# SCHOOL ENERGY COALITION INTERROGATORIES

**M1-SEC-1**

**Reference:** Exhibit M1, Page 22

**Interrogatory:**

Please expand on PEG's critique of the loading factor/winter challenge variable developed by PSE.

**Response to SEC-1**: The following response was provided by PEG.

PSE's loading variable is extremely complex. Our primary concerns with this variable are that it lacks transparency and that the value is inaccurate for Hydro One. PEG also has concerns that the variable relies on some additional problematic assumptions. We discuss these problems in turn.

*Complexity*

The loading variable is designed to measure the expense associated with constructing transmission assets due to differing minimum structural strength standards for overhead transmission assets due to local weather conditions. PSE posited that higher minimum structural strength standards would result in increased transmission costs.

The process of constructing this variable had several steps. PSE gathered data from the Canadian Standards Association ("CSA") and the U.S. National Electrical Safety Code ("NESC") on the minimum structural strength requirements for overhead transmission lines in various geographical zones of the United States and Ontario. PSE overlaid maps of each zone, as outlined in CSA Overhead Systems Standard C22.3 No. 1-10 and the NESC, with utility retail service territory maps obtained from Platts. PSE specified a base transmission structure that would be applied to all zones and evaluated the capacity of this structure to function in each zone given the weather conditions which transmission assets are expected to withstand in that zone, as outlined in CSA C22.3 No. 1-20 7.2 and NESC Rules 250B, 250C, and 250D. The weather conditions were not standardized between the CSA and NESC, and the NESC data were complicated by as many as 3 separate sets of weather condition requirements per zone. This analysis was undertaken using software by a third party called Power Line Systems - Computed Aided Design and Draft Lite ("PLS - CADD Lite"). This resulted in what PSE described as a

"Loading Capacity Usage Percentage by Loading Zone," which PSE used, based on the mappings of utility service territories to loading zones, to calculate a value for each utility in their econometric transmission cost study sample.

In the Hydro One SSM proceeding, PSE acknowledged that this variable was novel and stated that it "reflects the sophistication of Ontario benchmarking initiatives relative to other jurisdictions."[1] PSE described the loading variable as "an engineering analysis on the minimum requirements for construction for transmission assets."[2] A proper appraisal of this variable requires the expertise of both engineers and economists.

*Lack of Transparency*

Hydro One was shown to have one of the highest values of this variable in the sample, making a thorough appraisal more important.[3] However, appraisal of this complex variable was made more difficult because PSE's working papers omit many details of its development. For example, PSE did not provide the mapping data for the loading zones and the utility service territories, the PLS-CADD analysis for each loading zone in a utility's service territory, or any of the calculations underlying the loading variable. PSE also failed to provide the full documentation of the NESC Rules and CSA Standards that they relied on to ensure that no errors occurred prior to the mapping process.

*Inaccurate Value for Hydro One*

As discussed on pages 22-23 of PEG's report, PEG is concerned that the specific value for Hydro One is inaccurate. This problem arose due to an assumption PSE made in the development of this variable in that the majority of a utility's transmission infrastructure was located within its retail service territory and in equal proportions. This assumption directly conflicts with Hydro One's assertions that its retail service territory should include areas that Hydro One stands ready to serve but does not and may never provide service.[4] PSE relied on Hydro One's proposed retail service territory in the construction of this

[1] Response to SEC-29 in EB-2018-0218
[2] EB-2018-0218, Technical Conference Transcript Volume 2, p. 139, lines 18-19
[3] Response to SEC-39, p. 2 in EB-2018-0218
[4] EB-2017-0049, Transcript, Technical Conference, March 1, 2018, op. cit., p.46, line 17-p.47, line 4.

variable. Due to the lack of transparency and difficulty assigning numerous zones throughout Ontario to Hydro One, it is difficult to appraise the direction and magnitude of this error. For example, in its submission in the Hydro One Sault Ste. Marie proceeding, Staff indicated its concern that the variable was overstated.

> The CSA standards are highest in northern Ontario, where Hydro One Networks has few transmission assets and in southern Ontario, where most assets are. The location of transmission assets has no correspondence with the size of the zones on a square kilometre basis, which is the weighting variable used. OEB staff has little confidence that the value of the "hardening" variable for Hydro One Networks Transmission represents the real value. With weighting by area for significant portions of northern Ontario where there are few assets, OEB staff suspects that the "hardening" value may be overstated. This would then give a higher cost for Hydro One Networks Transmission from the estimated total cost model. If Hydro One Networks Transmission's costs are lower because its real, aggregate hardening standard is lower than the constructed value, its performance would look better based on PSE's total cost benchmarking approach.[5]

By contrast, PSE and Hydro One have indicated that the value of the variable for Hydro One is actually understated.

> However, in the SSM application, you know, we had some questions on, you know, what if you looked at where the transmission lines actually are, and so we did take a look at, you know, if you constructed that variable where Hydro One's transmission lines actually are, the variable value would go up because, you know, essentially it's my understanding the company has more assets in the southern region of Ontario rather than, you know, the middle or northern. In the southern region has the more difficult standards, climatic conditions and standards.
>
> And so if we did go to the transmission line asset approach, Hydro One's value would go up, whereas most of the other utilities in the sample would likely be unchanged just given, if you just look at the map, there's large areas where a utility would have the exact same value, so it's our belief that that would likely -- it would be favourable to the utility to do it that way.[6]

In M1-HON-7 part c, Hydro One posited that the appropriate value of the loading variable is 0.99 based on the actual location of Hydro One's transmission infrastructure, rather than the 0.86680 as reported in response to SEC-39 in EB-2018-0218.

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[5] EB-2018-0218, Staff Submission, p. 29.
[6] Technical Conference Transcript Volume 2, p. 174 lines 12-28

*Other Assumptions*

PSE relied on several assumptions in order to support its development of this variable. One is that all utilities design their transmission lines to the minimum CSA or NESC standards. As a result, the loading variable does not reflect the possibility that transmitters chose to build their assets to something higher than the minimum standards outlined by the CSA and NESC. This assumption appears to be especially dubious amongst utilities that have engaged in storm hardening.

A second assumption is that the 2011 CSA and 2017 NESC standards reflect the same differences in standards between various zones in all years, even though these standards have been periodically updated over time and transmission system build outs have likely occurred at different rates over time. This assumption appears to be problematic, given that PSE's total cost model relies on vintaged capital dating back decades. During the lengthy period where capital data are required, structural strength standards for transmission lines have been updated periodically in part to reflect changing weather during this period. A further complication is that changes in the U.S. and Canadian standards are not synchronized, resulting in potential blips in the relative standards between the U.S. transmitters and Hydro One. To the best of PEG's knowledge, transmitters are not obligated to rebuild existing lines to meet the latest standards, resulting in different vintages of capital for each transmitter being built to different structural strength standards (e.g., a line for Florida Power & Light built in 1990 was likely built to meet lower standards than that same line would be required to meet today).

PEG is especially concerned that comparisons between Hydro One and the rest of the sample do not meet PSE's assumptions. To capture the most accurate relationship between cost and structural strength standards, this variable should have been made time variant. Alternatively, PSE could have presented evidence to show that the relationship between cost and structural strength standards had not changed during the sample period for the U.S. sample or Hydro One.

A related concern is that PSE chose not to use the most recent version of the CSA standards in the development of this variable. PEG understands that the CSA standards were updated in 2015, yet PSE relied on the 2011 version of these standards to develop this variable for Hydro One. Depending on the changes made to the standards in this update, the differences in standards between zones in Ontario and the U.S. may not be the same as those reflected in PSE's model.

**M1-SEC-2**

**Reference:** Exhibit M1, Page 43

**Interrogatory:**

To what extent is it possible for the Board to use benchmarking data to create an adjustment to the C-factor that exerts downward pressure on the excessive rate of capital spending? By way of example only, is it possible to construct a capital budget envelope for the Applicant that is partly based on the Applicant's specific budget (two-thirds, for example), and partly based on the forecast growth in the benchmark capital (the other one third, in this example), and if so how would that be similar to, or different from, the Ofgem approach? What other ways are available – other than a stretch factor based on benchmarking or benchmarked budget adjustments – to use benchmarking to contain capital spending levels?

**Response to SEC-2**: The following response was provided by PEG.

The OEB's current statistical benchmarking program strengthens utility incentives to contain capital expenditures ("capex"). The X factor term of each utility's rate (or revenue) cap index typically includes a stretch factor that ranges between 0 and 0.6%, depending on the subject utility's scores in one or more econometric total cost benchmarking studies.[7] Benchmarking scores are sensitive to capex management, especially in the power transmission business inasmuch as transmission technology is unusually capital-intensive. A utility with an accelerated capital replacement program could, as a consequence of this benchmarking program, very well experience a 0.15% increase in its stretch factor over a period of five years that could stay high for many following years. This would slow revenue (or rate) cap index growth by 0.15% annually. 0.15% of the entire revenue requirement is a much larger share of the cost of new capex.

The power of statistical benchmarking to incentivize capex containment can be reduced to the extent that companies exploit provisions of OEB incentive regulation which permit them to obtain supplemental capital revenue. In 4GIRM, for instance, the advanced capital module ("ACM") and incremental capital module ("ICM") can afford utilities compensation for approved capex that exceeds a

[7] Board Staff usually commissions its own study, and the utility may also commission a study.

materiality threshold. The current materiality threshold formula has a dead zone that typically reduces eligible capex by around 5%.[8]

In Custom IR, utilities can get compensation for capital cost growth that exceeds index-driven capital revenue growth by the X factor, which is the sum of a base productivity trend and a stretch factor. The incentive power of this provision is reduced by the fact that the Board has recently chosen 0% base productivity trends. Stretch factors linked to statistical total cost benchmarking slow allowed capital growth. However, these stretch factors rarely exceed 0.3% and max out at 0.6%.

The OEB can upgrade its statistical benchmarking program and its use in rate setting to strengthen utility capex containment incentives. One way to achieve this is to bolster the impact of benchmarking results on revenue escalation. The stretch factor consistent with a poor cost performance score could, for example, be raised from 0.45% to 0.60% (or even higher). The stretch factor consistent with a bad score could be raised from 0.60% to 0.75% (or even higher).

Benchmarking could, alternatively or in addition, be used to directly establish revenue requirement levels. A company's proposed revenue requirement could, for example, be adjusted to reflect its benchmarking score. Here is a representative formula to accomplish this.

$$\text{Revenue Requirement} = \text{Proposed Revenue Requirement} \times [1 - 0.25 \times \ln(\text{Proposed Cost}/\text{Benchmarked Cost})].$$ [9]

In this example, if a company's cost was 10% above its cost benchmark,

$$\text{Revenue Requirement} = \text{Proposed Revenue Requirement} \times \{1 – [0.25 \times \ln(1.1)]\}$$

$$= \text{Proposed Revenue Requirement} \times (1-.0238)$$

$$= \text{Proposed Revenue Requirement} \times .976.$$

[8] The 10% markdown factor is higher but doesn't reduce eligible plant additions by this amount.

[9] A utility's proposed revenue requirement and the analogous proposed cost for benchmarking purposes will differ. One reason is that the latter will be calculated using a standardized capital cost treatment.

The British regulator Ofgem typically bases a utility's initial revenue requirements 75% on its own "view" and only 25% on the company's proposal. Ofgem's views on revenue requirements are developed using various tools that include statistical benchmarking, engineering models, and engineering consultants.

Total cost benchmarking can be used in both of these applications. However, since only capex is eligible for supplemental revenue, and incentives to contain capex are especially weak when supplemental revenue is requested, new benchmarking models for capital cost or capex could be developed and the results could be used in a revised ACM or C factor mechanism. PEG developed first generation capital cost and capex benchmarking models for power distributors in the recent Toronto Hydro IR proceeding.

Whether total cost, capital cost, or capex is benchmarked, a constructive focus of any modelling upgrade program would be to quantify the effect of system age on cost. Advanced system age is, after all, the chief reason why utilities seek supplemental capital revenue in Ontario. Capex could, for example, be a function of input prices (**W**), output variables (**Y**), the share of assets exceeding average service life (**AGE**), miscellaneous other business condition variables (**Z**), and a trend variable (T).

$$\text{Capex} = f(\mathbf{W}, \mathbf{Y}, \mathbf{AGE}, \mathbf{Z}, T).$$

If an unusually large share of a utility's assets are of advanced age, its capex benchmark will be higher.

**M1-SEC-3**

**Reference:** Exhibit M1, page 45

**Interrogatory:**

Please expand on the "several" arguments in favour of "making the supplemental capital cost stretch factor even higher".

**Response to SEC-3**: The following response was provided by PEG.

In their January 2016 report[10] on the materiality thresholds for ACMs and ICMs, the Board stated its latest thinking on the rationale for a dead band on capex eligible for extra revenue. A dead band of 10% balances:

> … the need for appropriately funding necessary incremental capital investments while avoiding numerous marginal applications and providing some protection that amounts are not already funded through rates.[11]

There are additional rationales for a dead band, including:

- stronger capex containment incentives
- discouragement of capex "bunching"
- helping to ensure that, in the long run, annual revenue (or rate) adjustments between rebasings pass on to customers the benefit of industry productivity growth
- sharing any benefits of retirements and OM&A cost savings that may be triggered by capex

PEG also believes that the mathematical analysis supporting the Board's current materiality threshold formula supports an alternative threshold formula. The derivation of the current formula was presented in Appendix Section B.4 of PEG's September report. Recollect that in each year *t*,

$CKD_t$ = depreciation expenses

$VKA_1^{net}$ = net plant value (aka rate base)

r = rate of return on rate base

g = billing determinant growth

I = annual price inflation

[10] *Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219), January 22, 2016.
[11] *Ibid*., p. 18.

M = markdown factor used in the Threshold Value Formula (e.g., 10%)

X = X factor term of the rate or revenue cap index = base productivity trend + stretch factor

The following relation, applicable to the first indexing year of the rate plan

$$VKA_1 > CKD_1 + VK_0^{net} \cdot [g + (I - X) \cdot (1 + g)] \qquad \text{[B14]}$$

is the basis for the materiality threshold formula

$$\frac{VKA_1}{CKD_0} > 1 + \frac{VK_0^{net}}{CKD_0} \cdot \{[g + (I - X)] \cdot (1 + g)\} + M.$$

However, the M factor can reasonably be applied directly to relation [B14], in which case the materiality threshold formula could be

$$VKA_1 > \{CKD_0 + VK_0^{net} \cdot [g + (I - X) \cdot (1 + g)]\} * (1 + M).$$

Using this approach, an *M* factor of .10 would have a markdown power closer to 10%.

[1] Note that depreciation is in the base year in the OEB's approved formula.

**M1-SEC-5**

**Reference**: Exhibit M1

**Preamble:** On pages 64-66 of PEG's evidence in EB-2018-0165 (Toronto Hydro), PEG discussed a number of issues associated with the funding of capital in custom IR.

**Interrogatory:**

Please relate those comments to PEG's proposals for capital funding in this case, and discuss why PEG's particular proposals for Hydro One were made instead of other alternatives discussed in the Toronto Hydro report.

**Response to SEC-5**: The following response was provided by PEG.

PEG's discussion, in its Hydro One Transmission report, of alternative ways to provide supplemental capital revenue is similar in most respects to the analogous discussion in their report in the recent Toronto Hydro IR proceeding. A notable exception is the following passage in the Toronto Hydro report.

> The establishment of a materiality threshold and dead zone for supplemental capital revenue in Custom IR plans has many advantages. This could be done in such a manner that the first A% of unfunded capital cost (after the X factor markdown) is ineligible for C factoring. However, the materiality threshold and dead zones need not be modelled on those in the ICMs used in 4th GIRM. For example, if proposed capital cost exceeded the materiality threshold, a set percentage of all unfunded capital cost could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capital cost at the margin. The kind of adjustment to the C factor formula that the Board approved in the Hydro One distribution IRM proceeding has less incentive impact[12].

This general idea also warrants consideration for Hydro One's transmission services.

The C factor for Hydro One's distributor services funds capital cost growth that exceeds capital revenue growth by the sum of the X factor and the S factor. Once capital cost growth exceeds X + S, there is little penalty for *incremental* growth. This encourages utilities to propose capital cost growth that far exceeds the markdown, as Hydro One has done in this case. An alternative is to mark down any amount by which capital cost growth exceeds normal capital revenue growth by a fixed percentage. One formula that would accomplish this is

$$\textit{growth Revenue}^{Capital} = I - X + [\textit{growth Cost}^{Capital} - (I - X)] * (1 - M).$$

[12] EB-2018-0165 Exhibit M1/p. 66.