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BY EMAIL AND RESS

April 19, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2021-0110 – Custom IR Application (2023-2027) for Hydro One Networks Inc. Transmission and Distribution – Clearspring Report

Further to the Ontario Energy Board's Procedural Order No. 5 dated April 14, 2022, please find enclosed Clearspring Energy Advisors' report dated March 31, 2022.

Sincerely,

Frank D'Andrea

Frank D'Andrea

Encls: Clearspring Energy Advisors Report dated March 31, 2022
cc: EB-2021-0110 parties

Responses to PEG's New Analyses and Studies

(in reply to PEG's January 2022 report)

Hydro One's Joint Rate Application

PREPARED BY:

CLEARSPRING ENERGY ADVISORS

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MARCH 31, 2022

Clearspring Energy Advisors LLC

1 PEG's New Benchmarking Analyses and Studies

PEG delivered its report dated January 12, 2022 ("PEG Report") in which PEG describes the new benchmarking analyses and studies it performed and raises certain other new issues. Clearspring was not able to consider or respond to PEG's new analyses/studies or issues in our original report dated July 30, 2021 since the new analyses/studies and issues were only disclosed in the subsequent PEG Report. In the sections below we respond to PEG's new analyses/studies and recommendations, and its new issues, by noting and briefly outlining the main areas of disagreement Clearspring has with them. We are doing so in order to facilitate conferring with PEG in an effective and efficient way under rule 13A.04 of the OEB's Rules of Practice (by identifying areas for discussion in respect of PEG's new studies and points), and to provide intervenors with disclosure of Clearspring's responding points.

1.1 PEG's New Transmission Cost Benchmarking

While PEG and Clearspring agree that the transmission X-factor for Hydro One should be at or near zero, there are three consequential concerns Clearspring has regarding PEG's new transmission total cost benchmarking methodology. These are: 1) a mistake (acknowledged by PEG) in the application of ratcheted peak demand; 2) exclusion of an ISO variable such that PEG's model is unadjusted for a business condition which PEG has recognized in its report and included in previous research; and 3) exclusion of six utilities from the transmission sample instead of simply excluding problematic cost categories (as PEG has done in the past).

PEG used a ratcheted transmission peak demand variable in its transmission cost models. A ratcheted demand variable uses the maximum annual peak demand from either the current year or prior sampled years for each utility.[1] The variable value cannot, by definition, decrease over time for a given utility. PEG calculated the ratcheted peak for all sampled utilities except for Hydro One. It used a peak demand variable that was not ratcheted for Hydro One. This produced a substantially lower transmission peak demand variable for Hydro One, disadvantaging the Company in PEG's transmission benchmarking results. PEG has now acknowledged this mistake in its interrogatory responses and provided corrected results for Hydro One which resulted in a significant improvement in Hydro One's benchmark score of approximately 13% to a +1% benchmark score during the CIR period. This correction and resultant score correspond with a 0.3% stretch factor.[2] We note, though, that PEG has not revised its report to reflect this correction.

PEG did not include in its transmission cost models a business condition variable that accounts for ISO/RTO membership, even though the PEG Report lists the Company's ISO membership as one of the business conditions that Hydro One faces.[3] All of the other listed business conditions are included as variables in PEG's transmission total cost model. By contrast, PEG did include an ISO variable in its transmission cost research in its recent work in Québec. PEG and Clearspring, therefore, have recognized that ISO membership is a business condition variable that influences cost levels. The variable displays a high level

[1] The ratcheted peak demand value will be the higher of any historical annual peaks or the current peak.

[2] Please see PEG's interrogatory response in Exhibit N, Tab 1, Schedule 16, part b.

[3] P. 34 of the PEG Report.

of statistical significance at the 99.9% confidence level in both the Clearspring model and PEG's Québec model.[4] PEG stated: "PEG acknowledges that the costs of some transmitters may have increased on balance as a result of ISO membership."[5]

PEG seeks to defend this omission in its model by saying ISO members are more likely to serve areas with high input prices and urban congestion. However, input prices are already adjusted for in the cost models and urban congestion is far less of an issue for transmission than it is for distribution. Furthermore, Hydro One's transmission system serves urbanized cities such as Toronto and Ottawa.[6] PEG's omission of this statistically significant variable provides no adjustment of this known and recognized business condition for Hydro One in its model. If PEG did include an ISO variable, the variable would be highly statistically significant and Hydro One's transmission benchmark score would improve by approximately 12%, and result in a score of -11% (taking into account both the peak demand correction and this inclusion).[7]

Finally, PEG excluded six transmission utilities from the transmission sample based on what PEG believed to be implausible OM&A cost levels in the categories of miscellaneous transmission and dispatching expenses.[8] PEG states in an interrogatory response that it used no formal threshold in making these exclusion decisions but rather depended upon its judgement.[9] However, PEG did include these same six utilities in its Hydro-Québec MFP trend research used to support its productivity factor recommendation of -0.62%. PEG also included these utilities in its benchmark and TFP sample in the last Hydro One transmission application (EB-2019-0082).[10]

The researcher must be cautious in making such exclusions so as to not create a sample bias in the dataset. This is a concern in respect of PEG's dataset as the six excluded utilities all had poor cost performance scores throughout the sample period. In fact, the six utilities averaged a benchmark score of +43% during the sample period, the best utility having a score of +22% and the worst having a score of +73%. Further, there are four specific concerns Clearspring has with PEG's methodology shift:

1. **The sample exclusions are inconsistently applied with no objective criteria.** There are large increases and decreases in the cost categories of miscellaneous and dispatching expenses throughout the dataset for several utilities, not just the six excluded utilities. For example, eleven

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[4] In Clearspring's model, the ISO variable is highly statistically significant with a p-value of 0.000. In PEG's Québec model, the variable is also highly statistically significant with a reported p-value of 0.000.
[5] Exhibit N, Tab 1, Schedule 3, part g.
[6] Please see PEG's response in Exhibit N, Tab 1, Schedule 15, part c. PEG makes two other points, one is conjecture that says Hydro One's cost pressures may differ from other U.S. ISO members. This is true, they may be higher or lower but without evidence benchmarking assumes the peer group is representative of the target utility. The last point is not relevant as to why PEG did not include an ISO variable in its model as PEG points to Clearspring's sample data having data idiosyncrasies which PEG claims to have remedied in its dataset.
[7] Please see PEG's interrogatory response in Exhibit N, Tab 1, Schedule 15, part d.
[8] The six excluded utilities are Commonwealth Edison, Southern California Edison, Oklahoma Gas and Electric, Kansas Gas and Electric, San Diego Gas & Electric, and PECO.
[9] Exhibit N, Tab 1, Schedule 13, d.
[10] In those proceedings, rather than excluding six utilities from the sample, PEG simply excluded the problematic cost categories from the cost definitions -- Exhibit N, Tab 1, Schedule 3, part c.

utilities that PEG left in the sample have miscellaneous plus dispatching expenses that are greater than 50% of their OM&A expenses for one or more years.[11] The six excluded companies have several years below that 50% threshold. If PEG believes these six utilities reported implausibly large values for these cost categories, then other utilities that are included in PEG's dataset would also have implausible values.

2. **PEG could have simply excluded the years with the questionable data.** For two of the excluded utilities (Southern California Edison and San Diego Gas & Electric), the cost categories in question moved above 50% of OM&A but then returned to much lower levels in recent years to around 20% of OM&A in 2017 to 2019. In fact, 31 out of the 51 utilities left in PEG's sample had percentages of miscellaneous and dispatching expenses in OM&A higher than these two utilities in the last three years of the sample. Ten utilities left in the sample by PEG averaged over 40% in these categories and three averaged over 50%.[12] Rather than excluding all years for these two utilities, only the years where PEG viewed that cost levels were implausibly high could have been excluded. This would have preserved two utilities in an already limited sample and lessened, although not eliminated, the risk of sample bias.

3. **It is not clear that accounting problems due to ISO membership are occurring.** Only two of the six excluded utilities saw large increases in the dispatching and/or miscellaneous cost categories in the year they joined an ISO.[13] Two utilities incurred large increases in these cost categories well before joining an ISO.[14] Two other utilities saw their increases occur after ISO membership.[15] Thus, fluctuations in these expense categories are not necessarily tied to accounting problems due to ISO membership. The expense increases may be legitimate expenses of transmission activities, perhaps driven by ISO membership, that are accounted for properly and reflective of activities that are also included in Hydro One's cost definitions.[16]

4. **PEG's approach of excluding the six utilities reduces the sample size and the availability of degrees of freedom.** PEG removed over 10% of the sample. If they had applied the same exclusion criteria to the entire sample of these categories being at or above 50% of OM&A expenses, over 25% of the sample would need to be eliminated. PEG recognized the possible harm

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[11] Some of these included utilities had large jumps when they joined an ISO. Other utilities had jumps even though they are not members of an ISO or at a time that does not correspond with ISO membership.

[12] In the last three years of the sample, Southern California Edison and San Diego Gas & Electric had miscellaneous transmission and dispatching expenses of 20.8% and 18.6%, respectively. This is close to Hydro One's expense levels in those categories.

[13] These two are Commonwealth Edison and Southern California Edison.

[14] Oklahoma Gas and Electric saw a large increase in these cost categories 4 years prior to joining an ISO. Kansas Gas and Electric saw large increases 12 years prior to joining.

[15] San Diego Gas & Electric did not have an increase in the miscellaneous and dispatching cost categories until the year after ISO membership. PECO incurred increases two years after membership.

[16] In 2016 Hydro One incurred $53.8 million in miscellaneous and dispatching expenses. This is 18% of Hydro One's OM&A expenses. In 2019, this number was $38.5 million or 13% of OM&A.

to the transmission sample resulting from exclusions, as it noted that the transmission sample is considerably smaller than the distribution sample, and therefore deemed it preferable to revise some transmission peak load data for certain utilities rather than exclude them from the sample.[17] Excluding the six utilities on a subjective basis harms the information and degrees of freedom available to the model.

If PEG continues to believe dispatching and miscellaneous expenses improperly distort the OM&A cost data for the sample, then PEG should subtract those expenses from the cost definition and retain these utilities in the sample -- an approach that would not bias or severely limit the sample. PEG in fact took this approach in the last Hydro One Transmission application and its Hydro Québec MFP research, on which it continues to rely in support of its productivity factor recommendation in this application. In taking this approach, an estimate should be made of the corresponding Hydro One expenses, and those expense categories should also be excluded for Hydro One to ensure a consistent cost definition.[18] [19] [20]

If PEG were to make the above corrections or improvements to its model: 1) ratchet peak demand for Hydro One as done with the rest of the sample, 2) include the statistically significant ISO variable such that PEG's model is adjusted for this business condition which PEG has recognized and included in its previous research; and 3) re-include the six excluded utilities and subtract the problematic cost categories as PEG did in the prior Hydro One transmission proceeding and in the Hydro Québec MFP research being used now to support PEG's productivity factor, with no other changes, Hydro One's transmission total cost benchmark score during the CIR period becomes -27% under PEG's model.

Corrections/Improvements	PEG's Benchmark Score for Hydro One
PEG Originally Reported Result	+14%
Ratchet Peak Demand for Hydro One as done for rest of peer group	+1%
Add ISO Business Condition Variable and Ratchet Peak Demand for Hydro One as done for rest of peer group	-11%
Re-include excluded utilities and Exclude Misc. and Dispatching Expenses, add ISO Variable, and Ratchet Peak Demand for Hydro One as done for rest of peer group	-27%

[17] Exhibit N, Tab 1, Schedule 16, part d.

[18] PEG could have requested estimates of those cost categories from Hydro One during the interrogatory process.

[19] While PEG did subtract out expense categories for the U.S. sample in the prior transmission application, they left those expenses in for Hydro One. This created an inconsistent cost definition.

[20] If we subtract out miscellaneous transmission and dispatching expenses from the cost definition and use Hydro One's 2019 estimate of 12.6% of those expenses in OM&A for all years, PEG's result for Hydro One's transmission total costs would improve by approximately 20%.

This revised benchmarking result under PEG's model would indicate a stretch factor recommendation of 0.0% and a transmission X-factor at or less than 0.0% -- consistent with Clearspring's study results and recommendations.

1.2 PEG's New Distribution Cost Benchmarking

The main driver of the differences between PEG's new distribution cost benchmarking and Clearspring's is the output variable used to measure density or what PEG calls the dispersion challenge variable. Rather than use the distribution service territory as an output variable, PEG instead used transmission line miles into its new distribution cost models -- a surprising choice in a study of Hydro One's distribution costs. PEG has never before used transmission line miles as a variable in a distribution model in its econometric benchmarking research[21] (nor have Clearspring or Mr. Fenrick).

PEG states on p. 49 of its report that transmission line miles should be "highly correlated" with distribution service territory. While service territory and transmission line miles will be correlated in the sample, that does not mean that transmission line miles is a driver of distribution total costs -- as it clearly is not -- nor that it is a proper choice for a distribution benchmarking study of Hydro One. To the extent the ratio of Hydro One's transmission line miles to the sample does not closely correspond with the ratio of Hydro One's service area to the sample, the benchmark score for Hydro One will be unreliable and inaccurate.

Hydro One's transmission line miles are reported by PEG on p. 48 of its report to be 3.89 times the sample mean. Given the mean scaling of variables, this means that Hydro One's density output variable value is 3.89 while the mean of the sample is 1.00. PEG's density output (or dispersion challenge) variable value in its model is therefore 3.89 for Hydro One due to the mean-scaling procedure. On that same page, PEG reports that Clearspring's distribution service area variable is 30.71 times the sample mean. PEG asserts that "the Company's transmission line length was a more plausible 3.89 times the mean." However, the service area assumption Clearspring used in its research (651,974 square kilometres) is the exact value used by PEG in EB-2019-0261 for Hydro One in the Hydro Ottawa proceeding when it used distribution service area in its distribution total cost benchmarking research.

Straightforward math shows that the distribution service area of the U.S. sample has a mean of 21,230 square kilometres.[22] For transmission line miles to be a reasonable estimate of distribution service area

[21] Exhibit N, Tab 1, Schedule 21, part b.

[22] 651,974 divided by 30.71 equals 21,230.

for Hydro One and to be highly correlated in relation to Hydro One implies that Hydro One's service area would need to be around 82,585 square kilometres (calculated by multiplying 21,230 by 3.89).[23]

Is 82,585 square kilometers an accurate or approximate estimate of Hydro One's service territory? Not in our view, and if not, then PEG's benchmark score is based on a variable that has little to no connection to distribution costs for Hydro One itself and, thus, PEG's benchmark results would not be reliable.

Southern Ontario alone has a size of approximately 140,000 square kilometres. The rest of the LDCs serving Ontario have a 2019 RRR reported service area of approximately 30,000 square kilometres. This implies that Hydro One serves approximately 110,000 square kilometers in southern Ontario. Using the 82,585 square kilometers implies that 25% of Southern Ontario is not served by any utility and none of northern Ontario is electrified at all. This clearly is not the case and shows that PEG's use of 3.89 as the density output or dispersion challenge variable for Hydro One severely undervalues the challenges of Hydro One's service territory.

On this point, Hydro One has provided Clearspring with a map which provides an estimate of Hydro One service area based on areas where Hydro One has distribution stations within a given radius.[24] This map is attached in the Appendix to this report. While there are large portions of northern Ontario that do not have access to grid electricity, the area where the Company does offer electric service is many times larger than 82,585 square kilometers. The estimate of service area found in the Appendix is approximately 530,000 square kilometres.[25] If this area estimate were used, Hydro One's mean-scaled density or dispersion challenge variable value would have a value of 24.96. This is 6.4 times larger than PEG's transmission line length derived mean-scaled output variable value of 3.89. Clearspring understands that Hydro One's full licensed service area is around 960,000 square kilometers. The area used by Clearspring in its study (which is 651,974 square kilometres and was taken from PEG's research in the recent Hydro Ottawa proceeding) therefore reduced Hydro One's licenced service area by over 300,000 square kilometers. This area estimate provides sufficient credit for the expansiveness and challenges of serving such a vast and spread-out area. While there are some unserved areas in that estimate, the U.S. sample distribution area values also include some unserved areas.[26]

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23 $$Hydro\ One's\ Tx\ Line\ Mile\ to\ Sample\ Ratio = \frac{20{,}783\ HON\ Tx\ miles}{5{,}347\ Sample\ Tx\ miles} = 3.89$$

$$Implied\ Hydro\ One\ Distribution\ Area\ to\ Sample\ Ratio = \frac{\boldsymbol{X}}{21{,}230\ Sample\ Sq.KM} = 3.89$$

Solving for X above equals 82,585 square kilometers. This produces the same ratio for Hydro One to the sample as transmission line lengths produces.

24 For high voltage substations, Hydro One used a radius of 100 kilometers. For lower voltage substations the radius was 65 km.

25 The exact estimate provided by Hydro One is 529,313 km.

26 PEG agrees with this statement in Exhibit N, Tab 1, Schedule 21, part c.

Clearspring acknowledges that finding an accurate estimate of distribution service area for Hydro One can be challenging. However, without a reasonable variable adjusting for service area, an enormous cost driver and cost challenge for the Company is not being properly accounted for. The cost challenge includes both building and maintaining assets within that territory and covering the large distances between operation centers and those assets. Given the above estimate of 530,000 square kilometers of service territory, we re-estimated the Clearspring distribution total cost model with no other changes except modifying the density output variable value to 530,000. We also estimated PEG's distribution total cost model result if it used distribution service area as the output variable instead of transmission line miles and the 530,000 square kilometer estimate. The results are provided in the table below.

Distribution Total Cost Model	Hydro One Benchmark Score for CIR Period Using 530,000
Clearspring	**10.9%**
PEG	**13.9%**

Clearspring also ran PEG's new distribution total cost model and included both transmission line miles <u>and</u> distribution service area as output variables, including quadratic and interaction terms for both. When area and transmission line miles are both included as output variables, the transmission line miles first order coefficient becomes wrongly signed as a negative coefficient rather than the expected positive.[27] Distribution area is correctly signed and statistically significant. Hydro One's distribution benchmark score in PEG's model after adding service territory (and leaving in transmission line miles) is +13%.[28] Distribution area appears to dominate transmission line miles when both are included in PEG's model, which is an expected result given this is a distribution cost model and not a transmission cost model.

If the above 530,000 square kilometre distribution service area estimate were used in both Clearspring's and PEG's models, this would result in both the Clearspring model benchmark score and the PEG model score being in the 0.45% stretch factor cohort. This may be one of the points that would benefit from conferring with PEG. We also note that PEG stated in an interrogatory response that if the OEB prefers distribution service area to transmission line miles in a distribution cost model, then PEG recommends using scores that imply a 0.45% distribution stretch factor rather than its originally reported results.[29] Additionally, using transmission line miles requires eliminating eleven utilities from PEG's sample, many

[27] A negative first order coefficient implies that at the data mean an increase in transmission line miles will lower total costs. This is clearly the wrong sign and indicates transmission line miles should be excluded from the model.
[28] This is using the 530,000 square kilometer estimate discussed above.
[29] Revised comments by PEG in Exhibit N, Tab 1, Schedule 21, part d.

of which serve rural forested areas in the northern U.S. somewhat similarly to Hydro One, which further harms the accuracy of PEG's reported results.[30]

2 PEG's New Transmission MFP Research

Clearspring has no consequential concerns with PEG's MFP research other than PEG's use of the longer period of 1996-2019 as its preferred MFP trend period as the basis for PEG's recommendation of a -0.62% productivity factor. Clearspring's TFP trend estimate of -1.66% uses the years 2000 to 2019, a 19-year trend. Given that transmission productivity has been more negative in recent years (in the last ten years it has been around -2.8%), we view using a 19-year period as being conservative. The cost challenges have increased dramatically from the 1990s and early 2000s and productivity expectations have slowed considerably.

PEG states that they are unsure if Hydro One will encounter similar productivity growth challenges as those faced by its peers.[31] PEG is uncertain if the Company's challenges will be less than, equal to, or greater than its peers.[32] Without evidence to the contrary, benchmarking and industry TFP trends assume that companies in the same industry and facing the same or similar regulations and cost pressures will have similar cost and productivity challenges.

We also, however, have some evidence suggesting that Hydro One Transmission's productivity growth challenges will be higher than that of the sample. Clearspring's capital age research demonstrated that Hydro One's transmission assets are considerably older than those of the U.S. sample. While this older capital age helps explain why Hydro One performs well in the Clearspring transmission total cost benchmarking study, it does present the Company with productivity challenges in the CIR period that are above and beyond those faced by its peers with younger capital ages. Based on the capital age evidence, it seems likely that Hydro One will be faced with equal or more productivity growth challenges as that of the sample.

We agree with PEG that the X-factor needs to account for the negative productivity growth found in the transmission industry for it to be compensatory and align with cost theory and indexing logic. PEG recommends an X-factor of 0.13% for transmission before making any adjustments to its transmission total cost results. This implies that PEG's effective stretch factor under the scenario of a productivity factor of 0.0% is essentially 0.0%, the same as Clearspring's recommendation of 0.0%. Both PEG and Clearspring

[30] PEG states in its revised statements in Exhibit N, Tab 1, Schedule 21, part d, "Another disadvantage of using transmission lines is that more than a few companies must be excluded from the econometric calculations. This is most commonly due to the fact that these companies don't provide transmission service. Many of these companies (e.g., Consumers Energy and Wisconsin Electric Power) serve forested rural areas of the northern U.S. and would thus be desirable additions to the econometric sample."
[31] See p. 8 of the PEG report.
[32] Exhibit N, Tab 1, Schedule 2, part b.

agree that a stretch factor of 0.0% combined with a productivity factor of 0.0% still contains a significant implicit stretch factor.[33] [34]

3 Other New Issues Raised by PEG Regarding Clearspring's Benchmarking Approach

In the PEG Report, it raised some other new issues regarding Clearspring's transmission cost benchmarking research (not touched on above), to which we briefly reply as follows.

- PEG states that Clearspring based its peak demand variable on the monthly peak demand data instead of transmission peak demand. PEG acknowledges that we needed to use monthly peak demand to have an earlier start date. Clearspring used transmission peak demand in the last transmission proceeding and began its econometric benchmarking dataset in 2004. PEG at that time criticized us saying, "The relatively short sample period of the econometric work unnecessarily reduces the precision of the econometric model parameter estimates." [35] If Clearspring used the transmission peak demand data and used the shorter sample period now used by PEG that begins in 2004, the result is that Hydro One's transmission total cost performance during the CIR period is -26%, as opposed to Clearspring's calculated value of -34%.

- PEG states it believes it is more appropriate to ratchet the peak demand than take a rolling average. While we disagree with PEG's view on this point, if Clearspring used the ratcheted peak demand variable in its model, with no other changes, the transmission benchmark score during the CIR period improves for Hydro One and continues to be in the 0.0% stretch factor cohort.

- PEG says that, in its view, Clearspring's transmission substation data are inaccurate. PEG has a valid point in its description of the substation data and how to count substations. Clearspring counted all rows as individual substations, whereas PEG examined the addresses and noticed those with the same address should not be counted multiple times but the utility only given credit for one substation. We appreciate PEG's work in this area as there are literally thousands of pages of substation data to sort through and examine with utilities reporting substation data in different manners and differently in different years. PEG provided an updated substation estimate in its dataset and using either the Clearspring data or the PEG data makes no material difference in the benchmark score of Hydro One.[36]

- PEG said that it has a concern that Clearspring did not include the construction standards index as an explanatory variable in its model, whereas we did include the variable in the last

[33] Additionally the Company's proposed supplemental stretch factor of 0.15% on capital further challenges the Company.
[34] Exhibit N, Tab 1, Schedule 5, part e.
[35] Please see p. 22 of PEG's report in EB-2019-0082.
[36] Exhibit N, Tab 1, Schedule 15, part e.

transmission proceeding. We chose not to include the variable due to concerns that PEG and other intervenors had in the last proceeding. PEG stated on p. 22 of its report in the prior proceeding regarding the variable, "Moreover, the accuracy of the calculation of the value for Hydro One is critically important, and we believe that PSE misstated Hydro One's value." PEG has now used that same variable value it said was misstated. The value is based on Hydro One's full licensed service territory. In the distribution modeling work, PEG does not believe that the full licensed service area is the right measure for Hydro One. PEG should have instead increased the value for Hydro One to 0.99 which is the value of the construction standards in areas where Hydro One has transmission lines. The presence of this variable in Clearspring's model would improve Hydro One's benchmark score.

- PEG says that Clearspring should have used a scope economy variable that netted out general gross plant value. We agree, especially since Hydro One's variable value included an allocated portion of general plant in the numerator whereas the U.S. utility sample did not. If we net out the general plant from the scope variable for the U.S. sample, Hydro One's transmission total cost result becomes -29% during the CIR period. This is about 5% higher yet does not modify our stretch factor recommendation.

- PEG says that Clearspring's ISO variable is bolstered by the idiosyncratically reported OM&A cost category expenses that we discussed in section 1. We demonstrated that PEG's result is not driven by these cost categories but rather the exclusion of six poor cost performers. When the cost categories at issue are subtracted out of the cost definition for all utilities (as was PEG's approach during the last Hydro One transmission proceeding and its Hydro Québec transmission MFP research) and PEG includes an ISO variable (which is highly statistically significant if included in PEG's model even after excluding the problematic cost categories) along with correcting its peak demand variable, its result is very close to Clearspring's result after we fix the netting out of general plant issue. PEG's result is -27% and ours is -29% during the CIR period.

In the PEG Report, it raised some other new issues regarding our distribution cost benchmarking research (not touched on above), to which we briefly reply as follows.

- PEG agreed that Clearspring's "distribution work" variable is worthwhile but said the variable we used was not appropriate. PEG gave no reason for its view. Clearspring's distribution model uses this variable to adjust for the differences in the subtransmission work a distributor needs to undertake.

- PEG cites the same scope variable concern as mentioned in transmission, however, Clearspring did not include a scope variable based on the percentage of distribution plant in our distribution cost model (recall we used the same exact specification as PEG used in Hydro Ottawa for the distribution model). The scope variable that is included is a measure of the percentage of electric customers to total electric and gas customers. As such, we believe PEG may have confused our distribution with our transmission model when citing this as a concern.

- PEG states in Exhibit N, Tab 5, Schedule 13 that Clearspring's capital age variable was constructive but not conclusive. PEG says inconclusive because our capital age variable focuses on average capital age rather than a measure of the proportion of end-of-life assets. However, the average capital age is certainly of large importance in determining a utility's total cost amounts and levels. All else equal, a utility with an older capital age will have lower capital costs and, thus, a better benchmark score. Clearspring's capital age results, therefore, support Clearspring's benchmark results and also serve to substantiate the corrections suggested to PEG's transmission and distribution models.

4 Concluding Remarks

PEG's methodology in its new benchmarking analyses/studies contained a few consequential errors that materially impacted the benchmark scores for both transmission and distribution. When those issues are remedied, the results of PEG's new studies would be similar to those of Clearspring. The concerns that PEG had regarding Clearspring's total cost benchmarking research have been addressed with one correction needed on the transmission total cost result moving our CIR result to -29% from -34% but not changing our recommended stretch factor and X-factor of 0.0%.

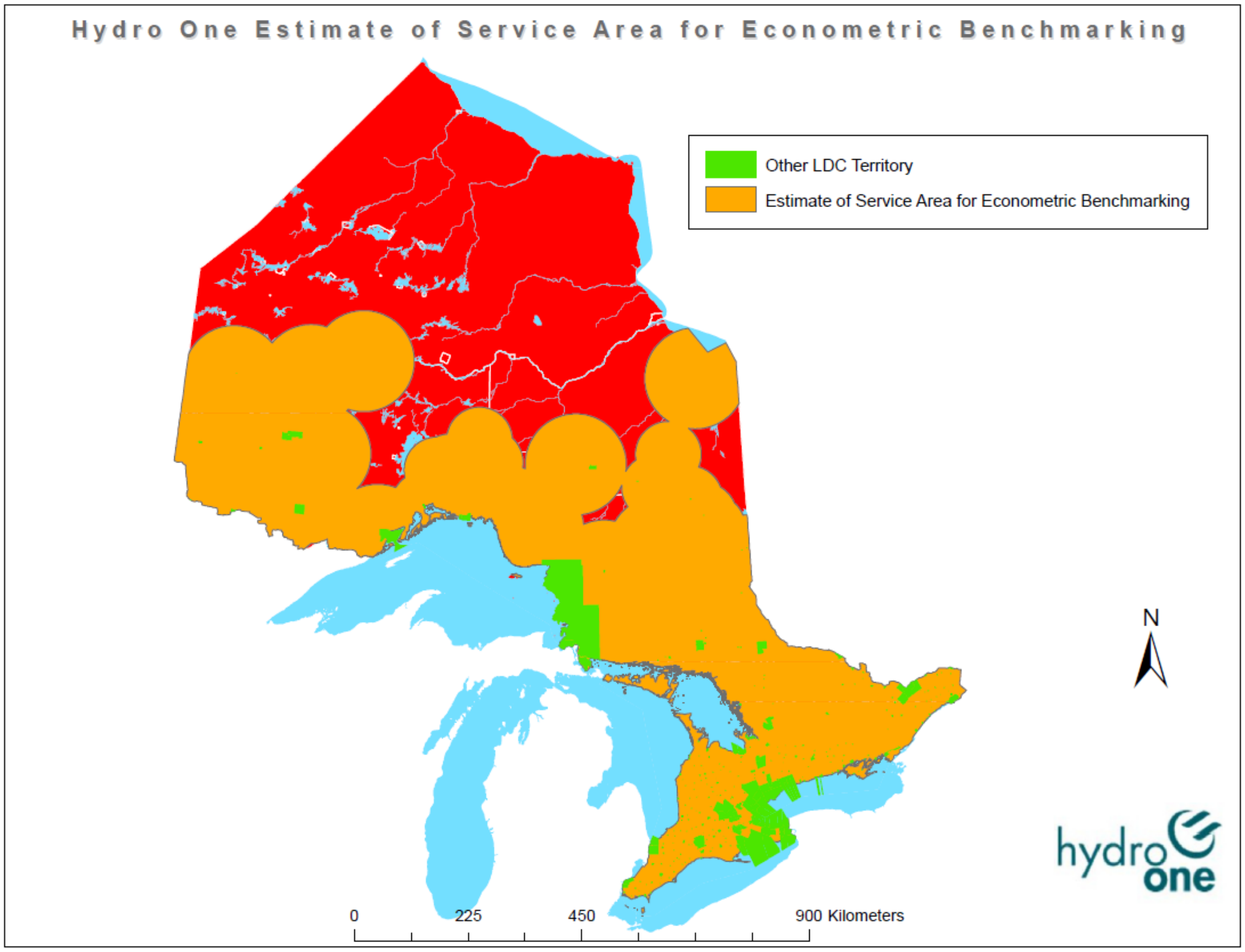
If PEG were to make any of the corrections noted in section 1.1 above in respect of its transmission total cost benchmarking, the implied transmission X-factor recommendation from PEG becomes negative. Clearspring is of the view that a transmission X-factor no higher than 0.0% is appropriate and still includes a very sizeable and challenging implicit stretch factor.

In respect of the distribution benchmarking results, PEG stated in its interrogatory response that if the OEB prefers distribution service area to transmission line miles, PEG recommends using scores that imply a 0.45% distribution stretch factor.[37] While we view the Clearspring results implying a 0.3% distribution stretch factor as reasonable, we recognize that using a lower value of distribution area for Hydro One may have some merit and would imply a 0.45% stretch factor.

[37] Revised comments by PEG in Exhibit N, Tab 1, Schedule 21, part d.

Appendix - Estimate of Service Area for Econometric Benchmarking

The map attached provides the service territory used to estimate the distribution area of 530,000 square kilometers. The orange-colored portion is approximately 530,000 square kilometers and is based on the service areas where Hydro One has distribution stations within a given radius.[38] This number subtracts out the service territories of the other LDCs (colored in green).[39]



[38] For high voltage distribution substations, Hydro One used a radius of 100 kilometers. For lower voltage substations the radius was 65 km.

[39] Five Hydro One Remotes communities fall within the orange-coloured portion but the area of these Remotes communities (Hillsport, Oba, Sultan, Biscotasing, and Pikangikum) is not material.