is incorrect as the evidence shows inflation is in fact included in the forecasts. For example in the O&M evidence the Company says that "an inflation rate of approximately 2% was applied for 2014 to 2016 to all O&M departments." [88]

Third, the ratepayer impacts are very material and this fact needs to be considered when using longer range forecasts of this nature.

Fourth, Board staff is not aware of any precedent for a floating ROE treatment in an IR Plan in Ontario or elsewhere.
Further, no previous IR plan at Enbridge has had a floating ROE. Incentive Regulation plans typically freeze ROE at the "base year" level. In this case the 2013 ROE should be frozen for the plan term (i.e. ROE 8.93%).

Finally, Board staff observes that the Union Gas 2014-2018 IR settlement agreement has a frozen ROE at 8.93% for the term of the plan. Noteworthy also, is that the settlement established the ROE for the purposes of sharing earnings at the same (i.e. the Enbridge 2013 approved) level of 8.93%.[89] Board staff suggests that the Board adopt this same approach for earnings sharing at Enbridge, to avoid any confusion over what the level of ROE is for that purpose.

[88] D1/3/1 para 19a.
[89] K1.4 page 26.

D. Forecasts

(a) Capital Forecast

Enbridge has proposed a capital expenditure forecast for each of the next 5 years. The Company has held 2017 and 2018 "flat" at 2016 levels due to its stated inability to provide an accurate forecast because of the uncertainty associated with capital budgeting for years this far into the future. There are two leave to construct projects included in the capital plan and both have received Board approval. There is also a major IT replacement project included at $70.1 million (the Work and Asset Management System "WAMS").

The capital budget for 2014 to 2018 is projected to be significantly higher than what has been historically included in rates. According to the Company there are 2 primary reasons for this.

The first reason relates to technical regulations that require an assessment of potential failures of operating assets. The TSSA has a requirement for a mitigation plan to be in place before any such failures occur.[90]

The second reason is the need for the 3 major projects. These include the GTA Project, the Work and Asset Management Project and the Ottawa Reinforcement Project.

The Company also characterized its capital budget this way:

> The capital budget for the term of the Customized IR plan is the combination of three elements: (i) the GTA Reinforcement Project, which has been the subject of a leave to construct approval; (ii) the needs of the Company to sustain operations, including customer additions, replacements and relocations; and (iii) the integrity management programs which the Company is required to undertake.[91]

The Company stated that it undertook a "rigorous" internal review process with the goal of arriving at what it termed "the lowest prudent capital plan for the next regulatory term". The capital plan included in the application is claimed to "include significant risks" and is purported to have "embedded productivity improvements".

The amounts for each major category are shown in the following table.

[90] See Ontario pipeline regulation clause 3.2 of CSA Z662-11 included at J5.11 and which also includes a discussion of this requirement and its impact.
[91] Argument in Chief, p. 21.

Capital Budget

$millions

	2013 (actual)	2014	2015	2016	2017	2018
Core Capital	441.6	480.1	472.3	441.9	441.9	441.9
WAMS		36.3	25.7	8.1		
LTC - Ottawa	61.9	5.1				
LTC - GTA	14.3	197.1	359.7			
Total Capital	517.8	682.3	832.0	450.0	441.9	441.9

On the question of Asset Planning, it appears that Enbridge is relatively new to the practice of Asset Management Planning, having only gone through a couple of iterations according to the company witness Mr. Sanders.[92] Mr. Sanders also indicated that there is more to be done in terms of bringing the operations and maintenance costs into the equation (of asset planning).[93]

In response to a question from panel member Dr. Elsayed about asset management, company witness Mr. Sanders offered some insight into the how the Company views asset planning and that there is more work to be done. Specifically Mr. Sanders indicated that the asset planning process does not include operating and maintenance costs and therefore does not provide a full life cycle view.[94]

[92] Tr. Vol. 5, p. 165.
[93] Ibid.
[94] Tr. Vol. 5, p. 162.

Staff's Position

After reviewing the evidence, staff has difficulties in either endorsing or rejecting the forecasts provided. As previously submitted, there is no objective evidence to rely upon, other than the Company's assurances of reasonableness in their forecasts. Also, the evidence shows that the budgeting process and the Asset Management Planning process are carried out as separate processes and there appears to be no direct linkage between them. In practice, the capital budget should "fall out" of the higher level strategic asset plan. Staff acknowledges that the Company is new to the world of asset planning, but there should be some evidence of a clear linkage between the two activities of asset planning and budgeting – they should not be separate processes with no accountability to one another, which appears to be the case here.

As part of the remedy to address these shortcomings, Board staff proposes that the Board adopt the stretch factor approach discussed previously.

Enbridge should be required to report annually on its capital progression (i.e., actual vs. the forecast that was built into the IR plan at the outset and that forms part of the Board-approved revenue requirement).

Staff suggests that Enbridge should be required to report on its performance outcomes related to its capital program. For example Enbridge's increased expenditures on system integrity may result in outcomes such as a reduction in leaks, ruptures, losses and/or maintenance expenditures. EGD should specifically identify the expected outcomes associated with its capital plan and report on the achievement of the outcomes so that the Board can monitor the capital plan in the context of outcomes.

A further example is that Enbridge has identified the outcomes for the GTA project that include improvement of the supply chain diversity, reduction of upstream supply risks and the reduction of gas supply costs over the period 2015 to 2025. The achievement of these outcomes could also be tracked and monitored (i.e., the initiatives to reduce gas supply costs could be recorded and the associated results could be tracked and monitored).

The full suite of reports (traditionally required as part of the earnings sharing and deferral account disposition hearing) should also be continued (this was not explicitly mentioned in the application). The list of reports which staff submits should be filed is available within the Union settlement agreement filed in this proceeding. [95]

[95] Ex. K1.4, p. 27.

(b) O&M Forecast

Enbridge's O&M expense forecast is as follows.

$millions

	2013 Board-approved	2014	2015	2016
Customer Care / CIS	89.4	92.6	96.5	100.4
DSM	31.6	32.2	32.8	33.5
Pensions and OPEB	42.8	37.2	33.8	30.9
RCAM	32.1	35.3	34.0	33.8
Other O&M	219.2	228.0	231.5	241.0
Total O&M	415.1	425.3	428.5	439.5

Staff submits that only the "Other O&M" line above represents what is truly at issue in this proceeding as far as O&M is concerned. This is because the other cost categories have been previously addressed by the Board in other proceedings (for example the Customer Care / CIS proceeding dealt with this operating cost category in proceeding EB-2011-0226). The evidence is that inflation (at about 2% per year) has been built into the forecast of Other O&M. There is no X-factor (notionally, X is deemed to be zero per the recommendation of company expert Concentric Energy Advisers). However the Company says that the budget includes $172.5 million worth of productivity that is either baked into the numbers already or needs to be found.[96]

Other O&M includes Human Resources related costs (net of capitalization) including salaries and wages, employee benefits, short term incentive program, employee training and development, materials and supplies, outside services, consulting, repairs and maintenance, fleet, rents and leases, telecommunications, travel and other business expenses, memberships, provision for uncollectables, claims, damages, legal fees, audit fees, A&G capitalization, and other.

[96] J1.6.

Staff's Position

Staff notes that a very large portion of the Other O&M costs consist of expenses that are employee-related – salaries and wages, benefits, Short Term Incentive Program (STIP), and training. Board staff accepts that the Company has put some measures in place in the budget to "challenge" management in achieving the budget target.

Overall staff does not recommend a specific disallowance of any particular element of the O&M budget. The level of inflation built into the plan is not unreasonable to staff. There may be over-forecasting as this is an overarching concern about the "building blocks" form of incentive regulation as expressed in the expert's assessment report authored by Dr. Kaufmann.[97]

Staff would see the stretch factor proposed by Staff as part of its overall recommendations as taking into account of any over-forecasting that may be present in the Other O&M budget while at the same time, providing an incentive to management to perform more cost-effectively during the plan term.

Staff would not have a concern if the Board were to accept Enbridge's O&M budget (including the $172.5 million reduction) as filed. However the Board should require Enbridge to identify programs created for the specific purpose of achieving productivity and efficiency gains and report on those programs on an annual basis. Staff notes that this reporting mechanism is already included as a feature of the application and is likely sufficient as proposed.

With respect to the forecast of regulatory costs, the evidence shows that the expense is forecasted at $8 million in 2014 and then $6 million in 2015 and beyond.[98] Staff questions whether these amounts are excessive given that the level of regulatory activity should be reduced during the IR term. However, this is an unknown. In staff's view, the Board could consider reducing these forecasted amounts now. Board staff would see a 15% to 20% reduction as appropriate and that no more than $6 million should be placed in the budget to account for regulatory costs in any one year.

(c) Productivity

The Company's evidence throughout the proceeding and in its Argument in Chief is that its O&M cost forecasts have embedded productivity built-in throughout the five years.

[97] L1-2. See for example the discussion at pages 14 to 19 of the assessment report.
[98] Ex. D1, Tab 8, Sch. 1, p. 18.

Enbridge has calculated the amount of O&M productivity at $172.5 million.[99] Enbridge claims that the embedding of this amount will present a significant challenge for it to meet the budgets at these levels.

The Company's evidence is that there is also productivity embedded in its capital budgets. Enbridge has provided the total amount of capital budget productivity (termed "embedded savings") at $162.6 million.[100]

Board staff observes that the figures and explanations provided for the embedding of productivity outlined in Undertaking J1.6 go to some length to explain all of Enbridge's cost reduction commitments which include reductions to its originally reviewed budgets in the O&M and capital areas. Enbridge has termed these budget reductions collectively as "cost commitments". Examples of the cost commitments in the O&M area include holding merit and employee benefits increases to lower than expected amounts, and holding FTE's flat through the IR term.

In the capital budget areas, examples of the cost commitments include holding capital costs for customer attachments to pre-2012 levels and keeping departmental labour costs flat over the IR term.

The Company characterized the variable costs as follows:

> The Company has identified $164 million in uncertain or "variable" capital costs over the period 2014-2016 that have not been included in the capital budget. This represents 12% of the Company's core capital budget that Enbridge expects to have to cover to some degree over the forecast period. These are just the items that Enbridge knows about at this time. There will be other capital challenges that arise through the normal course of business that have not been anticipated, which will have to be managed through the five-year IR term.[101]

The Company has suggested that given the existence of this built-in productivity, it has overcome concerns that its budget forecasts are lacking in productivity, and hence the resulting implication being that the Board should find no need to either impose cost disallowances or impose any "X" type of factor on these budget forecasts.

The issue is whether the Company's claims to embedded productivity provide sufficient evidence, and hence comfort, to the Board that its methods and processes produce budgets that are both meaningfully and realistically, reasonable.

[99] J1.6 page 2 of 7.
[100] J1.6 p. 2.
[101] J1.6 p. 5.

Staff's Position

In staff's view, Enbridge's efforts do not represent true productivity. What the Company has provided are merely budget presentations that may, or may not, be as low as the utility could go while still meeting the needs of its business. Board staff submits that external parties have no way of verifying whether Enbridge could have presented a lower budget and one that at the same time would be realistically achievable. In the hearing the parties referred to this as information asymmetry.

Enbridge provided no list of corporate programs or other company-wide initiatives that will be implemented to achieve measurable and verifiable productivity and efficiency gains. Board staff submits that there needs to be a well-considered strategy and implementation program to provide credibility to the statements made around "cost commitments". Given the lack of any organized corporate programs in place at the utility that will be able to achieve $172.5 million in productivity, Board staff submits that the efforts at productivity may not translate to true sustainability. The Company simply has not gone far enough to make a persuasive case for sustainable productivity improvements.

Staff's view is that the budgets are not a "stretch" in the sense of being over and above the bottom-line budget. Enbridge has described its forecasts as being inclusive of productivity savings but staff believes they are simply forecasts that could go further to achieving customer benefits more in line with what incentive ratemaking is intended to produce.

Also when viewed in the context of the entire amounts sought for recovery, the "embedded productivity" amounts do not appear to be large. The total revenue amounts requested are some $13.8 billion. The capital requested is $2.8 billion and the O&M is $2.2 billion. The amounts offered for capital and O&M productivity are fairly modest in percentage terms when compared to the total revenues. Board staff calculates the total amount of "embedded savings" to be about 2.4% of total revenues.[102]

[102] J1.6 p. 2.

E. Regulatory Cost Allocation Methodology ("RCAM")

Enbridge has included amounts for the RCAM for each year of the 5 year plan. The RCAM is the method by which corporate costs from Enbridge Inc. are allocated to the gas distributor for rate regulation purposes. The amounts show increases relative to the actuals observed in the previous IR term 2008 to 2012. The amounts are in the $32 million to $36 million range. Previously it had been in the $19 million to $31 million range during the last IR term.[103] However staff notes that there was a large step up in 2012 relative to 2011 (from $26.6 million to $31.6 million), apparently in light of MNP's recommendations.[104]

The RCAM intervenor consultative has not been active for some time and in fact the Company witnesses confirmed that 2012 was the last time the RCAM amounts were subject to a consultative review.[105]

In late 2013, the Board accepted an implicit RCAM figure of $32.1 million that was included within an expense envelop as part of the comprehensive settlement of the issues in the 2013 COS proceeding, EB-2011-0354.

Staff's Position

Board staff does not view the implicit amount from 2013 as being indicative of an official Board approval and would suggest the Board take a similar stance. It was part of a larger O&M expense envelope within a comprehensive settlement.

Staff is concerned with the increasing RCAM amounts generally and the fact that the intervenor consultative has not met in some time. It is unclear to staff why they have not met.

Another concern is that the forecasted RCAM amounts in the IR plan are clearly preliminary and, based on the evidence; appear to be unverified (although Enbridge claims to have followed the model's methodology). The figures should be subject to a thorough consultative review before they can be placed confidently into the new IR plan.

Board staff submits that the Board may consider freezing the amount at the 2013 implied level of $32.1 million. Alternatively the Board could take a simple average of the

[103] Ex. I.B17.EnbridgeI.STAFF.50.
[104] Ex. D1, Tab 4, Sch. 1, Attachment 1.
[105] Tr. Vol. 7, p. 89.

previous 5 years IR plan numbers (2008 to 2012) and use that as a reasonable proxy for RCAM (this would be roughly $24.6 million.[106]

[106] Ex. B17.Staff 50.

F. Deferral and Variance Accounts

Enbridge has proposed 28 deferral and variance accounts covering its 5 year IR plan term. Twenty of the accounts are continuations of existing accounts carried forward from the 2013 rate case and 8 accounts are new. The new accounts are: Customer Care Services Procurement Deferral Account (CCSPDA), Greenhouse Gas Emissions Impact Deferral Account (GGEIDA), Constant Dollar Net Salvage Adjustment Deferral Account (CDNSADA), Unabsorbed Demand Cost Deferral Account (UDCDA), Greater Toronto Area Project Variance Account (GTAPVA), Relocations Mains Variance Account (RLMVA), Replacement Mains Variance Account (RPMVA) and Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account (GTAITCRRDA).

Staff's Position

Staff has reviewed the existing accounts that are proposed to be carried forward. Staff notes that the Post-Retirement True-up Variance Account (PTUVA) was not explored in detail in the context of the current case. That account was created as part of the Settlement Agreement approved by the Board in the 2013 cost-of-service rebasing case. Staff notes the Settlement Agreement states:

> The parties agree that this approach will continue until the earlier of a) a decision by the Board to implement a policy respecting the Pensions Issue that is applicable to Enbridge during the term of its upcoming IR plan, and b) the next rebasing application for Enbridge. [107]

Staff submits that to the extent that this account is ongoing during the term of Enbridge's proposed plan, it remains subject to the conditions as stated in the Settlement Agreement.

Staff's view is that some of the new accounts serve no purpose other than to mitigate risk for the utility. Generally, the utility has not demonstrated that this additional risk mitigation is justified. The ROE is set at a level that includes a risk premium that is designed to compensate Enbridge for this type of risk. Staff believes that Enbridge needs to shoulder more of its own risk rather than offloading it to ratepayers.

Staff recommends rejecting the Relocations Mains Variance Account (RLMVA) and the Replacement Mains Variance Account (RPMVA) proposed for 2017 and 2018. These are capital costs accounts and it is not typical Board practice that categories of capital

[107] EB-2011-0354, Decision On Revised Settlement Agreement and Procedural Order No. 6, November 2, 2012, Appendix "A", Settlement Agreement dated October 26, 2012, page 20.

costs are subject to regulatory variance treatment. There is no demonstrable need for these accounts other than the utility's clear preference to mitigate risk. Staff submits that Enbridge should manage within its capital budget envelope. On this point, the evidence is clear that Enbridge's capital budgets have inherent flexibility and this is evidenced by the "variable" capital put forward by the witnesses throughout the proceeding. Staff would expect that any capital expenditures for new will be brought forward, appropriately depreciated, for inclusion in the next rate base in 2019. The prudence will be tested at that time.

Staff sees some merit in the Greater Toronto Area Project Variance Account (GTAPVA) due to the scale of the GTA project and the uncertain timing of the spend which may very well be outside of management's control. This was confirmed by Company witness Mr. Culbert in an exchange with vice-chair Chaplin.[108] However, staff is concerned that this is an open-ended account and therefore provides no incentive for Enbridge to manage project costs. Staff would advocate that it should be capped – possibly at a 10% overage level (or about $68 million to $70 million rounded). This would mean that any overage above the capped amount would not be available for recovery. In this way, ratepayers are afforded some protection and Enbridge will be incented to limit over spending (at least by any amounts over the cap). Alternatively, the Board may wish to emphasize that any excess costs over and above the forecast will be examined in Enbridge next rates application after the completion of the project.

Staff will also recommend rejecting any continuation of the Ontario Hearing Costs Variance Account (OHCVA) which is an account to track regulatory costs that serves to keep Enbridge (and ratepayers) whole on regulatory expenses for a given year. No other OEB-regulated utilities have such an account[109]

The Company has proposed a change to the Transactional Services Deferral Account for the plan term. Enbridge proposes to keep the forecast of $12 million in place, but eliminate the shareholder portion "cap" of $4 million. From the pre-filed evidence, the proposal is as follows:

> While the Company plans to continue to include a forecast of $12.0 million in Transactional Services revenue as an offset to rates, the Company is proposing a change to the derivation of amounts in the TSDA. Given the recent NEB changes within TCPL tolls and unknowns within the future prices and potential related impacts, Enbridge is proposing an update to the TSDA methodology and scope. In the event that the ratepayer share of 2014-2018 TS net revenue exceeds $12.0 million, then such amounts over

[108] Tr. Vol. 11, pp. 70, 71.
[109] Tr. Vol. 11, p. 30.

> $12.0 million will be credited to the TSDA. In the event that the ratepayer share of 2014 TS net revenue is less than $12.0 million, then Enbridge will be credited with the difference between the actual ratepayer share of 2014-2018 TS net revenue and $12.0 million. This is a change from the 2013 TSDA. Currently the maximum credit to Enbridge is $4.0 million. The Company is proposing that there be no cap on the amount being credited to Enbridge should the ratepayer share of TS net revenue be less than $12.0 million.[110]

Board staff submits that the amount included in rates should be increased from $12 million to $24 million, based on the performance of Transactional Services (TS) in the last two years 2012 and 2013. Board staff sees no reason that these levels of TS activity should not continue. In 2012 TS produced $26.077 million and in 2013 TS produced $24.065 million. Both of these figures are from the recently filed QRAM application under file number EB-2014-0039.[111] The 2013 amount was confirmed by Company witness Mr. Culbert to be a 90/10 sharing figure, representing 90% of the TS revenues.[112]

Board staff further submits that the revenue sharing treatment continue (from the current 2013 arrangement) throughout the plan term, so that the Company's share increases commensurately with the amount in rates. The amount in rates is doubling, therefore the "cap" amount representing the maximum available to the shareholder would also double, from $4 million to $8 million.

[110] Ex. D1, Tab 8, Sch. 1, p. 8.
[111] EB-2014-0039 Ex. Q2-2, Tab 2, Sch. 2, p. 2.
[112] Tr. Vol. 11, p. 42.

G. Earnings Sharing Mechanism ("ESM")

Enbridge has proposed an ESM for the Customized IR term to facilitate the sharing of earnings with ratepayers above a set threshold, or benchmark. The manner in which this is determined is proposed as calculating the actual weather-normalized ROE earned in a given year, and comparing that to the ROE level determined by the application of the Board's 2009 ROE Formula ("Allowed ROE"). Where the actual ROE is more than 100 basis points above Allowed ROE, then the associated over-earnings will be shared equally with ratepayers. Enbridge will not share the first 100 basis points of over-earnings. The proposed ESM is asymmetrical, such that ratepayers will not be responsible for sharing (i.e. "paying for") any level of under-earnings.

Enbridge's pre-filed evidence describes how the ESM operates, as follows:

> In terms of the functional workings of the ESM, Enbridge proposes to continue to use a methodology substantially similar to that which was established in the Settlement Agreement for Enbridge's 1st Generation IR plan. Specifically, the ESM would function as follows: (i) If in any calendar year, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated annually by the application of the Board's ROE Formula in any year of the IR Plan, then the resultant amount shall be shared equally (i.e., 50/50) between Enbridge and its ratepayers; (ii) For the purpose of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings; (iii) All revenues that would otherwise be included in revenue in a cost of service application shall be included in revenues in the calculation of the earnings calculation and only those expenses (whether operating or capital) that would be otherwise allowable as deductions from earnings in a cost of service application, shall be included in the earnings calculation.[113]

Staff's Position

Board staff does not oppose the ESM proposal as the mechanism is substantially the same as that which was in effect during the previous IR term which, in staff's view, worked well. However staff wishes to make a clarification on the proposal. The ROE used as the benchmark for the calculation of earnings sharing in any given year should be the Board-approved ROE of 8.93% established in the 2013 COS re-basing. In other

[113] A2/7/1 page 2

words, the benchmark ROE for use in the sharing calculation should not “float” annually. Rather, it should be set at the outset.

It is not clear from Enbridge’s proposal how, precisely, the annual benchmark would be established. Board staff’s clarification is consistent with the wording used in the recent Union Gas settlement agreement[114] and is consistent with how the ESM was applied in during the previous IRM term.

[114] K1.4 page 26.

Other Issues

A. Site Restoration Cost Proposal ("SRC")

In its Argument- in-Chief ("AIC") Enbridge restated its proposal concerning SRC which it encourages the Board to approve. Specifically, Enbridge recommends the adoption of the Constant Dollar Net Salvage ("CDNS") approach for SRC, also referred to as net negative salvage.[115]

> Based on the application of the CDNS methodology, the reserve amount required by Enbridge for SRC is smaller than currently has been collected and lower depreciation rates are required on a going-forward basis. Enbridge proposes to return $259.8 million to customers by way of a rate rider. The rate rider amounts do not directly affect rates and are not included in Allowed Revenues, but would have bill impacts in the form of lower customer bills than would the case in the absence of the SRC proposal.
>
> The return of $259.8 million to customers indirectly affects rates and Allowed Revenues in two ways. First, as amounts are refunded to customers, accumulated depreciation is reduced, net rate base in turn increases and Enbridge's cost of capital is applied to a higher rate base. Second, the return of amounts to customers gives rise to a tax deduction which lowers taxes payable. As well, a third impact on rates and Allowed Revenues occurs by reason of lower depreciation rates going forward. Taken all together, the three effects of the SRC proposal on Allowed Revenues result in a cumulative reduction of $241.4 million over the five year term of the Customized IR plan.
>
> While it may be that some questions during cross-examination implied a negative view of the SRC proposal, Enbridge submits that the Board should see the proposal as a positive aspect of Enbridge's application. The SRC proposal has both a rate mitigation and a bill mitigation effect; these effects are timely and opportune in that, as stated above, Enbridge is able to meet important capital spending needs and at the same time implement a proposal that moderates rate and bill impacts.[116]

[115] Tr. Vol. 9. p.70, 6-9.
[116] Argument in Chief, pp. 59-60.

(a) Selection of discount rate/Asset Retirement Obligations ("ARO")

The Board has approved the recovery of net negative salvage as a component of depreciation since at least 1959.[117] Due to changes in accounting standards in 2009, Enbridge had to calculate the impact of rate regulation on SRC. At the end of 2009 the SRC disclosed in the audited financial statements was $692 million. By the end of 2013 the SRC liability had grown to $903.9 million.[118] The balance of the liability changes over time due to recoveries through depreciation and actual amounts spent for asset retirements.[119]

In answer to interrogatories, Enbridge provided evidence that approximately $3 billion would be required for site restoration costs related to the balance sheet value of assets at the end of 2010 of $5.9 billion.[120] In cross-examination Board staff suggested that this implies a rule of thumb of about 50%.[121] Applying this rule of thumb to the asset values projected to the end of 2018 of over $10 billion, Board staff suggested that Enbridge would require approximately $5 billion of SRC to be recovered over the lives of the assets.

Mr. Kennedy of Gannet Fleming suggested that there may not be a linear relationship to arrive at this conclusion to project 2018 from the end of 2010. However, Mr. Kennedy stated that the likely amount would be "north of $3 billion".

> MR. KENNEDY: I'm going to answer yes to the first half of your question. I wouldn't suggest that that 50 percent number remains constant or linear through periods of large capital additions and retirements, as I had the privilege of chatting with Mr. Shepherd this morning. It depends on the retirements that go along with that, on the distribution of such retirements and the type of assets.[122]
>
> I agree with the assumption that the SRC fund is going to need to increase; I'm not sure it's quite as linear as continuing at a 50 percent rate.
>
> MS. SEBALJ: But on a $10 billion -- on $10 billion of assets, it is going to be a significant amount of money, and 50 percent -- you are telling me 50 percent is not a rule of thumb, but at the end of the day it is going to likely be in excess of $5 billion in monies associated with these assets?

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[117] Ex. I.E40.EnbridgeI.Staff.84.
[118] Ex. I.E40.EnbridgeI.Staff.77, Attachment 1.
[119] Ex. I.E40.EnbridgeI.Staff.77, Attachment 1 . J9.2.
[120] Ex. I.E40.EnbridgeI.Staff.94.
[121] Tr. Vol. 9, pp.117 (line 27) - p. 118 (line 20).
[122] Tr. Vol. 9, pp.118, lines 21-28.

> MR. KENNEDY: I would think that is maybe a reasonable rule of thumb. It is going to be definitely north of the 3 billion. Whether it is 5 or not is -- it's probably pretty close.[123]

Board staff submits that since Enbridge has already collected $900 million, and recognized a liability, the remaining amount required would be higher than $2 billion but less than $5 billion.

Following the proposal of the refund and adopting CDNS, Enbridge projected the SRC balance at the end of 2018 based on the evidence filed in this case. That forecast amount at the end of the time period is $815.1 million.[124] In response to the undertaking, the projected amount at the end of 2018 is $398.2 million.[125] The only difference in assumptions is the discount rate to calculate the present value.

Using a discount rate of 2.38%, Gannett Fleming calculated in its net salvage study a theoretical over-collection from ratepayers, or the refund amount, of $259.8 million as at the end of 2010. The explanation of the difference between $292.8 million and $259.8 million can be found in exhibit K9.1.

> Gannett Fleming has calculated that if the CDNS method had been used since inception for all accounts, the accumulated depreciation related to net salvage would have been $292.8 less than the current amount.

Gannett Fleming chose the discount rate of 2.38% in the CDNS study by assuming a methodology used in Canada rather than that would be used to determine AROs in the USA. However, Enbridge has disclosed that it cannot estimate AROs.

> For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.[126]

> MR. CULBERT: No. Enbridge Gas Distribution does not record asset retirement obligations in a fashion that other entities might, who have met the criteria of doing so. We do not record asset retirement obligations.[127]

> MR. CULBERT: I would have to assume that there has been, between our legal department and our auditors who have signed off on our financials,

[123] Tr. Vol. 9, pp.119, lines 1-13.
[124] Ex. I.E40.EnbridgeI.Staff.77, Attachment 1.
[125] J9.2, p.2.
[126] J1.1, 2013 audited financial statements, Note 2, p. 15.
[127] Tr. Vol. 9, p.35, lines 12-15.

> that at this time we do not have such a legal obligation. I would have to check with them, though, because I have not been involved in that.[128]
>
> MR. KENNEDY:
> So what you will see is utilities in the States predominantly will say something along the lines -- and this is layman's version of a whole bunch of accounting and legalese -- that we know there is multiple life cycles -- jeez, I did it again -- there's multiple life cycles that occur within utility plan, and because that period gets into the many, many hundreds of years, you effectively come to a zero calculation, if in fact you can make it.
>
> So they've said if we have 50- and 60-year asset lives, and we assume five or ten life cycles, well, you are getting centuries, in terms of before you are finding abandonment on a site.[129]
>
> MR. KENNEDY: It is. It is not a –- it is an estimate of the cost of retirement. In my view, the use of a discount rate, well, it becomes a challenge. What's the right discount rate?
>
> The normal practice in this country has been to use the Canada long-term double-A rate, as I have in my calculations, not the -- for these type of normalization calculations.
>
> The FASB, for whatever reason, has asked for a credit-adjusted rate. I haven't done that. I, quite frankly, didn't think that the use of that ARO-style calculation
> number, the requirements of it, would make -- quite frankly, I viewed that the use of the -- as we have in most of my calculations throughout this country, when I've done this type of normalization, was to use the Canada double-A long-term rate.
>
> I thought that was fair here as well.
>
> The goal is to be fair and try to accurately reflect the correct current value of that future liability.[130]

Since Enbridge strongly supported its position that it does not recognize AROs, it appears to staff that selecting a discount rate based on ARO methodologies may not be the most appropriate approach.

[128] Tr. Vol. 9, p. 41, lines 19-24.
[129] Tr. Vol. 9, p. 45, lines 17-28.
[130] Tr. Vol. 9, p. 54 (line 18) - p. 55 (line8).

Enbridge values its projected pension benefit obligations (or long-term liability) each year for accounting purposes. The following table shows the discount rates disclosed in Enbridge's audited financial statements.[131] Enbridge and its actuaries selected these discount rates based on AA bond yields at the end of each year.

	2013	2012	2011	2010
Pensions & OPEBs	5.0%	4.3%	4.5%	5.7%

Board staff asked why the discount rate used in CDNS calculations was not the same rate that Enbridge used to determine the pension obligations at the end of 2010.[132]

> MR. KENNEDY: Well, as I explained this morning, we were basing our calculations on December 31st, 2010, and I followed the -- really the guidance of the international financial standard that suggests that for this style calculation, had we been doing an ARO calculation, we would have used the 2.38 as at December 31st, 2010.[133]
>
> So really, the timing may be more of an issue where my number is different than may have been used in the pension plan. Quite frankly, when did I my calculations I don't know, and I'll admit to not thinking about trying to normalize that discount rate with other net present value calculations the company had made in other areas.[134]

Intervenors and Board staff asked Enbridge to recalculate the SRC numbers with a higher discount rate. Using a discount rate of 4.95%, Gannett Fleming's calculations show a theoretical refund amount of $503.1 million which is the sum of the refund in J9.2 for the period 2014-2018. The ending balance shown in J9.2 is $398.2 million. At the end of 2010, Enbridge recognized the SRC liability of $753 in its financial statements.[135] If the proposed refund of $259.8 is deducted from $753, the net result is a remaining SRC liability of $493.2 million at the end of 2010 which was the level recommended by Gannett Fleming.[136]

Board staff submits that the selection of the appropriate discount rate to use in CDNS is dependent on many variables and it would have been possible for Gannett Fleming to

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[131] J1.1, Note19, p. 32. 2010 discount rate from EB-2013-0046 Ex. D, Tab 1, Sch. 1, Note 18, page 28 (32).
[132] Tr. Vol. 9, p.125 (line 16) - p.126 (line 1).
[133] Tr. Vol. 9, p.126, lines 2-7.
[134] Tr. Vol. 9, p.126, lines 23-28.
[135] Tr. Vol. 9, p.73, lines 18-22.
[136] Tr. Vol. 9, p.74, lines 5-7.

select a higher rate than the 2.38% used both in 2009 and at the end of 2010. Board staff submits that had a higher discount rate been used at the outset the revised calculations would not produce a theoretical over-collection in the net present value calculations now.

(b) Fixed Asset Useful Lives and Need for SRC

The useful lives of fixed assets have been raised at different times in the proceeding both in written evidence and in oral testimony. Mr. Sanders made comments about Enbridge's asset management plan.

> MR. SANDERS: And I am looking at those numbers too, Mr. Shepherd, and if I take, again, 36,000 kilometres of pipe and replacing it at less that 100 kilometres per year, it sure takes me beyond the 40-, 50-, 60-year life of that pipe. That is the challenge that we have.
>
> And this is, as I said earlier, one of the difficulties I see coming, is that -- and this is not different from a lot of the other infrastructure issues that the province is facing as well -- we need to get ahead of our replacement schedule or have at least a reasonable replacement schedule for our assets, or at some point we're just pushing that problem into the future.[137]
>
> MR. SANDERS: And in fact it may be more. We have not done a calculation to determine the total replacement value of our assets, and I suggest it is significantly more than $1.8 billion. But again, that is what the asset planning process is intended to provide, is an optimized, informed view of what is a reasonable life cycle for our assets, and that is what we're endeavouring to do.
>
> Now, we have gone through two cycles of the asset planning process, and we are looking to enhance and improve that process to get better information and better outcomes.[138]
>
> MR. SANDERS: Not necessarily. In fact, how you even treat the risk may change as we look at our view on what those risks are and how we manage them.
>
> So in a more sophisticated view of the life cycle of the assets, we may come up with different alternatives than simply repair. We could extend the life.

[137] Tr. Vol. 5, p.129, lines 17-28.
[138] Tr. Vol. 5, p.130, lines 3-12.

> We can look at different repair methods, different survey and condition monitoring programs, perhaps, to extend the life of the assets.[139]

Board staff asked about asset life assumptions used by Gannett Fleming.

> MS. SEBALJ: Okay. And was it ever suggested that longer asset lives should be used in your study?
>
> MR. KENNEDY: Yes. And in fact, we recognize those comments in our study.
>
> I think we need to understand the context that -- and I wasn't here for Mr. Sanders' entire cross-examination,
> but similar comments have been made in a number of jurisdictions, where I've provided testimony by operations staff.[140]
>
> So right now the level of retirement activity is appropriate for that, but we see in studies -- and we've seen it with this company in terms of cast-iron -- it comes out in big bunches. So there will be a point in time -- and I've seen it now in Alberta a lot, with 1970-era pipe -- that pipe is an asset that once it ages, it ages fast and you start having issues, and you will need to retire it in larger groups.
>
> I guess what I'm saying in a long way short is I'm not convinced that they're always, forever and a day, only going to retire 100 kilometres of pipe per year. I think there are going to be times where that rate will drastically increase.
>
> This company is a company of somewhat aging infrastructure. There is an awful lot of coated steel pipe in the ground that went in in the late 1950s and early '60s. So that's getting to 60 years now.[141]
>
> And I think Mr. Sanders was talking to you from, like, a capital investment aspect or perspective. My perspective is maybe a little bit longer in nature, in terms of how technologies replace themselves over the long term. And I guess what I'm saying to you is I'm not convinced that we'll see pipe with 300 years of life in it. There is obviously going to be some shortening or some acceleration of the retirement activities at some point in time, in this company's future and in virtually every gas utility's future.
>
> And I'm dealing with that now, for example, in Alberta, where they are replacing all the pipes that went in in 1970. If you had asked them in the

[139] Tr. Vol. 5, p.130 (lines 21) - p.131 (line 1).
[140] Tr. Vol. 9, p.128 (line 23) - p.129 (line 3).
[141] Tr. Vol. 9, p.129 (line 14) - p. 130 (line 2).

> year 2000 if that was going to occur, it didn't, but that pipe came to a certain point in time in its age, and the chemical aspects of that pipe, for that plastic pipe that was manufactured in the early 1970s in Alberta, it started to fail in mass.
>
> And so we got programs that we're replacing tens or thousands of kilometres of pipe per year, not hundreds.[142]
>
> MS. SEBALJ: I think Staff's point was that -- and obviously there are assets in the ground that will, as you say, come up for repair or replacement. However, the new assets -- I mean, at least what we heard in evidence was that the new assets were likely to extend the life, the plastic pipe, and the more resilient pipe, by definition, is being put in the ground for the purpose of lasting longer and not deteriorating as quickly, is it not?
>
> MR. KENNEDY: One would hope. And the pipe -- the new pipe that is going into the ground, so I would say pipe post-1995, thereabouts, is expected to have a longer service life than the pipe that went into the ground prior to that, and definitely longer than the -- for example, the coated steel pipe that perhaps is in the ground.[143]

Board staff questioned Mr. Kennedy on studies prepared for different regulators.

> MS. SEBALJ: Are we saying that the utility of those studies is questionable, because we can't actually predict with any certainty whatsoever what the useful life of the assets is?
>
> MR. KENNEDY: No, I don't think we can anticipate the forces of retirement. Now, the life of pipe is dependent on many things. One is the actual pipe itself. Second,
> such as third-party strikes. You have the capacity of pipes that require replacement. You have -- in the case of Alberta we are seeing the chemical composition of the pipe that didn't meet the anticipated standards or didn't live up to its ability, if you will, at that point in time.
>
> There's a number of factors. And as we start to see occurrences and trends that this pipe lasts longer, we will be extending the life of the pipe to appropriately match those observed observations at that point in time.
>
> My point is that there's a number of different eras and different technologies of pipe within the Enbridge system right now. They are not all the brand-new really long-lived pipes.

[142] Tr. Vol. 9, p. 130 (line 11) - p. 131 (line1).
[143] Tr. Vol. 9, pp.132, lines 13-26.

> MS. SEBALJ: And the purpose of the SRC reserve is to deal with exactly those sorts of contingencies, isn't it?
>
> MR. KENNEDY: Yes, it's --
>
> MS. SEBALJ: So if you have to suddenly retire a lot more pipe than you had originally planned because of chemical corrosion or whatever -- I won't pretend that I understand -- deterioration of the pipe, this fund -- this reserve is intended to deal with exactly that eventuality, correct?
>
> MR. KENNEDY: Oh, it is. It's intended to be our best estimate of the funds that would be required to retire that pipe for whatever reason cost -- or cost for whatever reason.[144]

Board staff submits that Enbridge has supported its requirement for SRC. Due to future uncertainty of the urgency of asset replacements, Board staff does not support the refund of any amount of the SRC reserve of $900 million. Board staff does not oppose the use of the CDNS methodology, but Board staff submits that it should not be implemented until the new asset plan approach has been completed by 2018.

(c) Amount of SRC to be Recovered 2014-2018

In answer to Board staff interrogatory #77[145], Enbridge filed a table that shows the history and the forecast of SRC since 2009 through 2018. The amounts proposed to be recovered from ratepayers for SRC from 2014 to 2018 are in total $247.3 million. [Line #3 on the table.] For the same period, the proposed refund to ratepayers is $259.8 million. [Line # 6 on the table.] Enbridge forecasts to spend $76.4 million in the test period. The ending liability balance is shown as $815.1 million.

The undertaking reply J9.2 using a discount rate of 4.95% shows the following amounts for the period 2014-2018. Recoveries from customers of $73.8 million; refund to customers of $503.1 million; and, proposed spending of $76.4 million. The ending liability balance is shown as $398.2 million.

The sensitivity to the selection of the discount rate can be seen by comparing the ending 2018 liability balances, the amounts to be recovered and the refund to customers.

[144] Tr. Vol. 9, p.133 (line 22) - p.134 (line 26).
[145] Ex. I.E40.EnbridgeI.Staff.77, Attachment 1.

Enbridge has disclosed in its 2013 audited financial statements a liability for SRC of $905 million. The forecast amount in IRR Staff #77 is $903.9.

Board staff submits that based on the evidence, $900 million is the most reasonable amount available on which to base any conclusions about the quantum of SRC required by Enbridge at the end of 2013. Enbridge's management, lawyers and auditors have signed off on this number.[146]

The Board has approved the recovery of net negative salvage as a component of depreciation since at least 1959.[147] Board staff does not challenge the approval to collect SRC from ratepayers. Board staff questions the quantum to be recovered during the test period. Board staff does not suggest the pause approach since Enbridge will require in future years more than $2 billion and less than $5 billion to be collected from ratepayers.

In IRR Staff #77, the amount to be recovered is $247.3 million and the proposed refund amount is $259.8 million. The amounts basically offset each other and neither Enbridge nor the ratepayers would be harmed by not collecting or refunding either amount.

Board staff submits that a reserve or liability of $900 million is adequate for the test period ending 2018. Board staff submits that the amount of SRC to be recovered in the test period should be the total amount of $76.4 million to be spent.[148]

Enbridge proposes to recover $247.3 million of SRC in the test period. Board staff's submission to restrict SRC recovery to $76.4 million for the test period will result in a reduction in gross revenue requirement of the difference between these amounts of $170.9 million for the period 2014-2018.

(d) Regulatory Liability Owing to Ratepayers and Need for Segregated Fund

Board staff asked Enbridge about whether the SRC is refundable to ratepayers based on definitions in Enbridge's 2013 audited financial statements.[149]

[146] Tr. Vol. 9, p.41, lines 19-24.
[147] Ex. I.E40.EnbridgeI.Staff.84.
[148] Ex. I.E40.EGDI.Staff.77, Attachment 1: In $ millions: 2014, $15.9; 2015, $15.8; 2016, $14.9; 2017, $14.9; 2018, $14.9; total $76.4.
[149] J1.1, 2013 audited financial statements.

> MR. CULBERT: It is a general statement about the general concept of regulatory assets and liabilities. To look at the details, further details of what is really constituted in the regulatory liabilities, note 10, sorry, on -- page 16 at the bottom, page 19 of 44 at the top, note 10 shows what a portion of the liabilities are, and they are future removal and site restoration reserves, and it
> goes on to explain what those are, that they are not amounts payable to ratepayers; they are amounts to be used for future removal costs.[150]
>
> MS. SEBALJ: So the position, then, is that it is not owing to customers, but you are returning it to customers?[151]
>
> MR. CULBERT: Yes. As we've stated, this is a re-estimation of the reserve amount we believe we need, given our view of our remaining asset lives that we have in the ground today. And this is an excess reserve amount that has been collected that, upon re-estimation, we are proposing a return of those amounts in the manner that we have proposed.
>
> You could do it through a multitude of means, as Mr. Kennedy has spoken about.
>
> MS. SEBALJ: Okay. And there was some discussion about this this morning, but you've -- it's been said on the record that there is no fund where these monies are -- reside, and that the monies that are recovered for SRC are used -- I can't remember what you called it, general -- you said general --
>
> MR. CULBERT: When the company looks at its planning for cash flow purposes, all of its cash inflows, outflows, are part of its forecast of cash requirements.[152]
>
> Because if we aren't able to use all of the cash flows of the entity to perform all of our activities, if we had to set this aside, then we wouldn't have this cash to utilize, and we would have had to have issued debt and equity, and our rate base would be higher by $900 million.[153]

Board staff submits that $900 million dollars collected from ratepayers is a material amount. The future retirement costs already discussed of between $3 and $5 billion will continue to add to the liability. Board staff submits that the Board may want to require Enbridge to produce a report on the implications of requiring Enbridge to set aside these

[150] Tr. Vol. 9, p.114 (line 22) - p.115 (line 3).
[151] Tr. Vol. 9, p.115, lines 27-28.
[152] Tr. Vol. 9, p.116, lines 1-18.
[153] Tr. Vol. 9, p.117, lines 3-7.

very large collections from ratepayers for asset replacements decades in the future in a segregated fund or irrevocable trust. Staff suggests that the filing of such a report may coincide with and form a part of the 2014 ESM application expected at about April or May of 2015.

B. Rate 125

Elenchus Research Associates presented expert cost allocation evidence in response to issues raised by the Association of Power Producers of Ontario (APPrO). The issues concern Enbridge Rate 125 customers (comprised of a total of 5 gas-fired power generators) and whether the existing allocation methodology should be changed to reflect better cost causality and whether future excess capacity in the system creates a situation whereby Rate 125 customers are paying twice for this capacity.

Elenchus' recommendations are that:

- Enbridge's CAM should distinguish between high and low capacity XHP assets so that these assets can be allocated in a manner that better reflects cost causality principles. Enbridge should allocate to Rate 125 customers only costs of XHP assets that meet the physical specification of facilities that can be used to supply services to them.

- In order to avoid Rate 125 customers paying in two ways for the excess capacity required in the Enbridge system to accommodate future growth efficiently, Enbridge should be directed either to amend its economic feasibility test as it applies to Rate 125 customers or to modify its cost allocation methodology so that Rate 125 customers are not required to pay for excess capacity in the system in two ways.[154]

Enbridge has reserved its right to formally respond until later (presumably in Reply argument) because of confusion that surfaced at the hearing over whether APPrO will advance its experts opinions in argument, or take another approach.

> The Company understands that APPrO will be arguing for changes to cost allocation methodology for Rate 125. While APPrO filed an expert report containing recommendations around changes to cost allocation for Rate 125, it became clear during the hearing that APPrO's position may differ from that presented in the Elenchus report. As APPrO may choose to advance a position

[154] Ex. L, Tab 2, Sch. 1, p. 7, verbatim.

> that differs from the views or recommendations set out in the Elenchus report, Enbridge will wait until having reviewed APPrO's argument about Rate 125 before providing a response [155]

However, Enbridge's company witness on cost allocation and rate design, Mr. Kacicnik, revealed his opposition to Elenchus' proposals at the hearing.

Mr. Kacicnik made a number of points, among them:

- Delivery charges on Rate 125 are considerably lower than delivery charges on other Enbridge's rates.
- The Company operates an integrated gas distribution network and has long used the "postage-stamp ratemaking" approach which means that no matter the customer's location, be it Ottawa or Niagara or Toronto, each class of customer will have the same rates. Postage-stamp ratemaking also means that all services have their costs calculated on an average cost basis. All customers therefore share in the mix of investment vintages, no matter how old the pipes, or when they were placed into service.
- The impact of the first Elenchus recommendation is roughly $1 million a year for Rate 125 customers meaning that $1 million would need to be recovered from other rate classes.
- The second Elenchus recommendation dealing with excess capacity on the system is essentially that what is deemed "excess capacity" on the system would not be allocated to Rate 125 customers. This is about $500,000 per year of costs which would also need to be recovered from the other rate classes.
- The total impact of the two Elenchus proposals is roughly $1.5 million.

The Company stated that it would be inappropriate to deviate from the existing Board-approved methodology. If the Board were inclined to do so, the Company said that the issues should be looked at on a broader basis, rather than only on the basis of treatment of specific investments related to a specific class of customer.

Staff Position

Staff's view is that the Elenchus proposals should be rejected. The proposal runs contrary to accepted principles of postage-stamp ratemaking for Enbridge. Board staff also agrees with Enbridge that if the Board were inclined to further examine this issue, it should do so on a broader basis, rather than only on the basis of treatment of specific investments related to a specific class of customer.

[155] Argument in Chief, p. 77.

C. Annual Stakeholder Meeting

Board staff has taken note that there is an Annual Stakeholder Meeting included as a feature of the Board-approved Union Gas Settlement Agreement addressing Union's 2014-2018 multi-year incentive ratemaking framework. The description of the stakeholder meeting is as follows:

> 12.2 Annual stakeholder meeting
>
> (Complete Settlement)
>
> The parties agree that Union will hold an annual, funded stakeholder meeting (including funding for reasonable preparation for the meeting and follow up comments from the meeting), after the public release of year-end financial results but prior to Union filing its annual non-commodity deferral accounts disposition application (March/April timeframe). At the stakeholder meeting Union will:
>
> 1. Review previous year's financial results (i.e. earnings, capital spending) and other key operating parameters (i.e. SQI performance) for the most recently completed year;
>
> 2. Present and explain market conditions and expected changes/trends, and the impact these may have on the regulated operations;
>
> 3. Present and review the gas supply plan for the coming year;
>
> 4. Present new capital projects that meet the capital pass-through criteria as defined in Section 6.6; and,
>
> 5. Present results of any customer surveys undertaken during the year.
>
> Union will file all information resulting from this annual meeting with the Board and ensure it is available to any party not able to attend.
>
> The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC
>
> The following parties take no position: Six Nations, TCPL [156]

In Board staff's submission, a similar Annual Stakeholder Meeting held at a similar time of the year (i.e. shortly after the release of the year-end financial results) would be of value to Enbridge, its stakeholders and the Board. Board staff submits that the Board

[156] Ex. K1.4, page 28.

may wish to consider establishing an annual requirement for Enbridge to hold such a meeting.

D. Effective Date of the Rate Change

Enbridge has requested that the effective date of the rate change be January 1, 2014. Enbridge is currently operating on interim rates which, contrary to the usual case, are actually higher than the requested 2014 final rates. Enbridge has proposed a Rider E which will credit ratepayers with the difference in revenue between interim and final 2014 rates for the period from January 1, 2014 to the date that final rates are implemented.[157]

Given the intensive nature of the issues, it should have been clear to Enbridge that final rates would not be available to be in place for January 1, 2014 when the application was filed in July 2013. In the normal course, the final rates ought to become effective in the month following the issuance of the decision and order. However given that the 2014 applied-for rates represent a decrease (even without the offsetting SRC rider credit), staff's view is that any revenue credits realized with the implementation of the final 2014 rates should be to the credit of the ratepayer and not the shareholder.

[157] Argument in Chief, page 78.

Staff Submission and Recommendations

A. The Proposed Customized IR Plan

Staff has outlined a number of overarching concerns related to the robustness of the evidence tendered to support the required elements of Enbridge's Proposed Customized IR Plan and to the imbalance of risk and reward embedded in the proposal.

As discussed above, Staff is also aware that this is the first rate application made to the Board under the Custom IR framework. This framework is new to the Board, to applicants, intervenors and Staff. It is therefore appropriate that some testing of the concepts would be expected even in the electricity distribution context, to which the RRFE Report and the articulated framework outlined were directed. Given that the first application of the Custom IR type has been made by a natural gas distributor, the application of the Custom IR theory into practice is all the more challenging.

The issue remains, however, that the lack of adequate benchmarking evidence creates difficulty for the Board. The Board should not, in Staff's submission, allow a utility to embark on a five-year customized IRM without having confidence in the reasonableness of its forecasts (ideally, through robust asset management planning, a third party engineering assessment of the asset management plan and thorough and effective benchmarking). The Board needs to have confidence in the utility's ability to undertake, document and show real productivity and efficiency gains through the period. In staff's view, the Board should also ensure that the plan appropriately allocates the risks of over or under-earning as between ratepayers and shareholders.

In particular, care must be taken, in staff's view to ensure that ROE, which already includes an equity premium to account for risk, is not layered on top of more focused risk management levers available to rate regulated utilities such as deferral and variance accounts, annual updates, Z-factors, Y-factors, etc. Given that Enbridge is a utility that has consistently exceeded its allowed rates of return over the last 15 years, this issue is especially worthy of careful examination in the present case.

Staff therefore submits that the Board should adopt one of two alternative proposals[158] in making its decision with respect to the appropriateness of Enbridge's Proposed Customized IR Plan:

[158] Please note that these proposals relate only to the Proposed Customized IR Plan. Further submissions are made with respect to the individual aspects of the Enbridge filing (e.g., ROE, DVAs, Z-Factor, SRC, etc.) later in the document.

(1) Interim Rates and New Peer Group Analysis

Maintain the current rates as interim and order Enbridge to file additional evidence to address the shortcomings in its proposal. In particular order Enbridge to file more appropriate evidence on the benchmarking of capital costs which we know make up more than 60% of the proposed expenditures over the plan term.

In particular, the Board could require Enbridge to choose a more representative peer group and conduct a total cost benchmarking analysis and ranking as per the request in TCU 1.11. While the Board has actually expressed a preference for econometric rather than peer group benchmarking, no econometric study has been presented in this case, and it would be unduly burdensome and time consuming to develop such a study at this time. However, CEA has provided a peer group benchmarking study, and that study can be expanded relatively easily in a manner that would lead to more robust and accurate inferences on Enbridge's total cost performance.

The new peer group should, at a minimum, include Union Gas Limited and the other peers in the industry group which had customer growth rates greater than 2%.[159]

In order to ensure a robust study (sample) group, however, staff submits that the two most important criteria that are neglected by CEA are: 1) customer growth; and 2) the percent of gas distribution main that is not cast iron or bare steel. PEG's analyses and evidence show that both are significant drivers of gas distribution costs. In staff's submission, they are also both relevant business conditions for Enbridge, which is the most rapidly-growing distributor in CEA's sample[160] and has undertaken an extensive replacement program that has reduced cast iron and bare steel mains to less than 1% of Enbridge's gas distribution main[161] which is far below the average in the region.

In the US, most, but not all, of the high-growth and low bare steel/cast iron distributors are in the Southeast, Southwest, and on the West coast. Examples of distributors that satisfy these criteria and which could be included in a more representative sample of North American gas distributors include:

- Southern California Gas
- Pacific Gas and Electric (CA)
- San Diego Gas and Electric

[159] Northwest Natural Gas Company at 2.55%, Puget Sound Energy, Inc. at 2.41% and Questar Gas Company at 2.39%.
[160] Tr. Vol. 3, pp. 22-26.
[161] Ex. L, Tab 1, Sch. 2, p. 39.

- Cascade Natural Gas (WA)
- Southwest Gas (AZ and NV)
- Piedmont Natural Gas (NC)
- Public Service of North Carolina
- New Jersey Natural Gas
- Atlanta Gas Light
- Alabama Gas

Each of these distributors was either used by PEG in its own TFP benchmarking work (which was filed in this case) prior to this proceeding,[162] or was specifically raised as a possible peer[163] during the course of the hearing.

Including these distributors will lead to better estimates of TFP growth for the North American gas distributors and more robust and accurate inferences on Enbridge's total cost efficiency because they are no longer being compared to slow growth distributors with aging infrastructure.

Should the Board adopt this option, it would necessarily require the review and testing of the evidence following the filing by Enbridge. Staff submits, however, that the evidence is fairly narrow and that, depending on the outcome of the analysis, a written review process followed by focused written submissions would likely be sufficient. Staff expects that the benefits of having this evidence, which would give the Board more ability to assess the forecasts and therefore to set just and reasonable rates with greater confidence outweigh the "costs" associated with the delay caused. Because this study will still be backward looking, it still will not "allow" the Board to assess forward-looking cost forecasts per se, but it will improve the benchmarking evidence and improve the Board's information set more generally. This is particularly so, given that Enbridge's proposal will determine how rates are set for five years.

(2) Approve Plan but Reduce Revenue Requirement and Impose Stretch

Approve the Proposed Customized IR Plan, including the $172.5 million which Enbridge says is embedded productivity, but impose a reduction to the revenue requirement of $20 million per year (total amount $100 million) to ensure that an appropriate amount of

[162] Ex. I.A1.Staff.Enbridge.9.
[163] Tr. Vol. 3, pp. 112-113.

productivity is incorporated into the plan; and apply a "stretch" factor of 0.60%[164] per year which would help overcome or compensate for any over-forecasting of costs in the plan, and provide a transparent incentive for the Company to seek initiatives to improve productivity and efficiency of operations on a sustainable basis. The details of both the productivity amount and the stretch factor, including the associated rationale are discussed below.

(i) Reduce Revenue Requirement

In light of staff's views on the Customized IR Plan articulated throughout this submission, staff recommends an amount representing productivity be imposed on Enbridge. The Incentive Ratemaking construct is premised on the achievement of adequate productivity and efficiency gains which are measurable and where possible, sustainable. Enbridge has not, in staff's submission convincingly demonstrated the existence of productivity in its plan. The evidence in the current case, as discussed in staff's submission is that Enbridge lacks a convincing plan to achieve sustainable productivity and efficiency gains in the current plan term. Staff's view is that a customer benefit amount needs to be imposed to provide a better foundation for the plan.

Staff submits that it is appropriate to reduce the revenue requirement by an amount of $20 million in each year of the plan. There is support for this found in the evidence.

First, there is evidence of exceptional weather-normalized ROE performance for the past 14 years. The pattern shows that on a weather-normalized basis, Enbridge outperforms the Board-approved ROE typically in a range of 100 to 200 basis points.[165]

During the most recent IR plan, between the years 2008 to 2012, Enbridge produced gross over-earnings of $146.2 million.[166] The average per annum over-earnings is $29.2 million during this period. Enbridge's results for 2013 demonstrated exceptional earnings once again, at $31.2 million higher than the Board-approved level.[167]

Second, Enbridge Inc.'s Strategic Plan covering its gas distribution business unit (termed "GD") was produced at the hearing.[168] It included a "GD Stretch", presumably

[164] See analysis below.
[165] Ex. I.A1.EnbridgeI.STAFF.4.
[166] J1.3 Enbridge clarified in a footnote that these amounts include the impact of 100bp earnings sharing and taxes payable.
[167] J1.2 p. 3.
[168] J1.4.

to represent additional amounts of earnings over and above a basic level thought to be achievable over the plan term. A simple average of the amounts over the years 2013 through 2016 shows $20 million per year.[169] Staff understands that Enbridge Gas Distribution (the Ontario utility) represents a very large portion of this business unit. Staff suggests that it is reasonable to presume that the Company itself believes there is something in the order of $20 million per year available as stretch earnings. It is noteworthy that the prediction for 2013 was close to what actually happened. The Strategic Plan had forecasted the GD Stretch at $27 million and in fact, Enbridge's earnings were $31.2 million above plan.

Finally, Enbridge's memo to its Board of Directors concerning the instant application included a paragraph about a "stretch objective", clearly indicating that Enbridge management itself believes it can produce over-earnings during the plan.

> The proposed IR model sets out the forecast cost of service inclusive of productivity and efficiency. In addition, Management plans to make every effort to find further efficiency opportunities and by taking this into account has set a "stretch" objective of achieving earnings modestly above the allowed ROE on average of 60 bps per year.[170]

Board staff observes the use of the word "modestly" in the paragraph above could be construed to mean that management believes it can perform even better than the 60 bps referenced. Indeed, its robust historical earrings pattern would support this. Staff notes that 100 bps on ROE is about $20 million in earnings.[171] If the "modest" 60 bps over-earnings actually materializes into something higher, which is the inference, then based on historical over-earnings staff submits that 100 bps of ROE over-achievement is not at all out of the question.

Staff submits that the Board should impose at least a $20 million per year reduction to the revenue requirements proposed. This would be $100 million over the plan term.

[169] Staff did not include the 2017 stretch amount as it appeared much smaller than the others and therefore thought to be an outlier.
[170] Ex. I.A1.EnbridgeI.CCC.2, Attachment 1, p. 4 of 5.
[171] Ex. I.A1.EnbridgeI.CCC.2, Attachment 1, p. 5. See sensitivity analysis where ROE at 50 bps is about $10 million in earnings and 100 bps would be about $20 million.

(ii) Stretch Factor

In its Rate Setting and Benchmarking Report,[172] the Board states:

> Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation. However, the Board in its RRF Report concluded that is will make the stretch factor assignments under Price Cap IR on the basis of total cost benchmarking evaluations…

Stretch factors are consumer benefits. They take effect immediately and are not dependent on the realization of any productivity gains, excess earnings or on future performance of the distributor.

Staff also notes that in the RRFE Report under the Rate-Setting Overview in Table 1 entitled “Elements of Three Methods”, for the Custom IR method, under “Sharing of Benefits” it says “…stretch factor “case-by-case”. Therefore the Board specifically contemplated the use of stretch factors in a Custom IR framework.

The application of a stretch factor in the current case would, in Staff’s view, help overcome the difficulty the Company has in “proving” that productivity exists in the plan by imposing a known value which is external to the plan and represents and immediate benefit to the consumer. The stretch factor would be applied from the outset of the implementation of the plan and thus force some additional measure of productivity on Enbridge.

In the Rate Setting and Benchmarking Report, the Board determined that appropriate stretch factor values for electricity distributors range from 0.0% to 0.6% based on a distributor’s actual costs relative to its predicted costs,[173] as determined by PEG’s econometric model of Ontario electricity distributors’ total cost performance. The table below shows the assignment of stretch factors to different groups of distributors:

[172] EB-2010-0379, Report of the Board entitled Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario’s Electricity Distributors (Issued on November 21, 2013 and as corrected on December 4, 2013), p. 19.
[173] EB-2010-0379 Draft Report of the Board dated September 6, 2013, p. 28.

Group	Relative Cost Performance	Stretch Factor
I	Actual costs 25% or more below predicted costs	0.00%
II	Actual costs 10-25% below predicted costs	0.15%
III	Actual costs within +/- 10% predicted costs	0.30%
IV	Actual costs 10-25% above predicted costs	0.45%
V	Actual costs 25% or more above predicted costs	0.60%

Staff submits that this is an appropriate framework to use to assign a stretch factor to Enbridge.

Because Enbridge only undertook partial cost benchmarking, however, it is not immediately clear where the Company ranks against its peers on a total cost performance basis. Given that this benchmark is far less precise than what would have been possible if appropriate total cost benchmarking were available in the current case, Staff submits that a Group V assignment, which results in a 0.60% stretch factor, would not be inappropriate for Enbridge.

As with the electricity distributors, the stretch would be applied after the rates are established for 2014. The first year would be a cost-based year with prices set and efficiencies built in. This would be represented by the Board's approval of the 2014 revenues. The stretch would then be applied going forward in each year 2015 to 2018.

Staff has considered the rationale for imposing such a factor and offers the following:

- The Incentive Ratemaking construct is premised on the achievement of adequate productivity and efficiency gains which are measurable and sustainable.
- The evidence in the current case, as discussed in staff's submission is that Enbridge lacks a solid plan to achieve productivity and efficiency gains in the current plan term. Staff's view is that a stretch factor would provide an appropriate mechanism to support the creation of such a plan.
- A stretch factor of 0.6% would translate to a range of about $6.3 – $7.8 million per year on revenue requirement (net of gas costs) for Enbridge over the term.

B. Summary and Conclusion

In Board staff's submission implementation of one of the alternative proposals outlined in (1) or (2) above would address some of the shortcomings related to the forecasts provided by Enbridge in support of its plan, the benchmarking or those forecasts and the requirement to include productivity within the plan.

Board staff submits that for the reasons articulated in each of the specific sections above, however, other elements of Enbridge's application must be addressed in addition to the implementation of one of the proposals staff has made to address the Proposed Customized IR Plan itself.

In particular, and for the reasons set out in greater detail above, Board staff submits that the Board should reject the SEIM proposal, set ROE at a constant level throughout the plan term, increase the materiality threshold for the Z-factor to $4 million, reject the proposed relocations and mains variance accounts, modify the transactional services proposal to embed additional amounts in rates, and eliminate the variance account for regulatory costs.

With respect to the Site Restoration Costs proposal, Board staff submits that it is appropriate to remove the SRC amounts proposed to be recovered from ratepayers over the plan term ($247.3 million) from rates, but to continue to collect in rates the amount proposed to be spent on site restoration activities ($76.4 million). The net of these two amounts represents a savings to ratepayers of $170.9 million.

In summary, staff's proposals under recommendation (2) would, if accepted in their entirety by the Board, represent the following revenue reductions over the plan term.[174]

($ millions)

Productivity	100.0
Stretch Factor 0.6%	28.6
Transactional Services	60.0
ROE at 2013 Board-approved level	130.0
SRC	170.9
Total	**489.5**

[174] Figures are estimates only and do not include tax or other impacts. Staff expects that all figures would, if ordered by the Board, be subject to a Draft Rate Order review process and be finalized, after the Decision and Order is released.

In the context of the requested revenues over the 5-year term of $13.5 billion, the reductions represent about 3.6%. Staff's view is that this is not unreasonable.

\- All of which is respectfully submitted -