# SCHOOL ENERGY COALITION INTERROGATORIES

**SEC-OEBStaff-1**

**Reference:** [Ex.M, p.8-9]

PEG states: "If, alternatively, the Board opts for a Capital-factor (C factor) approach, similar to what the OEB has approved for Custom IR plans for Hydro One distribution and Toronto Hydro, our recommended CPEF formula is Inflation – 0.3% + growth Customers, where the X factor is the sum of a 0% base TFP growth trend and a 0.3% stretch factor."

Please explain why PEG believes an additional amount to represent customer growth should be applied to the C-Factor in a Revenue Cap Index, where presumably growth related capital needs are included in the proposed capital plan, and changes in load are incorporated into the annual load forecast.

**Response to SEC-OEBStaff-1:**

The scale escalator term of an RCI affords compensation for growth in cost due to growth in output that is not addressed by the I - X terms. A C factor compensates a utility for the difference between its approved capital cost growth and the growth in capital revenue that the RCI otherwise provides. Thus, the addition of a scale escalator to the formula reduces the need for a C factor. This, combined with a more effective materiality threshold, can reduce the need for Custom IR and discourage its continual use. Please see Section 3.1 of PEG's report and the response to M-HOL-12 for further discussions of the G factor issue.

**SEC-OEBStaff-2**

**Reference:** [Ex.M, p.19]

PEG notes that Hydro Ottawa's previous Hydro Ottawa Custom IR plan included an 'Efficiency Adjustment Mechanism'.

Under that approach, Hydro Ottawa used the annual OEB stretch factor assignments to determine if an entry into the account was required. If the OEB approves either the Clearspring or PEG stretch factor, based on either consultants customer benchmarking model, is it possible for a similar mechanism to be implemented for 2021-2025, without the need for Hydro Ottawa (or the OEB) to retain either Clearspring or PEG to re-run their customer benchmarking model each year based on actuals? Is there a simple way that Hydro Ottawa's annual cost performance could be calculated and able to be compared to either the Clearspring or PEG results? If so, please explain.

**Response to SEC-OEBStaff-2**

PEG believes that the Clearspring and PEG benchmarking models presented in this proceeding provide a better basis for a Hydro Ottawa stretch factor than the 4GIRM total cost model. Incentives are strengthened if the Company's stretch factor is recalculated annually using one of the new models and the most recent available data. The cost of such an exercise would be greatly reduced if the econometric benchmarking model was not revised. However, the task would not be trivial.

The closest example is the spreadsheet model used as part of the annual updates to the stretch factors which are usually released each August (this year the release will be in September due to the delays arising from COVID-19 and the filing of RRR data). At the start of the project to do the first 2013 update, PEG discussed with OEB staff the possibility of trying to set up the calculations such that OEB staff could do it in the future without PEG's involvement. OEB staff thought there was value in having an independent consultant do the calculation. It is also the case that the calculations, even in spreadsheet form are sometimes complex. A number of years ago the OEB approved a project to provide additional materials and a workshop for the distributors to better explain the benchmarking calculations. The project made the calculations more transparent and accessible.

In the context of Hydro Ottawa, someone would have to take responsibility for the calculations and they would require review. Either Clearspring or PEG would have to do the calculations or develop a straightforward spreadsheet so that the Company could do them itself.

The calculations are simplified in that only one company as opposed to over 60 are being benchmarked. Overall, the proposal has some merit, but there would be some work to implement it.

**SEC-OEBStaff-3**

**Reference:** [Ex.1-1-10, p.20-24]
Hydro Ottawa has proposed to use a custom weightings for its OM&A inflation calculation that represents its own non-labour/labour split, as opposed to the OEB's standard 70%/30% weightings.

In PEG's view, should the non-labour/labour weightings for the purpose of determining the inflation amount in a custom index be based on a utility's own actual or forecast split, or based on an industry weighting? Please explain your answer.

**Response to SEC-OEBStaff-3:**

The original 70/30 weights on the OM&A input price index were determined by OEB Staff. This was done because OEB data needed to be used in the calculations but the required labor data were confidential. This restriction is not applicable in this case since Hydro Ottawa has reported Company labor cost data.

If the CPEF applies only to OM&A review, PEG believes that the weight on the labor price subindex should ideally be the share of OM&A labor in the total OM&A expenses to which the CPEF applies. If the CPEF applies to capital revenue as well, the labor weight should ideally be the share of OM&A labor expenses in the total revenue requirement to which the CPEF applies.

Sample average or company-specific weights can both be reasonably used in these calculations. Sample average weights have better incentive properties. However, Company-specific weights are acceptable for this proceeding because the 70/30 weights are out of date and markedly different from the Company's.

**SEC-OEBStaff-4**

**Reference:** [Ex.43-44]

Please provide a copy of the referenced Berkeley Lab report and the testimony for the Massachusetts Attorney General's office.

**Response to SEC-OEBStaff-4:**

Please see Attachment SEC-OEBStaff-4 for the requested Berkeley Lab report and Attachment 6 of the OEB Staff IRs filed May 8, 2020, and referenced in 1-OEB-36, for the requested testimony by PEG for the Massachusetts Attorney General.

**SEC-OEBStaff-5**

**Reference:** Hydro Ottawa has proposed a Growth Factor for its OM&A index formula. SEC understands this formula to reflect the additional OM&A required for the forecast increase in customer additions. In its formula, Hydro Ottawa has proposed a scaling factor of 0.35% (i.e. for every 1% increase in customer, OM&A should increase by 0.35%).

a. Please confirm that this is PEG's understanding of the Growth Factor.

b. Does PEG believe that the scaling factor should be based on a utility specific amount or an external industry benchmarking amount?

c. Please provide PEG's view on a scaling factor generally.

d. Please provide PEG's view on the proposed 0.35% scaling factor.

**Response to SEC-OEBStaff-5:**

a. PEG confirms this statement.

b. Dr. Lowry believes that the scale factor should be based on a Company's actual or forecasted output growth. This approach reduces utility operating risk and windfall gains and losses without weakening the utility's performance incentives.

c. Please see Section 3.1 of PEG's June report and the response to M-HOL-12 for further discussion of the scaling factor issue.

d. Please see Section 3.1 of PEG's June report and the response to M-HOL-12 for further discussion of the scaling factor issue.

**SEC-OEBStaff-6**

**Reference:** [Ex. M, p.67]

PEG states: "Note also that no consideration has been paid, in the Company's past or current plan, to any special *advantages* Hydro Ottawa has in managing its costs. These advantages have included in the past, and may in the future continue to include, comparatively brisk customer growth that increases opportunities to realize scale economies. The OEB's 0% base productivity trend applies to all Ontario utilities and is effectively an industry standard."

Please elaborate.

**Response to SEC-OEBStaff-6:**

In its RRF deliberations, the OEB decided to base the base productivity trend for all Price Cap IR distributors on TFP research for an aggregation of Ontario power distributors.[1] The Board stated on page 23 of the *Rate Handbook* that the base productivity trend is "a fixed amount for industry-wide productivity". Utilities with a special need for high capex can obtain supplemental revenue from the ACM/ICM provisions of this rate option. However, no adjustment is considered for special cost advantages such as the scale economies that can result over time from unusually brisk customer growth. Dr. Lowry explains in Section 3.1 of his report in this proceeding that the TFP growth of utilities is driven by various external business conditions. These conditions vary between utilities and, over time, for individual utilities. Output growth is a well-known driver of productivity growth due to its ability to produce scale economies. The output growth of Hydro Ottawa has been comparatively brisk thanks in part to the outsized importance of government and higher education in its service territory.

It can also be noted that the work that resulted in the 0% base productivity trend is now almost 7 years out of date.

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[1] This aggregation ultimately excluded Ontario's two largest distributors: Hydro One and Toronto Hydro. The base productivity growth target was not set equal to the TFP trend of the aggregate. Rather, the OEB stated on page 17 of its November 21, 2013 Report of the Board in EB-2010-0379, the IRM4 decision that

> The Board has determined that the appropriate value for the productivity factor (Industry TFP) for Price Cap IR is zero. The Board believes that setting the productivity factor at zero reflects a reasonable balance of the estimated productivity trend in the sector over the last 10 years and a value that is reasonable to project into the future as an on-going external industry benchmark which all distributors should be expected to achieve.

**SEC-OEBStaff-7**

**Reference:** [Ex.M, p.74-75]

PEG notes that a higher S-factor “merits contemplation” and lists several reasons for why this is the case.

What is the specific S-factor that PEG would recommend?

**Response to SEC-OEBStaff-7:**

The response to this interrogatory will be provided by July 10, 2020.

**SEC-OEBStaff-8**

**Reference: [Ex. M, p.85]**

Please further explain the Alberta 'K-Bar' approach to supplemental capital funding. Using Hydro Ottawa's proposed application as an example, please explain what this would look like if the OEB were to apply the approach.

**Response to SEC-OEBStaff-8:**

K-bars are calculated through a multistep process. A summary of the process used to determine Alberta K-bars is outlined in Alberta Utilities Commission Decision 22394-D01-2018, as modified on February 27, 2020. K-bar projects include all capital projects or programs that have historical rate base associated with them at the time of the rebasing application.

Step 1: Calculate the revenues for K-bar projects or programs which are expected from base rates under the I-X mechanism for the first indexing year, 2018.

> (i) Calculate the amount of revenue by program or project recovered in base rates under the I-X mechanism for 2018 using the going-in capital-related revenue requirement by program or project. This is done by calculating the revenue requirement for each project in the rebasing year and escalating it by the values of I-X and the revenue impact of the change in forecasted billing determinants, denoted as Q.
>
> (ii) The amount of revenue by program or project recovered in base rates under the I-X mechanism for 2018 should be determined in a manner consistent with the assumptions and use the same capital additions, retirements, depreciation parameters, and any other parameters utilized in the calculation of going-in rates.

Step 2: Calculate the notional revenue requirement for K-bar projects or programs for 2018. Distributors will need to calculate the 2018 mid-year rate base, which necessarily requires the calculation of both the 2018 opening rate base and the 2018 closing rate base. The closing rate base from the year of rebasing, 2017, should be used as the 2018 opening rate base. As such, all of the assumptions and numbers should be identical to the assumptions and numbers used for rebasing.[2]

[2] An exception was made for distributors that received Commission approval of new depreciation studies subsequent to rebasing.

(i) Distributors will determine the capital additions for each K-bar project for each of 2013 to 2016. The selection of a 4 year average was based in part on the idea that the incentives of PBR were strongest in these years. Inclusion of 2013 data was recommended due to distributor deferrals of capex in that year due to concerns about sufficient funding being provided, while the exclusion of 2017 was recommended to provide a conservative value for K-bar, as distributor capital additions had increased throughout the term of the PBR plan. The exclusion of 2017 data also precluded the possibility of distributor gaming of the mechanism by increasing capital additions in that year.

(ii) Inflate the capital additions to 2017 dollars using the approved I-X and Q, with the approved I factor and Q for each year and the approved X factor for the prior PBR plan.

(iii) Calculate the average K-bar capital additions, by project, in 2017 dollars for the 2013 to 2016 period.

(iv) Inflate the average K-bar capital additions by project to 2018 dollars using the I-X index and Q approved for 2018.

(v) Calculate the amount of K-bar capital cost incurred for 2018, by program or project, based on the 2018 capital additions from Step 2(iv) and the 2017 mid-year rate base. Distributors should use an average of inflation-adjusted retirements from the same period as the capital additions in the calculation of capital cost.

Step 3: Calculate the base K-bar.

(i) Calculate the difference between the 2018 K-bar capital-related revenue requirement required on a projected basis by program or project (from Step 2) and the 2018 K-bar capital-related revenue recovered in the base rates by program or project (from Step 1). The result is the capital funding shortfall or surplus amount for each program or project for 2018.

(ii) Sum the capital funding shortfall and surplus amounts, including both negative accounting test results and positive accounting test results without any materiality considerations, for all Type 2 projects and programs from Step 3(i) to get the total base K-bar for 2018.

The base K-bar is then added to other costs, such as Y and Z factors, and incorporated in rates through annual filings.

For subsequent years, the base K-bar has been calculated in a similar manner, with adjustments made to account for the effects of inflation and productivity represented by I-X, growth in revenue due to changes in billing units represented by Q, and changes to the WACC. The K-bar plant additions from part (iv) of Step 2 of the first year calculations are escalated for I-X and Q. Retirements from part (v) of Step 2 are escalated by inflation. These updated parameters will be used in the K-bar accounting test to calculate the amount of incremental capital funding for a given year.

Prior to undertaking a calculation of K-bars for Hydro Ottawa, it would be necessary to determine if the Company's expiring Custom IR plan serves as the appropriate baseline for capital additions going forward or if an adjustment should be made to allow it to serve as an appropriate baseline. If it was determined that Hydro Ottawa's capital additions from its prior Custom IR plan was the appropriate baseline, PEG believes that Hydro Ottawa's filing provides most of the information necessary to undertake the calculations outlined above, except for the amount of capital additions per project that is currently funded in rates. The Company would need to provide these data in order to undertake these calculations. The calculations could be undertaken as outlined above, substituting references to 2017 with 2021 and references to 2018 with 2022. This would require the application of the OM&A escalator from the prior Custom IR plan term and the determination of an X factor that is appropriate for the entirety of Hydro Ottawa's base rate cost in this proceeding.

**SEC-OEBStaff-9**

**Reference: [Ex.1-1-10]**

Please provide PEG's view on what is a more preferable Custom IR structure, a revenue cap index, as proposed by Hydro Ottawa, or a price cap index, as have been proposed and approved for Toronto Hydro.

**Response to SEC-OEBStaff-9**

Hydro Ottawa has proposed a revenue cap index for OM&A expenses and variance account treatment for its projected/proposed capital costs. The CPEF escalator would be fixed in this proceeding. The revised revenue requirement would be converted into rates using a load forecast that is approved in this proceeding which would not be updated.

Toronto Hydro's recently-approved second Custom IR plan features a custom price cap index which applies to both OM&A and capital revenue. Growth in Toronto Hydro's approved capital revenue is incorporated into the formula and reduced by both the X factor and a supplemental stretch factor. The index is updated each year to reflect the most up to date inflation data. The growth in the price cap index is applied to all rate elements each year.

In the design of multiyear rate plans for energy utilities, PEG generally prefers a combination of revenue cap indexes and a revenue decoupling mechanism ("RDM"). The RDM involves a balancing account and rate riders that adjust rates as needed to cause *actual* revenue to closely track *allowed* revenue. Advantages of this approach include reduced load-forecast controversy, reduced risk from load fluctuations, and strengthened incentives for utilities to promote conservation and demand management. Utilities have more incentive to use rate designs (e.g. peak-load pricing) as a CDM tool. CDM impact evaluations are not needed to compensate utilities for lost margins (though they may still be used to evaluate the performance of utilities in managing CDM programs and to reward good CDM performance). Disadvantages of this approach include the extra regulatory cost of the RDM and passing the risk of load fluctuations to customers.

The advantages of this general approach are reduced in Ontario by the fact that the OEB has (unusually amongst North American regulators) opted for high fixed charges for small-volume distribution customers. This removes the option of time-varying distribution rates for these customers, strengthens distributor incentives to encourage conservation, and reduces load forecasting controversy. Further, the Board has elected to use lost revenue adjustment mechanisms to incentivize utility CDM programs. When these Ontario conditions are taken into account, there is not much practical difference between Toronto Hydro’s price caps and Hydro Ottawa’s proposed revenue caps (if extended to include capital cost recovery).