Incentive Regulation for Hydro One Transmission

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1. Introduction and Summary

1.1. Introduction

Hydro One Networks ("Hydro One" or "the Company") proposed Custom Incentive Rate-Setting ("IR") for the bulk of its power transmission services in a March 2019 application.[1] The Ontario Energy Board (the "Board" or "OEB") has already approved an IR plan for a smaller affiliated transmission utility, Hydro One Sault Ste. Marie ("Hydro One SSM").[2] The proposed plan is similar to that which the Board recently approved for Hydro One's distributor services.[3] Escalation of a revenue cap index ("RCI") would be slowed by a Productivity (aka "X") Factor.

The proposed X factor is supported by transmission productivity and cost benchmarking research[4] by Power System Engineering, Inc. ("PSE"), a Madison, Wisconsin consulting firm. Steven Fenrick and Eric Sonju authored PSE's report.[5] PSE's report details an update to the productivity and benchmarking study PSE prepared for the Hydro One SSM IR proceeding. The revised study corrects for several errors identified in that proceeding and considers new cost projections that reflect Hydro One's latest Transmission Business Plan.

Hydro One's Custom IR evidence merits careful examination in this proceeding for reasons that include the following:

- The Company's transmission business accounts for a not immaterial portion of the rate-regulated charges of Ontario electric utilities, especially to industrial ratepayers.
- The OEB has long expressed an interest in extending IR to power transmission.

[1] EB-2019-0082.

[2] Ontario Energy Board, EB-2018-0218, Decision and Order, Hydro One Sault Ste. Marie LP, June 20, 2019. Hydro One SSM provides transmission services in a region east of Lake Superior. The company was created after the acquisition of Great Lakes Power Transmission Inc. in 2016 by Hydro One, Inc. It is now being integrated into the larger transmission operations of Hydro One Networks Inc., but its revenue requirement is still separately regulated.

[3] Ontario Energy Board, EB-2017-0049, Decision and Order, Hydro One Networks Inc., March 7, 2019.

[4] Exhibit A/Tab 4/Schedule 1/Attachment 1.

[5] Mr. Sonju is the President of PSE. Mr. Fenrick, a former employee of PEG, recently left PSE and is now a Principal Consultant and Partner of Clearspring Energy Advisors in Madison.

- No "top down" statistical benchmarking study of Hydro One's transmission cost has yet been fully vetted (i.e., including expert testimony in an oral hearing) in an OEB proceeding. Neither has a study been fully vetted on the transmission productivity trends of Hydro One or peer utilities.

Pacific Economics Group Research LLC ("PEG") is North America's leading energy utility productivity and statistical benchmarking consultancy. We have done several power transmission productivity and benchmarking studies, and recently played a key role in the development of IR for transmission services of Hydro-Québec. OEB staff retained PEG in Hydro One SSM's IR proceeding to critique PSE's evidence and prepare an alternative study and evidence. We have been asked to consider PSE's new evidence and the Company's IR proposal in this proceeding and to revise our study and evidence.

This is our report on this work. It is, in essence, an update of the evidence[6] we filed in the Hydro One SSM proceeding which takes into account PSE's new evidence, the OEB's recent IR decisions on Hydro One distribution[7] and Hydro One SSM, as well as evidence PEG filed in the current Toronto Hydro IR proceeding.[8] The following are the key areas where we update and upgrade our evidence from the Hydro One SSM case:

- We have revised our research methods in a few ways that include a better econometric cost model estimation procedure and Canadian asset price index. Further discussion of changes in our research methods since the Hydro One SSM proceeding can be found in Appendix Section B.3.
- We propose a supplemental stretch factor for determining the C factor and calibrate it to produce a markdown similar to that in the materiality threshold for incremental and advanced capital modules ("ICMs/ACMs") in the fourth generation incentive regulation mechanism ("4GIRM").
- Commentary on several topics has been expanded or refined.

[6] EB-2018-0218, Exhibit M1.

[7] EB-2017-0049, Decision and Order, March 7, 2019.

[8] EB-2018-0165, Exhibit M1 (Updated), May 22, 2019 and Undertaking J10.5 filed July 26, 2019.

Following a brief summary of our findings, Section 2 provides pertinent background information. Section 3 provides our critique of PSE's new research and testimony. Section 4 discusses new productivity and benchmarking results by PEG using better methods and new data. We provide in Section 5 our stretch factor and X factor recommendations for Hydro One's transmission services. Appendix A of the report discusses at a high level the use of index research in the design of a revenue cap index. Appendix B discusses various methodological topics in the report in more detail, while Appendix C discusses U.S. regulation of power transmission. A brief discussion of PEG's credentials is provided in Appendix D.

1.2. Summary

Empirical Issues

PSE developed an econometric model of total power transmission cost using operating data for Hydro One and 56 U.S. utilities over the 2004-2016 period. This model was used to benchmark Hydro One's transmission cost over the same historical period, as well as the Company's forecasted/proposed cost for the 2020-2022 period, during which it would operate under its proposed plan of rebasing in 2020 and a revenue cap for 2021 and 2022. PSE also calculated the multifactor productivity ("MFP") growth of 47 U.S. utilities and Hydro One in the provision of transmission services from 2005 to 2016. Hydro One's transmission productivity growth was calculated from 2005 to 2022.

U.S. Transmission Productivity

The sampled U.S. transmitters averaged a 1.45% annual MFP decline over PSE's full 2005-2016 sample period. Productivity in the use of operation, maintenance, and administration ("OM&A") inputs averaged a 1.11% annual decline while capital productivity averaged a 1.48% decline. PSE nevertheless recommends a 0.00% base productivity trend for the revenue cap index, and Hydro One embraced this proposal. The 1.45% difference between zero and the calculated transmitter MFP trend is portrayed as an implicit stretch factor.

Our review of PSE's research raised concerns about its calculations of U.S. transmission productivity. Here are our main concerns.

- The 2005-2016 sample period was one during which U.S. power transmission productivity was adversely influenced by special circumstances that included the Energy Policy Act of 2005. The Federal Energy Regulatory Commission ("FERC") was authorized to oversee reliability standards. Incentives to contain cost were weakened by special investment incentives and by formula rate plans administered by the FERC under which a growing number of transmitters operated. Some transmitters made investments to access remote renewable resources and improve the functioning of bulk power markets. Absent information that Hydro One will somehow face comparable cost pressures in the next few years, we believe that a longer sample period is desirable in a study intended to inform selection of its base productivity growth trend.

- PSE's treatment of OM&A expenses doesn't handle structural change in the U.S. transmission industry well. Many sampled utilities have joined independent transmission system operators ("ISOs") or regional transmission organizations ("RTOs"), and this materially affected the reported OM&A expenses of some companies. Exclusion from our calculations of costs that were especially sensitive to this restructuring is appropriate for benchmarking and X factor calibration research.

- The calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate. For example, the initial or benchmark year for the calculations was 1989 for U.S. utilities whereas a benchmark year of 1964 is possible, and is preferable in our view.

These and other concerns prompted us to develop our own power transmission productivity study using better methods and data for Hydro One and the same group of U.S. utilities over the longer 1996-2016 sample period. We found that the transmission MFP of sampled utilities averaged a 1.47% annual decline over the 2005-2016 sample period chosen by PSE but only a 0.25% decline over the full sample period. OM&A productivity growth averaged -1.64% over the shorter sample period but -0.69% over the full period. Capital productivity growth averaged -1.45% over the shorter period but -0.19% over the full period. Our estimates of transmitter output do not reflect any possible improvements in U.S. transmission reliability or bulk power market performance which may have occurred during this period.

Hydro One's Transmission Cost and Productivity Performance

PSE reports that the total transmission cost of Hydro One was a substantial 21.8% below its econometric cost model's prediction over the three most recent historical years for which data were available (2014-2016). The Company's forecasted/proposed total cost is 27.1% below the model's predictions during the years of the proposed IRM (2021-2022).

PSE reports that the transmission productivity growth trend of Hydro One was considerably better than that of its U.S. peers during the 2005-2016 historical period. The Company's annual MFP growth averaged a 0.18% annual decline. During the 2021-2022 period of the proposed IR plan, however, PSE reports that the forecasted/proposed total transmission cost of Hydro One would reflect a 1.70% average annual MFP decline that is more in line with its estimate of the recent U.S. trend.

Our chief concerns about PSE's assessment of Hydro One's transmission performance include the following:

- Capital cost data are available for Hydro One only since 2002, and this reduces the accuracy of capital cost and MFP calculations (whether made by PSE or PEG) which are based on these data.
- PSE's calculation of capital costs of the sampled U.S. transmitters was unnecessarily inaccurate because they don't rely on older but available U.S. data.
- The short sample period used in model estimation unnecessarily reduced the accuracy of cost model parameter estimates. The econometric estimate for the trend variable parameter was very sensitive to the sample period chosen and indicated that cost rose by 1.2% annually for reasons other than the values of the model's business condition variables.
- Transmission OM&A data for some U.S. utilities were non-comparable to Hydro One's due to their participation in ISOs or RTOs.
- U.S. input price indexes were used for Hydro One even though better Canadian indexes are available.

These and other concerns prompted us to undertake our own studies of Hydro One's transmission productivity and cost performance. The longer sample period that we used produces more accurate estimates of cost model parameters and long run transmission productivity trends. Our research is also based on better capital cost data and produces materially different and less favorable benchmarking results for Hydro One.

The Company's transmission cost performance has deteriorated markedly since 2008. Cost was found to be about 2.1% below the model's prediction on average from 2014-2016. The Company's forecasted/proposed total cost is 9.0% above our model's prediction on average during the 2020-2022 period.

Over the 2005-2016 historical sample period over which data are available for Hydro One transmission, we calculated the Company's transmission MFP to average a 1.17% annual decline while its OM&A productivity growth averaged 0.83% growth and its capital productivity averaged a 1.67% decline. The accuracy of our capital and multifactor productivity trend calculations is, like those of PSE, compromised by the unavailability of capital cost data for Hydro One before 2002. Over the two out years of the proposed IR plan, the Company's cost proposal/forecast is consistent with a 2.53% average annual MFP decline, 0.11% OM&A productivity growth, and a 2.94% annual capital productivity decline. Forecasted/proposed costs thus reflect capital and multifactor productivity growth that is well below longer-run U.S. norms.

Stretch Factor

We disagree with PSE's 0% stretch factor recommendation. One reason we disagree is that we do not get such favorable benchmarking results for Hydro One. Another is that we do not believe that the Company's base productivity trend proposal contains a large implicit stretch factor. We recommend a 0.30% stretch factor.

X Factor Recommendation

Our research supports a **-0.25%** base productivity trend drawn from our U.S. transmission MFP research for the full sample period with a **0.30%** stretch factor. The resultant X factor would be 0.05%.

Other Plan Design Issues

Hydro One's proposed IR plan is in many respects similar to that which the Board approved for Hydro One's distributor services in EB-2017-0049. We are nonetheless concerned about some features of Hydro One's proposal. The proposed ratemaking treatment of capital cost is our chief concern.

- Incentives to contain capex would be weakened by the proposed C factor, Capital In-Service Variance Account ("CISVA"), other capital cost variance accounts, and the Z factor provisions of the revenue cap index. The Company is perversely incented to spend excessive amounts on capital in order to trim OM&A expenses. The weak incentives to contain capex violate the spirit of the Board's Custom IR guidelines and are all the more worrisome given the capital-intensive nature of power transmission technology.
- Notwithstanding the CISVA, Hydro One is still incentivized to exaggerate its need for supplemental capital revenue. The regulatory cost for the OEB and stakeholders is

substantially raised and, ultimately, it is ratepayers who bear the burden of the capital cost increases.

- While customers must fully compensate Hydro One for expected capital revenue *shortfalls* when capex is high for reasons beyond its control, the Company need not return any *surplus* capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Over multiple plans, the revenue escalation between rate cases would not guarantee customers the full benefit of the industry's multifactor productivity trend, even when it is achievable.
- The kinds of capex accorded C-factor and variance account treatment are, for the most part, conventional transmission capex like that incurred by transmitters in studies used to calibrate base productivity trends. The Company can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.
- The RCI would effectively apply chiefly to the (modest) revenue for OM&A expenses and provide only a floor for revenue growth, even though it is not designed to play either of these roles.

We discuss several possible upgrades to the ratemaking treatment of capital cost in Section 6 of the report. Having considered the pros and cons of these options, we recommend an extra stretch factor term for setting the C-factor. The OEB first approved this kind of provision in its recent Hydro One Distribution decision.[9] The specific 0.42% supplemental stretch factor that we recommend would produce a markdown on eligible capex that is similar to that produced by the ACMs available to provincial power distributors in fourth-generation IRMs. The resultant C factor would average 3.50%.

We endorse the Company's proposal to be able to keep a small percentage of accumulated capex underspends because this provision strengthens capex containment incentives. We recommend that the Company's share of the value of underspends be 5%.

[9] EB-2017-0049. Decision and Order issued March 7, 2019.

2. Background

2.1 Hydro One's Previous Regulatory Systems

Hydro One's initial transmission revenue requirement was established in 1999 and updated to reflect a change in the Company's allowed rate of return on equity ("ROE") in 2000. After that, the Company's revenue requirement was unchanged until 2007. Hydro One subsequently filed rate cases in 2008, 2010, 2012, 2014, and 2016. Each rate case filing featured two forward test years. Concerns about capex underspending led to the adoption of an In-Service Capital Additions Variance Account which requires the Company to return the revenue impact of underspends to customers.

The OEB recently issued a decision that detailed an IRM for Hydro One SSM. This decision includes the following noteworthy provisions.

- An RCI allows revenue requirement escalation based on the formula Inflation less an X factor +/- Z factors. No scale escalator was approved for the RCI formula, and the Board commented that parties had presented insufficient evidence to justify the inclusion of such a term.
- Hydro One SSM's proposed inflation measure was accepted. The Board found that this measure was consistent with the inflation measures approved for Ontario power distributors in 4GIRM and Ontario Power Generation. Weights for the two inflation subindexes are 14% for labor and 86% for non-labor.
- The base productivity trend was set at zero, reflecting in part the OEB's prior decisions and their desire to keep base productivity trends non-negative. No party had supported a negative base productivity trend, even though both productivity studies presented in evidence reported negative MFP trends for U.S. transmitters. Transmission productivity results were very sensitive to the choice of sample periods, with PEG advocating for a longer sample period and PSE advocating for a shorter period. The Board found both the PSE and

PEG productivity studies "informative of the transmission sector, yet [found] both reports have inherent issues, dependent upon the sample periods selected."[10]

- The stretch factor was set at 0.3%. The Board chose this value in part because they believed that "a stretch factor of 0.3% provides incentives to find further efficiency improvement beyond those proposed by the acquisition."[11] The Board rejected Hydro One's proposed 0% stretch factor partly on the grounds that the benchmarking evidence presented in the proceeding pertained to Hydro One Transmission rather than to Hydro One SSM. Savings resulting from the integration of Hydro One SSM into Hydro One and the lengthy deferred rebasing period were not considered in the stretch factor selection. The Board also noted that PSE's "construction standards index" variable had not been fully vetted and questioned the relevance of this variable to Hydro One SSM.
- Hydro One SSM can request supplemental funding for capex through Incremental Capital Module filings.

The Board more recently approved the Company's request to escalate its revenue requirement by an RCI for a single year. The RCI had an I-X formula, where the I factor was set at 1.4% based on the record of Hydro One SSM and the X factor was set at 0%. The OEB explained its decision to not set a positive value for the X factor:

> The OEB normally applies a productivity factor and a stretch factor to incentive ratesetting indices to incent expected productivity improvements. The OEB is not imposing an explicit productivity factor for 2019 in this case given the short duration of the term. The OEB is specifically not making a finding on the appropriateness of a productivity factor or stretch factor of zero for the 2020 to 2022 period.[12]

2.2 Hydro One's Instant IR Proposal

Hydro One has in this proceeding filed a Custom IR application for its power transmission services. Under the proposal, a multiyear rate plan would set rates for the three-year 2020-2022 period. The revenue requirement for 2020 would be established by a conventional rebasing which uses a

[10] EB-2018-0218, p. 19.

[11] EB-2018-0218, p. 21.

[12] Ontario Energy Board (2019), Decision and Order EB-2018-0130 Hydro One Networks Application for 2019 Electricity Transmission Revenue Requirement, April 25, p. 7.

forward test year. Allowed revenue for 2021 and 2022 would then be set using an RCI with a formula that features an Inflation Factor ("I"), Productivity Factor ("X"), Custom Capital Factor ("C"), and Z factor.

$$growth\ RCI = I - X + C +/- Z.$$

The Company proposes an electricity transmission industry-specific inflation measure like that which the OEB adopted for Hydro One SSM. The growth rate of this measure would be a weighted average of the growth in two Statistics Canada inflation indexes: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the Average Weekly Earnings for Workers in Ontario ("$AWE^{Ontario}$"). The respective 86% and 14% weights on these two indexes would be based on the average shares of labor and other inputs in the total included transmission cost of the utilities in PSE's benchmarking sample. The inflation measure would be updated annually as calculated and issued by the OEB.

The proposed X factor would be fixed during the plan as the sum of a Custom Industry Total Factor Productivity ("TFP") (aka base productivity) trend and a Custom Productivity Stretch Factor. A 0% base productivity trend is proposed which is consistent with the OEB's 4th generation IRM decision.[13] The proposed 0.00% stretch factor is supported by PSE's total cost benchmarking report. PSE claims that a 0% X factor also includes a sizable *implicit* stretch factor since PSE found the transmission MFP trend of sampled electric utilities to be materiality negative in recent years.

The C Factor is the percentage change in the total revenue requirement which is needed to eliminate any positive difference between the growth in the Company's approved capital revenue requirement and the growth in its capital revenue that is otherwise produced by the RCI. The capital revenue requirement thus defined would include depreciation, return on rate base, and taxes. The Company's forecasted/proposed capital cost is supported by a Transmission System Plan.

Based on Hydro One's forecasted/proposed revenue requirement, proposed X factor, and forecasted annual inflation of 1.4% during the two indexing years, the Company estimates that the C-factor would average about 3.84% annually during the two indexing years of plan. RCI growth would

[13] OEB, EB-2010-0379, *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013 and as corrected on December 4, 2013.

average 5.24% annually. Thus, the C factor would accelerate allowed revenue growth substantially in 2021 and 2022.

Several of the Company's costs would be addressed by variance accounts. These would include the costs of pensions and other post-employment benefits, development of the Waasigan Transmission Line and East-West Tie line, and construction associated with the Supply to Essex County Transmission Reinforcement project. An asymmetrical CISVA would track the impact on the revenue requirement of 98% of any cumulative amount by which the value of in-service plant additions falls short of the OEB approved amount.

Hydro One could request Z factor treatment if a qualifying event occurred, based on the OEB's existing Z factor policy. A qualifying event would need to result in a change in the revenue requirement of $3 million or more.[14] Events that could trigger a Z factor claim include severe storms and investments that are government-mandated or outside of management's control for other reasons. Z-factor claims in Ontario may address OM&A and/or capital costs of qualifying events. While there is a materiality threshold, that threshold is not used as a dead zone, as is the case with the OEB's 4GIRM capital modules.

An asymmetrical earnings-sharing mechanism ("ESM") would share 50% of earnings which exceed the target rate of return on equity by more than 100 basis points. Earnings would be calculated in such a way that only those from OM&A would be addressed by this sharing mechanism. Hydro One has also proposed to apply the OEB's existing off-ramp policy. An off-ramp would be triggered if the actual achieved ROE on a regulated basis varied from the OEB-approved ROE by more than 300 basis points (i.e., ± 300 b.p.) in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This review would be prospective in nature and could result in modifications to the plan, the plan continuing without change, or the termination of the plan.

2.3 Custom IR Guidelines

The *Handbook for Utility Rate Applications* ("Rate Handbook") provides guidelines for energy utilities requesting Custom IR plans.[15] The OEB stated that

[14] Exhibit I, Tab 5, Schedule 7.

[15] OEB, *Handbook for Utility Rate Applications*, October 2016, pp. 18-19 and 24-28.

> The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).
>
> The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. **If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.
>
> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications**. **Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.**[16] [Emphasis added]

2.4 First Toronto Hydro Custom IR Proceeding

In its order approving Toronto Hydro's current (and expiring) Custom IR plan,[17] the OEB approved many of the basic features of subsequent Custom IR plans, including the adoption and calculation of the C factor, inclusion of an ESM, and the refund of capital underspends at the end of the plan term. The approved plan has a nearly 5-year term and escalates rates using the formula I – X + C, where I is the inflation factor, X is the sum of a 0% productivity trend and a 0.6% stretch factor, and C is a custom capital factor. A symmetrical ESM addresses non-capital related earnings variances outside of a 100-basis point dead band, while a variance account refunds all capex underspends to customers.

Despite approving much of Toronto Hydro's proposed Custom IR plan, the OEB expressed the following reservations about the quality of Toronto Hydro's filing.

> The OEB has determined that it cannot fully rely on Toronto Hydro's approach to establishing its spending proposals in determining if the outcome of that spending is desirable for ratepayers. It is not clear that Toronto Hydro's proposals are necessarily aligned with the interests of its customers, as they are largely supported by an asset condition analysis rather than the impact of the proposed work on the reliability of the system. The approach used by Toronto Hydro

[16] *Ibid*., pp. 25-26.

[17] EB-2014-0116

> does not give a clear indication of how the overall spending is related to customer experience such as reliability.
>
> The Application lacks evidence of corporate policy guiding Toronto Hydro staff to focus on impacts on customers when developing spending proposals. The focus overall is on the need for work based on asset condition assessment without a clear understanding of the results expected to be achieved through the work. Continuous improvement measurements are lacking
>
> …
>
> There does not appear to be any measurement of units of activity and their costs that would allow for year over year assessment of improvement in Toronto Hydro's proposed metrics. The OEB agrees with the parties which suggested that reporting measures such as specific performance improvements sought and achieved per asset class, tie-ins of capital program spending to the dollar value of OM&A savings achieved and how program spending specifically impacts the reliability and quality of service are desirable under the RRFE. However, as the RRFE is relatively new, the OEB does not expect all such measures to be implemented at once….
>
> In the absence of these parameters, Toronto Hydro's rates have been set based on the OEB's assessment of Toronto Hydro's historic expenditures, and the OEB's expectations with respect to improved productivity informed by the external benchmarking evidence of the expert witnesses for OEB staff and Toronto Hydro.[18]

The OEB cut Toronto Hydro's proposed capex budget by 10% annually for the Custom IR term, without specifying which proposed components were disallowed. Toronto Hydro was urged to find efficiencies during the term of the Custom IR plan. The OEB also expected Toronto Hydro to show improvements in reliability metrics due to increased capex and to provide evidence on the relationship between capital investments and reliability performance at its next rebasing.

The Toronto Hydro Custom IR decision also provided general commentary on what the Board expected Custom IR plans to entail:

> The Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. However, this is an example, not a condition precedent, and the OEB will not make a decision as to whether it is the best option for any particular distributor. **The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests**.[19] [Emphasis added]

[18] EB-2014-0116, OEB Decision and Order, Toronto Hydro-Electric System Limited, December 29, 2015, p. 6-7.

[19] *Ibid*., p. 4.

Presumably then, the OEB is open to further innovations in the design of Custom IRs intended to align customer and utility interests. The OEB further stated that:

> [a] Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.[20]

2.5 Hydro One Distribution's Recent IR Proceeding

Several aspects of the OEB's recent decision on Hydro One Distribution's Custom IR plan also suggest a wariness on the part of the Board with respect to multiyear capex forecasts and the related C factor. The Board disallowed $300 million (about 8.4%) of Hydro One Distribution's capex forecast.

In addition, the OEB ordered Hydro One Distribution to provide reports on various issues to show that the forecasts and expected efficiency gains it approved in this proceeding had been realized. For example, Hydro One Distribution was asked to report at the next rebasing on the actual performance of the capital program relative to the approved plan and improvements in performance in benchmarked areas (e.g., pole replacement) which resulted from discussing best practices with better performing peers. Hydro One Distribution was also ordered to report on the achievement of forecasted productivity savings.

The OEB also adopted an additional 0.15% stretch factor to apply solely to Hydro One Distribution's C-factor beyond the 0.45% stretch factor applied to the entire revenue requirement. This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."[21] The OEB was also influenced by Hydro One Distribution's prior capital overspending and comments by OEB Staff's expert witness that the C Factor led to perverse incentives for companies to spend excessive amounts on capital to contain OM&A expenses.

[20] *Ibid*., p. 5.

[21] *Ibid*., p. 32.

3. Critique of PSE's Research and Testimony

3.1 U.S. Power Transmission Productivity

PSE Study

PSE calculated the transmission productivity trends of Hydro One and 47 U.S. electric utilities over the twelve-year 2005-2016 period. A **-1.45**% average annual multifactor productivity growth trend was reported for the sampled transmitters over this period. Annual growth in OM&A productivity growth averaged -1.11% while capital productivity growth averaged -1.48%.

Growth in output was calculated using a multidimensional index with two scale variables: line length and ratcheted maximum peak demand.[22] The weights for these variables were obtained from an econometric model of total power transmission cost which PSE developed with data for 57 utilities for the 2004-2016 period. The weight for line length was 37% whereas the weight for peak demand was 63%.

Capital cost was measured using a variant of the geometric decay method in which capital gains were not considered.[23] The benchmark year in the capital cost computation was 2002 for Hydro One and 1989 for the sampled U.S. transmitters.

PEG Critique

Our examination of PSE's productivity research raised several concerns. To facilitate the Board's review of the numerous and often complicated issues that arise in productivity studies, we first highlight our chief concerns with PSE's methodology. There follows a brief discussion of some of our other concerns.

<u>Chief Concerns</u>

Sample Period A twelve-year sample period is fairly short for an X factor calibration study, and it is good practice to report results for a longer period when the practitioner favors a short period. Our

[22] The term ratcheted peak demand means that the value of the variable equals the highest monthly peak demand that has yet been attained during the sample period. This variable is a reasonable proxy for the expected maximum possible peak demand for grid services.

[23] Geometric decay and other monetary methods for calculating capital costs, prices, and quantities are discussed in Appendix Section A.2.

major concern with the 2005-2016 sample period, however, is that U.S. transmission productivity growth was strongly influenced during these years by special circumstances that included policy initiatives of the U.S. government. These initiatives included ROE premia for some kinds of transmission assets and FERC oversight over reliability standards that caused transmitters to incur Critical Infrastructure Protection ("CIP") costs. A related concern is that a large and growing number of the sampled transmitters operated under formula rate plans administered by the FERC during PSE's sample period. These plans feature comprehensive cost trackers that weakened transmitter cost containment incentives.

Transmission capex was also boosted during this period by the need to improve the functioning of bulk power markets and to access remote renewable resources whose development was encouraged by federal tax policy and state renewable portfolio standards. In addition to the fact that the slowdown in productivity growth due to CIP standards may be temporary, Hydro One may seek to Z factor any qualifying incremental CIP costs it incurs during the proposed plan term, or request incremental capital revenue by other means.

PSE makes no claim in its evidence that productivity results for its chosen sample period are particularly suitable for Hydro One during the term of the proposed plan. The reasons for negative MFP growth in the U.S. during its chosen sample period may be very different from the challenges that the Company faces. In response to OEB staff interrogatory 68 in the Hydro One SSM proceeding, PSE stated that it is uncertain about the drivers of negative productivity growth during this period, and that formula rate plans are widely used by U.S. transmitters and weaken their incentives.

The 2004 start date of PSE's sample period was ostensibly chosen due to the fact that this is the first year that data are available for a peak demand variable that PSE used in its econometric model and output index. PSE relied on the Monthly Transmission System Peak Load data reported on page 400 of the FERC Form 1. These data were first reported for 2004. We believe that it is reasonable to instead rely on the monthly peak load data, reported on page 401b of FERC Form 1, to construct the ratcheted peak demand variable. These alternative data are available for a longer sample period. Another concern we have about the data PSE used is that some companies misreported their peak load.[24]

Structural Change PSE's treatment of OM&A expenses does not handle structural change in the U.S. transmission industry well. As discussed further in Appendix C, many U.S. electric utilities joined independent system operators or regional transmission organizations in the last twenty years. These agencies performed some of the functions that the utilities had previously undertaken. Many utilities in the sample began purchasing a wide range of transmission services from these agencies, and this materially affected the reported costs of some companies.

Capital Cost Specification Our biggest concern about PSE's capital cost specification is that only capital cost data back to 1989 were employed for the sampled U.S. utilities even though the requisite data are available back to 1964 or earlier. Capital cost data for Hydro One are available only since 2002.[25] A failure to use older capital cost data can materially reduce the accuracy of capital cost and quantity estimates, as we discuss further in Appendix Section A.2.

3.2. Hydro One's Transmission Cost Performance

PSE Research

PSE also presented evidence on the transmission cost performance of Hydro One. It calculated the transmission MFP trend of Hydro One over the 2005-2016 period and the MFP trend that is implicit in the Company's forecasted/proposed costs from 2017 to 2022. Over the full historical sample period, the Company's -0.18% average annual multifactor productivity growth was considerably more positive than that which PSE reported for the full sample. OM&A productivity averaged 1.21% growth, while capital productivity averaged -0.45% annual growth. Over the 2021-2022 period during which the RCI would be operative under its proposed plan, the Company's forecasted/proposed costs would produce -1.70% annual MFP growth. OM&A productivity would average 0.11% annual growth while capital productivity would average -1.93% growth.

[24] For example, the Southern Company operating utilities reported the peak demand for the entire transmission system peak of these companies rather than at the individual operating company level. PSE has estimated the values for these companies.

[25]Hydro One apparently does not have plant value data that would permit an earlier benchmark year. We understand that this is due in part to historical circumstances beyond the Company's control.

PSE used its econometric transmission cost model to benchmark the total transmission cost of Hydro One, producing favorable results. The Company's cost was a substantial 21.8% below its econometric cost model's prediction on average over the three most recent years for which historical data were available (2014-2016). The Company's forecasted/proposed total cost is an even more favorable 27.1% below the model's predictions during the three years of the proposed plan.

PEG Critique

Our review of PSE's research on Hydro One's transmission services prompted several concerns. Here are the most important ones:

- The relatively short sample period of the econometric work unnecessarily reduces the precision of the econometric model parameter estimates.
- The particular sample period chosen is also likely to produce an inappropriately negative value for the trend variable parameter. The estimated value of this parameter is 0.012. This effectively permits benchmarked cost to grow by a substantial 1.2% annually for reasons other than changes in the values of the model's business condition variables.
- Parameter estimates are also degraded by the failure to use available older data in the U.S. capital cost calculations.
- Due to data limitations beyond the control of PSE, capital cost data are available for Hydro One only since 2002. This reduces the accuracy of total cost benchmarking and multifactor productivity results for the Company, especially in the early years of the sample period.
- We do not object in principle to the use of a weather-related construction standards index but note that it is an example of developing a variable to address a special cost disadvantage of the Company when special cost advantages could be ignored. Moreover, the accuracy of the calculation of the value for Hydro One is critically important, and we believe that PSE has misstated Hydro One's value. PSE conceded in its response to Staff IR 59 in the Hydro One SSM proceeding that

> Complete mapping of transmission lines in Canada and the United States is not publicly available. Therefore, for constructing this variable, PSE used the Hydro One Networks' retail service territory as a proxy for its transmission service territory.[26]

This assumption is problematic for Hydro One given that the Company claims a retail service territory that is the land area of Ontario that is unserved by other electric power distributors. This has the effect of including the northern reaches of Ontario, where Hydro One provides neither transmission nor distribution services.[27] These areas include much of the zones CSA Medium A and CSA Heavy located in Northern Ontario.

Review of the data for this variable is complicated by the limited transparency provided by PSE in the construction of this variable. For example, while PSE provided the values for each transmitter in its working papers, PSE did not provide the mapping data and underlying calculations to substantiate these values.

- The calculations do not use Ontario inflation indexes. Instead, PSE used U.S. inflation indexes adjusted for changes in the purchasing power parity ("PPP") between the U.S. and Canada. For example, the Handy Whitman Index of power transmission construction costs in the North Atlantic region of the United States was used to deflate the plant values of Hydro One. We believe that Canadian input price trend indexes such as the implicit capital stock deflator for the Canadian utility sector are more appropriate for Hydro One. PSE also used a U.S. employment cost index when the AWE of Ontario workers is readily available. The US gross domestic product price index was used as a proxy for trends in material and service ("M&S") prices when numerous macroeconomic Canadian price indexes are available.
- PSE forecasts that Hydro One's OM&A expenses will grow by forecasted OM&A price inflation. Since the Company's output growth is expected to be near zero, this implies 0% OM&A productivity growth. However, PSE calculated a 1.11% average annual decline in the OM&A productivity of sampled transmitters. This rosy scenario improves Hydro One's total cost

[26] EB-2019-0218, Exhibit I, Tab 1, Schedule 59, p. 4.

[27] This may somewhat offset the exclusion of areas in Ontario that are served by other power distributors in the CSA Heavy zone that borders much of the Great Lakes in southern Ontario.

performance score and reduces its potential stretch factor without involving any real commitment on the Company's part or benefits to customers.

Here are some less important but nonetheless notable concerns that we have with PSE's cost performance research for this proceeding.

- Only Toronto values were used to levelize the Company's construction cost index even though much of the transmission system is located far from Toronto.
- The levelization of the capital price is applied to the wrong year, as Mr. Fenrick conceded in the Hydro One technical conference.
- The 1.65 value for the declining balance parameter which PSE used to calculate the rate of decay for the capital quantity index formula was appropriate for transmission *equipment* but not for transmission *structures*.
- Only Handy Whitman indexes for *transmission* plant were used to calculate capital price and quantity trends even though a material portion of the assets in the calculations are *general* plant.

4. Alternative Empirical Research by PEG

4.1 Benefits of U.S. Data

Most power transmission in the United States is provided by investor-owned electric utilities ("IOUs").[28] These utilities usually also provide distribution services and some also provide generation services. The division between the transmission and distribution systems varies somewhat across the industry.

U.S. data have several advantages in transmission cost and productivity research.

- The federal government has gathered detailed, standardized data for decades on the operations of dozens of IOUs that provide transmission services. These services are broadly similar to those provided by Hydro One.
- IOU cost data are credibly itemized, permitting calculations of the cost of transmission services even for vertically integrated utilities.
- PEG has gathered data on the net value of plant in 1964 and the corresponding gross plant additions since that year. Custom indexes are available on trends in the costs of transmission and general plant construction. These advantages make U.S. data the best in the world for accurate calculation of the consistent capital cost, price, and quantity indexes that are needed to appraise the capital cost and total cost performances of power transmitters.

In contrast, data on the transmission operations of utilities in the various provinces of Canada are not standardized. Consistent data on transmission capital costs are available for numerous years in only a few provinces, and even in these provinces are generally not available before 2000. PSE invited nine Canadian transmission utilities to participate in its study for Hydro One but none complied.

4.2 Data Sources

The source of data on the transmission cost, transmission system scale, and peak demand of U.S. electric utilities which we used in our empirical research was FERC Form 1. Data reported on Form

[28] Some federal and municipal utilities and rural electric cooperatives also provide power transmission services.

1 must conform to the FERC's Uniform System of Accounts. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[29] More recently, these data have been available electronically in raw form from the FERC, and in more processed forms from commercial vendors such as SNL Financial.[30]

Data on U.S. salary and wage prices were obtained from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The gross domestic product price index ("GDPPI") that we used to deflate M&S expenses of U.S. transmitters was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on the *levels* of heavy construction costs in various U.S. and Ontario locations were obtained from RSMeans. Data on U.S. electric utility construction cost *trends* were drawn from the *Handy Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates. Some of the business condition variables we used in our econometric cost model were obtained from PSE working papers.

4.3 Sample

Data for Hydro One and 43 U.S. transmitters were used in our productivity research. Data for Hydro One and 52 U.S. transmitters were used in our econometric research.[31] A larger sample is possible for the econometric work because a balanced panel (i.e., one with the same number of observations for each company) is not required. Table 1 provides a list of the sampled utilities.

The sample period for our econometric cost research was 1995-2016. The full sample period for our productivity research was 1996-2016. The additional years of data increase the precision of the econometric parameter estimates and produce results that are less sensitive to the unusual operating environment that transmitters in the States encountered after 2005.

[29] This publication series had several titles over the years. The most recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.

[30] PSE evidently used SNL Financial data in its research.

[31] PEG excluded several companies from the sample that PSE used due to data problems. Reasons for these exclusions are provided in Appendix B.4.

Table 1

Sample of Utilities Used in PEG's Alternative Cost Research

Alabama Power	Kansas Gas & Electric
ALLETE (Minnesota Power)	Kentucky Utilities
Arizona Public Service	Louisville Gas & Electric
*Atlantic City Electric	Mississippi Power
Avista	Monongahela Power
*Baltimore Gas & Electric	New York State Electric & Gas
Central Hudson Gas & Electric	*Niagara Mohawk Power
*Central Maine Power	Northern States Power - Minnesota
Cleco Power	Oklahoma Gas & Electric
Commonwealth Edison	*Orange & Rockland Utilities
Connecticut Light & Power	Pacificorp
Consolidated Edison of New York	PECO Energy
*Delmarva Power & Light	Potomac Electric Power
Duke Energy Carolinas	Public Service Company of Colorado
*Duke Energy Florida	*Public Service Electric & Gas
Duke Energy Indiana	Rochester Gas & Electric
Duke Energy Ohio	San Diego Gas & Electric
Duke Energy Progress	South Carolina Electric & Gas
Duquesne Light	Southern California Edison
El Paso Electric	Southern Indiana Gas & Electric
Empire District Electric	Southwestern Public Service
Florida Power & Light	Tampa Electric Company
Gulf Power	Tucson Electric Power
Hydro One Transmission	Union Electric
Idaho Power	West Penn Power
Indianapolis Power & Light	
*Jersey Central Power & Light	
Kansas City Power & Light	

*This company is in the econometric sample but not the TFP Sample.

4.4 Variables Used in the Research

Costs

The main task of a power transmitter is the long distance transmission of power. This is done at high voltage to reduce line losses. Transmitters typically own and operate substations that reduce the voltage of the power they carry before it is delivered to distribution systems. Many transmitters also own substations that increase the voltage of power received from generators. The principal assets used in transmission are high-voltage power lines, the towers and underground facilities that carry them, and substations. Other notable transmission assets include circuit breakers and land.

The cost of power transmission considered in our study was the sum of applicable capital costs and OM&A expenses. The capital costs we included were those for transmission plant and a sensible share of the cost of general plant. We employed a monetary approach to capital cost, price, and quantity measurement which featured a geometric decay specification. Capital cost was the sum of depreciation expenses and a return on net plant value.[32]

The OM&A expenses we used in the study included most of those reported for power transmission, along with a sensible share of many reported administrative and general expenses. We excluded some categories of transmission OM&A expenses out of concern that those of many sample utilities have been affected by independent system operators and regional transmission organizations as to compromise their comparability and exogenous character. The categories excluded on this basis are: transmission by others (account 565), load dispatching (accounts 561-561.8), maintenance of miscellaneous regional transmission plant (569.4) and miscellaneous transmission expenses (566).

Pension and other benefit expenses were also excluded from this study. One reason is that these expenses are sensitive to volatile external business conditions such as stock prices. In Canada, an additional problem with including pension and benefit expenses is the lack of federal labor price indexes that encompass them along with salaries and wages. The health insurance obligations of U.S. and Canadian utilities can differ considerably. Hydro One proposes to Y factor pensions and other post-employment benefits. Pension and benefit expenses are often excluded from statistical cost performance studies. We also excluded from this study all reported taxes and the OM&A expenses incurred by the utilities for power generation, procurement, regional market activities, distribution, customer accounts, customer service and information, sales, franchise fees, and gas services.

[32] General issues in the measurement of capital cost are discussed in Appendix section A.2. Details of our capital cost calculations are provided in Appendix section B.1.

Input Prices

OM&A

Summary OM&A input price indexes were used in our research which featured subindexes for labor and materials and services.[33] We used PSE's Ontario and U.S. price levels for salaries and wages. Values of each U.S. company's labor price index for other years were calculated by adjusting these levels for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. For Hydro One, we escalated the salary and wage price level using the $AWE^{Ontario}$ industry time series reported by Statistics Canada.

For M&S price inflation in the United States we used the U.S. GDPPI. This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include business equipment and exports as well as consumer products. For the M&S price inflation of Hydro One we used Statistics Canada's $GDPIPIFDD^{Canada}$.

In our econometric work the summary OM&A input price indexes used fixed 38% labor/62% M&S weights that were calculated by PSE using data from its benchmarking sample. For our U.S. productivity research, we instead used company-specific, time-varying cost share weights that we calculated from FERC Form 1 OM&A expense data.

Capital

Asset price indexes and rates of return on capital are required in the capital cost research. For the U.S. utilities we calculated 50/50 averages of rates of return for debt and equity.[34] For debt we used the embedded average interest rate on long-term debt of a large group of electric utilities as calculated from FERC Form 1 data. For equity we used the average allowed ROE approved in electric utility rate cases as reported by the Edison Electric Institute.[35] For Hydro One Networks, we employed the weighted average cost of capital that PSE used in its study.

[33] The formulas for our input price indexes are discussed further in Appendix B.1.

[34] This calculation was made solely for the purpose of measuring productivity *trends* and benchmarking cost performance and does not prescribe appropriate rate of return *levels* for utilities.

[35] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

As transmission asset price trend indexes for U.S. utilities we used the regional Handy Whitman Indexes of Public Utility Construction Costs for Total Transmission Plant. As general plant asset price indexes we used the Handy Whitman Indexes of Public Utility Construction Costs for reinforced concrete building construction. As an asset price trend index for Hydro One we used Statistics Canada's implicit capital stock deflator for the utility sector of Canada. Statistics Canada includes in the utility sector power generation and transmission, gas distribution, and water and sewer utilities as well as power distribution.

Multifactor

The summary multifactor input price indexes that we used in the econometric research were constructed for each transmitter by combining the capital and summary OM&A price indexes using company-specific, time-varying cost share weights.

U.S./Canada Price Patch

Since U.S. and Canadian cost data were used in the study, it was necessary to make some adjustments for differences in currencies in the two countries. M&S prices were patched using US/Canadian purchasing power parities computed by the Organization for Economic Cooperation and Development ("OECD"). Construction and labor price indexes did not require a special patch.

Output Variables

Two output (aka scale) variables were used in our econometric cost model: length of transmission line and ratcheted maximum peak demand. The line length data were drawn from Transmission Line Statistics on page 422 of FERC Form 1. To construct the ratcheted peak demand variable we used the monthly peak load data found on page 401b of the FERC Form 1 rather than the peak transmission demand data on which PSE relied.[36] Our econometric research revealed that a ratcheted peak demand variable constructed using these data had better explanatory power than the variable used by PSE.

[36] An idiosyncrasy of these alternative demand data is that they do not include non-requirements sales for resale. The requirement sales for resale that are included are contractually firm enough that the party receiving the power is able to count on it for system capacity resource planning. Non-requirements sales for resale do not meet this standard and include economy energy. The load associated with non-requirements sales for resale can be shed in times of capacity constraints.

We followed PSE's practice of according the two scale variables in our model a translog treatment by adding quadratic and interaction (aka "second-order") terms for these variables to the econometric cost model. No second-order terms were included in this model for the other variables in the model. Functional form issues are discussed further in Appendix Section B.2.

Other Business Condition Variables

Five other business condition variables were included in our econometric cost model. Three of these variables address characteristics of the transmission system. These are substation capacity per substation, the average voltage of transmission lines, and the share of assets overhead.[37] We expect the parameters of the first two to have positive signs, while the parameter for the last variable should have a negative sign. The model also includes the construction standards index for transmission tower construction which PSE developed and the share of transmission plant in the utility's non-general gross plant value. The latter variable should indicate the extent to which the utility was unable to realize economies of scope from the joint provision of transmission and distribution (and in some cases generation) services. We expect both of these variables to have positive parameter estimates.

Our model also contains a trend variable. This permits predicted cost to shift over time for reasons other than changes in the specified business conditions. Trend variables thereby capture the net effect on cost of diverse conditions, such as technical change, which are otherwise excluded from the model. Parameters for such variables often have a negative sign in econometric research on utility cost. However, the expected value of the trend variable parameter in a cost model is *a priori* indeterminate.

4.5 Econometric Results

We used the assembled data to develop an econometric model of the total cost of power transmission. The dependent variable in this research was *real* total cost: the ratio of total cost to the multifactor input price index. This specification enforces a key result of cost theory.[38]

[37] The extent of transmission plant overheading was measured as the share of overhead plant in the gross value of transmission conductor, device, and structure (pole, tower, and conduit) plant. System overheading typically involves lower capital costs. Since transmission is a capital-intensive business, high overheading should lower total cost.

[38] Theory predicts that 1% growth in a multifactor input price index should produce 1% growth in cost.

Results of our econometric work are reported in Table 2. This table includes parameter estimates and their associated asymptotic t-statistics and p-values. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development.

Examining the results in the table, it can be seen that the parameters of the business condition variables have sensible signs and parameter values.[39] Our research indicates that transmission costs tended to be higher to the extent that sampled utilities had:

- higher ratcheted maximum peak demand
- longer and higher voltage transmission lines
- more substation capacity per substation
- more transmission facilities underground
- transmission plant that constituted a larger share of total non-general plant
- higher construction standards.

The parameter estimates for the scale variables suggest that ratcheted peak demand had an estimated long-run cost elasticity of 0.571% whereas the estimated cost elasticity of transmission line length was 0.492%. The parameter estimate for the trend variable suggests that transmission cost tended to *fall* over the full sample period by about 0.6% annually for reasons that aren't explained by the business condition variables in the model. The adjusted R-squared for the model is 0.948.

4.6 Productivity Research

Methodology

We calculated indexes of the OM&A, capital, and multifactor transmission productivity of Hydro One and each U.S. utility in our sample. The annual productivity growth rate of each transmitter was calculated as the difference between the growth of its output and input quantity indexes. Cost-

[39] This remark pertains to the "first" order terms in the model, and not to the parameters of the second-order (quadratic and interaction) terms.

Table 2
PEG's Alternative Econometric Model of Transmission Total Cost

VARIABLE KEY

YL =	Kilometers of transmission line
D =	Ratched maximum peak demand
MVA =	Substation capacity per substation
VOLT =	Average voltage of transmission line
CS =	Construction standards index
PCTPOH=	Percent of transmission plant that is overhead
PCTPTX =	Percent of transmission plant in total plant
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.492	26.154	0.000
YL * YL	0.402	14.499	0.000
YL * D	-0.207	-8.447	0.000
D	0.571	30.634	0.000
D * D	0.243	7.307	0.000
MVA	0.044	2.350	0.019
VOLT	0.063	2.076	0.038
CS	0.238	5.239	0.000
PCTPOH	-0.395	-8.340	0.000
PCTPTX	0.140	10.538	0.000
Trend	-0.006	-7.270	0.000
Constant	12.173	695.103	0.000

Adjusted R^2	0.948
Sample Period	1995-2016
Number of Observations	1,127

weighted averages of these growth rates were then calculated. Cost weighting makes particular sense when calibrating the X factor of a large utility like Hydro One.

The growth rates of our output indexes were weighted averages of the growth in line kilometers and ratcheted maximum peak demand. The estimated cost elasticities for these two variables from our econometric research were used to establish weights. The weights were about 54% for ratcheted maximum peak demand and 46% for line length.

In calculating input quantity indexes for the U.S. utilities we broke down their applicable cost into those for transmission capital, general capital, labor, and M&S inputs. Each of these input groups had its own quantity subindex. The trend in each company's multifactor input quantity index was a weighted average of the trends in the four subindexes. The weights on these indexes were company-specific and time-varying. We also calculated summary OM&A and capital quantity indexes. The calculation of the input quantity trend for Hydro One instead used a single, consolidated capital quantity index for transmission and general plant.

Industry Trends

Table 3 reports results of our productivity calculations for the full sample. We found that the growth in the transmission MFP of sampled U.S. utilities averaged **-1.47**% over PSE's chosen 2005-2016 sample period but a more positive **-0.25**% over our full 1996-2016 sample period, during which the effects of formula rates and other recent changes in the U.S. transmission business were less pronounced. OM&A productivity growth averaged -1.64% over PSE's sample period but -0.69% over our full period. Capital productivity growth averaged -1.45% over PSE's sample period but -0.19% over our full period.

Our estimates of transmission output do not reflect any possible improvements in U.S. transmission reliability or bulk power market performance. Reliability is treated as an output variable in transmission productivity research commissioned by the Australian Energy Regulator. PSE acknowledged in response to OEB staff interrogatory #63 that reliability can be an output in a productivity study. [40]

[40] EB-2018-0218, Exhibit I/Tab 1/Schedule 63. The OEB adopted the evidentiary record from EB-2018-0218 into the current proceeding, by way of its letters of June 28 and July 4, 2019.

Table 3

U.S. Transmission Productivity Results Using PEG's Methods: Cost-Weighted Averages

(Growth Rates)[1]

		Input Quantity Index					Productivity				
		OM&A	Capital			Multifactor	OM&A	Capital			Multifactor
Year	Output Quantity Index		Transmission	General	Capital Summary			Transmission	General	Capital Summary	
1996	1.13%	-0.27%	-0.43%	0.60%	-0.39%	-0.30%	1.39%	1.56%	0.53%	1.52%	1.43%
1997	0.81%	0.63%	-0.51%	-4.34%	-0.58%	-0.71%	0.18%	1.32%	5.15%	1.39%	1.53%
1998	1.39%	0.72%	-1.21%	2.68%	-1.12%	-0.72%	0.67%	2.61%	-1.29%	2.51%	2.11%
1999	1.33%	-5.87%	-1.23%	-2.59%	-1.28%	-1.48%	7.20%	2.56%	3.92%	2.61%	2.81%
2000	0.58%	6.36%	-0.68%	7.64%	-0.50%	0.10%	-5.78%	1.26%	-7.06%	1.08%	0.48%
2001	1.63%	0.39%	-0.27%	14.22%	0.02%	0.04%	1.25%	1.90%	-12.59%	1.61%	1.60%
2002	0.54%	-4.40%	-0.06%	-6.67%	-0.09%	-0.60%	4.93%	0.60%	7.20%	0.63%	1.14%
2003	1.50%	3.46%	-0.36%	1.32%	-0.31%	0.04%	-1.96%	1.86%	0.18%	1.82%	1.46%
2004	0.45%	3.15%	0.18%	1.93%	0.19%	0.65%	-2.70%	0.27%	-1.49%	0.25%	-0.20%
2005	2.34%	6.81%	0.41%	2.35%	0.43%	1.20%	-4.47%	1.93%	-0.01%	1.91%	1.14%
2006	1.63%	1.74%	0.46%	-2.27%	0.43%	0.69%	-0.11%	1.17%	3.91%	1.21%	0.94%
2007	1.02%	5.27%	1.16%	-2.43%	1.07%	1.59%	-4.25%	-0.14%	3.45%	-0.05%	-0.57%
2008	0.45%	3.73%	1.15%	3.15%	1.18%	1.36%	-3.28%	-0.70%	-2.69%	-0.73%	-0.91%
2009	-0.20%	3.18%	2.27%	1.08%	2.24%	2.45%	-3.38%	-2.47%	-1.28%	-2.44%	-2.64%
2010	0.64%	5.83%	1.69%	-0.73%	1.60%	2.31%	-5.19%	-1.06%	1.36%	-0.96%	-1.67%
2011	0.33%	-0.07%	2.31%	0.92%	2.24%	1.86%	0.41%	-1.98%	-0.58%	-1.90%	-1.52%
2012	0.60%	0.30%	1.68%	5.11%	1.68%	1.26%	0.29%	-1.09%	-4.52%	-1.08%	-0.66%
2013	0.25%	2.59%	4.02%	7.73%	4.03%	3.86%	-2.34%	-3.77%	-7.48%	-3.78%	-3.61%
2014	0.79%	-2.39%	3.75%	-0.37%	3.69%	3.10%	3.18%	-2.96%	1.17%	-2.90%	-2.30%
2015	0.62%	-2.80%	4.01%	2.49%	4.01%	3.08%	3.42%	-3.39%	-1.87%	-3.39%	-2.46%
2016	-0.14%	3.88%	3.17%	7.04%	3.21%	3.28%	-4.02%	-3.31%	-7.18%	-3.35%	-3.42%
Average Annual Growth Rates											
1996-2016	**0.84%**	**1.54%**	**1.02%**	**1.85%**	**1.03%**	**1.10%**	**-0.69%**	**-0.18%**	**-1.01%**	**-0.19%**	**-0.25%**
2005-2016	**0.70%**	**2.34%**	**2.17%**	**2.01%**	**2.15%**	**2.17%**	**-1.64%**	**-1.48%**	**-1.31%**	**-1.45%**	**-1.47%**

[1]All growth rates are calculated logarithmically.

Hydro One Networks' Trends

Table 4 reports results of our transmission productivity calculations for Hydro One. Over the full 2005-2016 sample period for which Hydro One's historical data are available, the Company's annual multifactor productivity growth averaged -1.17% while its OM&A productivity growth averaged 0.83% and its capital productivity growth averaged -1.67%. The accuracy of the capital and multifactor productivity results for Hydro One is reduced by the unavailability of older capital cost data.

Over the two out years of the proposed plan (2021-2022), the Company's forecasted/proposed costs are consistent with -2.53% average multifactor productivity growth, 0.11% OM&A productivity growth, and -2.94% capital productivity growth. The Company's forecasted/proposed costs thus reflect

Table 4

Hydro One's Transmission Productivity Growth

(Growth Rates)[1]

Year	Output Quantity Index	Input Quantities OM&A	Input Quantities Capital	Input Quantities Multifactor	Productivity OM&A	Productivity Capital	Productivity Multifactor
2005	1.43%	-9.42%	0.32%	-1.80%	10.85%	1.11%	3.23%
2006	1.88%	10.14%	-0.22%	2.06%	-8.26%	2.10%	-0.18%
2007	0.00%	10.51%	1.46%	3.62%	-10.51%	-1.46%	-3.62%
2008	0.08%	-15.01%	0.32%	-3.24%	15.09%	-0.24%	3.32%
2009	-0.01%	11.84%	2.49%	4.56%	-11.85%	-2.50%	-4.57%
2010	0.04%	-1.38%	3.87%	2.69%	1.42%	-3.83%	-2.65%
2011	0.04%	-4.07%	3.01%	1.48%	4.11%	-2.97%	-1.44%
2012	0.44%	0.19%	5.68%	4.54%	0.24%	-5.24%	-4.10%
2013	0.03%	2.30%	1.52%	1.68%	-2.27%	-1.50%	-1.65%
2014	-0.05%	-11.22%	2.77%	0.09%	11.17%	-2.82%	-0.14%
2015	0.15%	9.92%	0.71%	2.43%	-9.78%	-0.57%	-2.28%
2016	0.00%	-9.69%	2.14%	-0.03%	9.69%	-2.14%	0.03%
2017	-0.58%	-5.26%	1.77%	0.57%	4.68%	-2.35%	-1.15%
2018	0.61%	-1.97%	3.25%	2.40%	2.58%	-2.64%	-1.78%
2019	0.00%	-16.81%	1.78%	-0.99%	16.82%	-1.77%	1.00%
2020	0.00%	4.06%	2.03%	2.31%	-4.06%	-2.03%	-2.31%
2021	0.01%	-0.10%	3.13%	2.69%	0.10%	-3.12%	-2.68%
2022	0.01%	-0.10%	2.77%	2.38%	0.11%	-2.76%	-2.37%
Average Annual Growth Rates							
2005-2016	**0.34%**	**-0.49%**	**2.01%**	**1.51%**	**0.83%**	**-1.67%**	**-1.17%**
2012-2016	**0.11%**	**-1.70%**	**2.57%**	**1.74%**	**1.81%**	**-2.45%**	**-1.63%**
2021-2022	**0.01%**	**-0.10%**	**2.95%**	**2.53%**	**0.11%**	**-2.94%**	**-2.53%**

[1]All growth rates are calculated logarithmically.

OM&A productivity growth that is well above industry norms but capital productivity growth that is well below industry norms.

4.7 Cost Benchmarking Results

We used our econometric transmission cost model to benchmark the total transmission cost of Hydro One. In this exercise we used PSE's forecasts for growth in input prices. Due to unavailability of older capital cost data, results will tend to be more accurate in the later years.

Results of our benchmarking work are presented in Table 5. It can be seen that the Company's transmission cost performance began a steady decline after 2008. Its cost was about 2.1% below the model's prediction on average from 2014 to 2016, the three most recent historical years for which data for all required variables were available. The Company's forecasted/proposed total costs are about 9.0% above the model's prediction on average during the three years of its proposed IR plan (2020-2022).

Table 5

Transmission Total Cost Performance of Hydro One Using PEG's Econometric Model

[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark Score
2004	-20.5%
2005	-23.3%
2006	-22.5%
2007	-19.5%
2008	-21.4%
2009	-18.0%
2010	-15.7%
2011	-12.9%
2012	-10.4%
2013	-4.8%
2014	-4.9%
2015	-0.4%
2016	-0.9%
2017	1.5%
2018	2.5%
2019	3.5%
2020	6.2%
2021	8.7%
2022	12.0%
Average 2004-2016	**-13.5%**
Average 2014-2016	**-2.1%**
Average 2020-2022	**9.0%**

1 Formula for benchmark comparisons is $\ln(Cost^{HON}/Cost^{Bench})$.

5. X Factor Recommendations

5.1 Base Productivity Trend

We believe that the **-0.25**% trend in the MFP of the U.S. power transmission industry which we calculated for our full 1996-2016 sample period is a reasonable base productivity trend for Hydro One.

5.2 Stretch Factor

We disagree with PSE's 0.0% stretch factor recommendation, which is based on the contentions that an explicit stretch factor is not warranted given Hydro One's superior cost performance and that there is a large implicit stretch factor in the 0.0% base productivity trend. Here are the considerations we feel are pertinent for choosing a stretch factor.

- The Company's cost performance does not score as well in our study as in PSE's study. We found that the Company's forecasted/proposed total cost during the three years of the proposed plan would be 9.0% above our model's prediction on average. In 4GIRM this kind of cost benchmarking score is commensurate with a 0.3% stretch factor.
- Stretch factors should also reflect the difference between the incentive power of the proposed plan and the incentive power of the regulatory systems of companies in the productivity studies used to calibrate the stretch factor. The incentive power of the proposed plan is not strong due to the comparatively short three-year term, the ESM, and the capital cost trackers. On the other hand, the incentive power of U.S. transmission regulation was significantly weakened by the FERC's use of ROE premia and formula rate plans, particularly during PSE's shorter and more recent sample period.
- The MFP growth trend of the transmission industry is considerably more rapid (though still negative) using our alternative sample period and methods. PSE has not made a persuasive case as to why the unusually negative MFP growth of U.S. transmitters in recent years is applicable to Hydro One despite large differences in operating conditions.
- The RCI formula does not include a scale escalator to help fund output growth. On the other hand, the plan includes variance accounts for costs of major line extensions, and supplemental revenue for growth-related capex may also be obtained via the C factor.

Growth in the Company's output has been slow in recent years and this is expected to continue.

- Stretch factors linked to cost performance have the additional benefit of serving as efficiency carryover mechanisms that reward utilities for long-term cost savings and penalize them for their absence.

Balancing these considerations, we believe that a 0.30% stretch factor is reasonable for Hydro One.

5.3 X Factor

A -0.25% base productivity trend and a 0.30% stretch factor would produce a 0.05% X factor. This is the X factor that we recommend.

6. Other Plan Design Issues

The other provisions of Hydro One's proposed transmission Custom IR are in some respects uncontroversial. We have noted that the plan is similar to Custom IRs that the Board has approved for other utilities. We are nonetheless concerned about some features of Hydro One's proposal.

The proposed ratemaking treatment of capital is our chief concern. The C factor would ensure that the Company would recover almost all of its projected/proposed capital cost if it incurred this cost. Almost all of any cumulative capex underspend would be returned to the ratepayer. Several additional variance accounts and the Z factor would also address capex. Hence, capital revenue would chiefly be established on a cost of service basis.

Despite the proposed clawback of capex underspends, Hydro One would still have some incentive to exaggerate its capex needs, since exaggerations strengthen the case for a C Factor and reduce the pressure on the Company to contain capex. Exaggeration of capex needs may reduce the credibility of Hydro One's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under several generations of IR plans with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted. Hydro One would also be incentivized to "bunch" its deferrable capex in ways that increase supplemental revenue. If, for example, the Company could somehow manage to time its capex so that the $I - X$ escalation was compensatory, it would obtain no supplemental revenue.

The clawback of almost all capex underspends and the variance account and Z factor treatments of some kinds of capex would greatly weaken the Company's incentive to contain capex. Incentives to contain capex and OM&A costs would be imbalanced, creating a perverse incentive to incur excessive capex in order to reduce OM&A costs. The Company actually stated in its application that it needs to keep 2% of capex underspends

> to ensure alignment between the behaviours that are incented by the account and the outcomes that rate payers value. … Absent the 2% dead band, Hydro One is incented to fully spend 100% of its planned capital amounts and focus on identifying any additional productivity initiatives on OM&A programs where part of the savings can be kept by the utility.[41]

[41] Exhibit A, Tab 4, Schedule 1, p. 11.

The weak incentives to contain capex are inconsistent with the Board's Custom IR guidelines which, as we noted in Section 2.3, proscribe a multiyear cost of service approach, require "explicit financial incentives for continuous improvements and cost control targets," and beyond the stretch factors used in 4GIRM. This reality is all the more sobering when it is remembered that power transmission is an unusually capital-intensive business.

Another problem with the proposal is that while customers must fully compensate Hydro One for expected capital revenue *shortfalls* when capex is high for reasons beyond its control, the Company need not return any *surplus* capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Slow capital cost growth may very well occur in the future for reasons other than good cost management. For example, depreciation of recent and prospective surge capex will tend to slow future capital cost growth and accelerate productivity growth. Over multiple plans, the revenue escalation between rate cases would not guarantee customers the full benefit of the industry's multifactor productivity trend, even when it is achievable.

A related problem is that most of the capex addressed by the C factors, capital variance accounts, and Z factors would be similar in kind to that incurred by transmitters sampled in past and future productivity studies that are used to calibrate Hydro One's X factors.[42] The Company can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, Hydro One's weak incentive to contain capex, and the Company's incentive to exaggerate capex requirements and bunch capex, stakeholders and the Board must be especially vigilant about the Company's capex proposal.[43] This raises regulatory cost. The need for the OEB to sign off on multiyear total capex proposals greatly complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews transmission business plans - a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB staff and stakeholders will inevitably struggle to effectively challenge the Company's capex proposal. In essence, the OEB's Custom IR rules

[42] Hydro One would not, however, be compensated during the plan for capex overruns.

[43] Proposed programs that raise capex and reduce OM&A expenses merit especially close examination.

have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements, without necessarily making the same investment that British (and Australian) regulators have made in the capability for appraising and ruling on multiyear capex proposals.[44]

Another concern is that the substantial compensation for capex funding shortfalls which has been permitted by the OEB under Custom IR may be more remunerative than that available under the ACMs and ICMs featured in 4GIRM. These modules feature materiality thresholds that include a markdown on capex eligible for supplemental revenue. If the markdowns under Custom IR and 4GIRM are imbalanced, utilities may choose Custom IR, with its weaker performance incentives and higher regulatory cost, even though compensatory operation under 4GIRM is feasible.

In pondering this quandary, the following remarks of the OEB in its decision approving Toronto Hydro's expiring Custom IR plan resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[45]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient utilities.

The Alberta Utilities Commission ("AUC") faced a similar challenge following an unhappy experience with capital cost trackers in their first-generation IR plans for provincial gas and electric power distributors. A number of possible reforms to the ratemaking treatment of capital were discussed in the AUC's generic proceeding on second-generation plans. The AUC eventually chose a means for providing supplemental capital revenue which was much less dependent on distributor capex forecasts. Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

[44] Consider, for example, that Ofgem's own view of a power transmitter's required cost growth is assigned a 75% weight in contested IR proceedings. This view is supported by independent engineering and benchmarking.

[45] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

A "K-bar" value was established for each distributor for the first year of the plan based on the extent to its recent *historical* capex levels, adjusted for growth in inflation, X, and billing determinant growth, were not funded by base rates. K-bar values in subsequent years have been escalated by the growth in rate or revenue cap index. Capital cost trackers may be requested to provide supplemental funding for eligible capex of a type that is required by a third party and extraordinary and not previously included in the distributor's rate base.[46]

Informed by our research and testimony for a party to that Alberta proceeding, and by our familiarity with Custom IR, we believe that the following alternatives to Hydro One's proposed ratemaking treatment of capital merit consideration.

- An obvious candidate for a different approach is that chosen by the OEB in their recent decision on IR for Hydro One's distributor services.[47] A supplemental stretch factor would apply to the calculation of the C factor.
- Eligibility of capex for supplemental C factor revenue could be scaled back by other means. For example, capex in the last year of the plan term could be declared ineligible for supplemental revenue because this involves only one year of underfunding.
- The X factor could be raised, mechanistically in the Company's future IRMs, to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. This would be tantamount to having the Company borrow revenue escalation privileges from future plans. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Hydro One's capex containment incentives.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans. Once again, knowledge that there is a price to be paid in the long run for

[46] In the first generation of PBR plans in Alberta, capital cost trackers were the sole means by which a distributor could obtain supplemental funding for eligible capex.

[47] OEB, *Decision and Order*, EB-2017-0049, March 7, 2019.

asking for extra revenue now would strengthen Hydro One's capex containment incentives. The IR plans for the Fortis companies in British Columbia track the cost of *all* older capital.

- The proposed capex budget could be reduced by a material amount, as in the OEB's decisions in the last Toronto Hydro proceeding and the Hydro One distribution IR proceeding.

After considering the pros and cons of these options, we recommend that the OEB add a supplemental stretch factor to Hydro One's C factor calculation and calibrate this factor so that it produces a markdown on plant additions that is similar to that which would be produced by an ACM. We calculate that the analogous stretch factor would average about 0.42%. Details of our calculations can be found in Appendix Section B.4.

Several arguments can be advanced for making the supplemental capital cost stretch factor even higher.

- The Board rationalized the 10% markdown factor for ACMs and ICMs chiefly on the grounds that it may reduce regulatory cost. We have ventured a much wider range of arguments in favor of a markdown.
- As further discussed in Appendix B.4, the 10% markdown factor actually marks down otherwise-eligible capex by considerably less than 10%.

Hydro One should, in our view, be permitted to keep a share of the value of any capex underspends. This would strengthen the Company's incentive to contain capex (but also its incentive to exaggerate its capex needs). We believe that the Company should be permitted to keep 5% of the value of capex underspends.

Appendix A: Index Research for X Factor Calibration

In this section of the report we discuss pertinent principles and methods for the design of revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing research in revenue cap index design and other important methodological issues.

A.1 Principles and Methods for Revenue Cap Index Design

Basic Indexing Concepts

Input Price and Quantity Indexes

The growth rate of a company's cost can be shown to be the sum of the growth in a cost-weighted input price index ("*Input Prices*") and input quantity index ("*Inputs*").

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Inputs}. \qquad [A1]$$

These indexes summarize growth in the prices and quantities of the various inputs that a company uses. Capital, labor, and miscellaneous materials and services are the major classes of base rate (non-energy) inputs used by gas and electric utilities. These are capital-intensive businesses, so the heaviest weights are placed on the capital subindexes.

Productivity Indexes

The Basic Idea A productivity index is the ratio of an output quantity (aka scale) index ("*Outputs*") to an input quantity index.

$$\textit{Productivity} = \frac{\textit{Outputs}}{\textit{Inputs}}. \qquad [A2]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Some productivity indexes measure productivity *trends*. The growth of a productivity trend index is the difference between the growth of the output and input quantity indexes.[48]

$$\textit{growth Productivity} = \textit{growth Outputs} - \textit{growth Inputs}. \qquad [A3]$$

[48] This result holds true for particular kinds of growth rates.

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile for various reasons that include fluctuations in output and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity index measures productivity in the use of multiple inputs. These are sometimes call *total* factor productivity indexes even though they rarely encompass all inputs. Some indexes measure productivity in the use of a single input class such as labor. These indexes are sometimes called *partial* factor productivity ("PFP") indexes.

Output Indexes The output (quantity) index of a firm summarizes growth in its outputs or operating scale. If the index is multidimensional, growth in each output dimension that is itemized is measured by a sub-index, and growth in the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output growth on *cost.*[49] In that event, the index should be constructed from one or more output (aka scale) variables that measure dimensions of the "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts.

The sensitivity of cost to a small change in the value of an output or any other business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[50] An MFP index calculated using a cost-based output index ("$Outputs^C$") will be denoted as MFP^C.

[49] Another possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of *revenue*.

[50] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

$$growth\ MFP^{C} = growth\ Outputs^{C} - growth\ Inputs. \qquad [A4]$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[51] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

A second important source of productivity growth is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required if cost nonetheless tends to grow less rapidly than output. Increased capacity utilization and incremental scale economies will typically be lower the slower is output growth.[52]

A third important productivity growth driver is changes in the miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. An example for a power transmitter is system undergrounding. To the extent that growth of a service territory's urban core(s) produce more undergrounding of transmission facilities, cost surges and MFP growth slows.

System age can drive productivity growth in the short and medium term. Productivity growth tends to be greater to the extent that the capital stock is large relative to the need to replace plant that is nearing retirement age. If a utility requires unusually high replacement capital expenditures ("capex"), capital productivity growth can be unusually slow. The utility is, effectively, replacing depreciated older facilities with newer facilities that will last for many years and may be sized to accommodate future demand growth but are for these reasons more expensive.

Productivity growth is also driven by changes in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase

[51] The seminal paper on this topic is Denny, Fuss and Waverman, *op. cit.*

[52] Incremental scale economies may also depend on the current scale of an enterprise. For example, larger utilities may be able to achieve smaller incremental scale economies.

to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency.

Our analysis suggests that productivity growth can be different between utilities, and over time for the same utility, for reasons that are beyond their control. For example, a utility with unusually slow output growth and an unusually high number of assets needing replacement can have unusually slow productivity growth.

Use of Index Research in Regulation

Revenue Cap Indexes

Cost theory and index logic support the design of revenue cap indexes. The following basic result of cost theory is useful.

$$growth\ Cost = growth\ Input\ Prices - growth\ MFP^{C} + growth\ Outputs^{C}.\text{[53]} \qquad [A5]$$

The growth in the cost of a utility is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index.

Assuming that growth in the RCI should track growth in the cost of the typical utility, this result provides the basis for a revenue cap index of general form:

$$growth\ Revenue^{Allowed} = growth\ Input\ Prices - X + growth\ Scale^{C}_{Utility} \qquad [A6a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + Stretch. \qquad [A6b]$$

Here $Scale^{C}_{Utility}$ is an index of growth in the operating scale of the subject utility. X, the "X factor," reflects the base MFP^C growth trend ("$\overline{MFP}^{C}$") of the industry and a stretch factor. The base MFP^C growth trend is typically the trend in the MFP^C of the regional or national utility industry. Notably, a consistent cost-based scale index should be used in the supportive MFP research. Since the X factor

[53] An alternative basis for a revenue adjustment index can be found in index logic. Recall from relation [A1] that the growth in the cost of an enterprise is the sum of the growth in an appropriately designed input price index and input quantity index. Then,

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices + growth\ Scale^{C} - (growth\ Scale^{C} - growth\ Input\ Quantities) \\ &= growth\ Input\ Prices - growth\ MFP^{C} + growth\ Scale^{C} \end{aligned}$$

often includes a stretch factor in approved MRPs, it is sometimes said that the productivity research has the goal of "calibrating" (rather than solely determining) X.

For gas and electric power distributors, the number of customers served is a sensible scale escalator for a revenue adjustment index. The customers variable typically has the highest estimated cost elasticity amongst the scale variables considered in econometric research on the cost of energy distributors. A scale escalator that includes volumes and/or peak demand as scale variables diminishes a utility's incentive to promote DSM. This is an argument for excluding these variables from a revenue adjustment index scale escalator for a distributor.

The number of customers can replace $Scale^{C}_{Utility}$ in relation [A6a], with the following result:

$$growth\ Revenue^{Allowed} = growth\ Input\ Prices_{Industry} - X + growth\ Customers_{Utility} \qquad [A7a]$$

$$X = \overline{MFP}^{N}_{Industry} + Stretch.^{54} \qquad [A7b]$$

where $\overline{MFP}^{N}$ is the trend in an MFP index that uses the number of customers to measure output.

In power transmission no single scale variable is dominant. A multidimensional scale index with weights based on econometric research on transmission cost is therefore more appropriate.

Scale Escalators

Revenue adjustment indexes do not always include explicit scale escalators. A revenue adjustment index of general form

$$growth\ Revenue^{Allowed} = growth\ GDP\ IPI - X \qquad [A8a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + Stretch.$$

is equivalent to the following:

$$growth\ Revenue^{Allowed} = growth\ GDP\ IPI - X + growth\ Scale_{Utility} \qquad [A8b]$$

[54] An equivalent formula is:
$growth\ Revenue^{Allowed} - growth\ Customers = growth\ (Revenue^{Allowed}/Customer) = growth\ Input\ Prices - X$.
This is sometimes called a "revenue per customer" index.

where

$$X = \overline{MFP}^{C}_{Industry} + Expected(growth\ Scale_{Utility}) + Stretch. \qquad [A8c]$$

It can be seen that if the MRP does not otherwise compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor. The value of this implicit stretch factor will be larger the more rapid is the utility's expected scale index growth.

A.2 Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost ("CK") specification is critical in research on the transmission input price and productivity trends of utilities because the technology of transmission is capital intensive. The annual cost of capital includes depreciation expenses, a return on investment, and some taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in research on the costs and input price and productivity trends of utilities. These approaches permit the decomposition of capital cost into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

$$CK = WK \cdot XK. \qquad [A9]$$[55]

The growth rate of capital cost then equals the sum of the growth rates of the capital price and quantity indexes.

In U.S. electric utility research, capital quantity indexes are typically constructed by deflating the value of gross plant additions using a Handy Whitman electric utility construction cost index and

[55] In rigorous statistical cost research, it is often assumed that a capital good provides a stream of services over some period of time (the "service life" of the asset). The capital *quantity* index measures this flow, while the capital *price* index measures the trend in the simulated price of renting a unit of capital service. The design of the capital service price index is consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services.

subjecting the resultant quantity estimates to a mechanistic decay specification. Capital prices are calculated from these same construction cost indexes and from data on the rate of return on capital.[56]

Alternative Monetary Approaches

Several monetary methods for measuring capital cost have been established. A key issue in the choice between these methods is the pattern of decay in the quantity of capital from the plant additions that are made each year.[57] Another issue is whether plant is valued in historic or replacement dollars. Here are brief descriptions of the three monetary methods that have been most commonly used in the design of rate and revenue adjustment indexes.

1. Geometric Decay ("GD"). Under the GD method, the capital quantity is treated as the flow of services from plant additions in a given year. The flow is assumed to decline at a constant rate over time. Plant is typically valued in replacement dollars. Cost is usually computed net of capital gains.

   A GD capital quantity index is typically combined with a consistent GD capital price that simulates the price for capital services in a competitive rental market in which the capital stocks of suppliers experience GD. This price is driven by trends in construction costs and the rate of return on capital.

2. One-Hoss-Shay ("OHS"). Under the OHS method, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. However, in energy utility research this constant flow assumption has, due to data limitations, been applied to the total plant additions for groups of assets that have varied service lives. Plant is once again valued at replacement cost and cost is computed net of capital gains. As with GD, it is common to use a capital service price that is consistent with the OHS assumption.

[56] If taxes are included in the study, capital prices are also a function of tax rates.

[57] Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and technological obsolescence. The pattern of decay in assets over time is sometimes called the age-efficiency profile.

3. Cost of Service ("COS"). The GD and OHS approaches for calculating capital cost use assumptions that are quite different from those used to calculate capital cost under traditional COS ratemaking.[58] Replacement valuation of plant, capital gains, and use of capital service prices can all give rise to volatile GD and OHS capital costs and prices. The derivation of a revenue adjustment index using index logic does not require a service price treatment of the capital price.

   An alternative COS approach to measuring capital cost has been developed by PEG that is so-called because it is based on the straight-line depreciation and historical plant valuations, techniques used in utility capital cost accounting. Capital cost can still be decomposed into a price and a quantity index, but the capital price cannot be represented as a capital service price. The price and quantity index formulae are complicated, making them more difficult to code and review. However, capital prices are less volatile.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. When calculating capital quantities using a monetary method, it is therefore customary to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized decay specification for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For the earlier years that are pertinent in these calculations the desired gross plant addition data are frequently unavailable. It is then customary to take the total value of plant, with its diverse vintages, at the end of this limited-data period and to estimate the quantity of capital that it reflects using construction cost indexes from earlier years and assumptions about the historical plant addition pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

[58] The OHS assumptions are more markedly different.

Appendix B: Additional Information on Research Methods

B.1 Technical Details of PEG's Empirical Research

This section of Appendix B contains more technical details of our empirical research. We first discuss our input quantity and productivity indexes, respectively. We then address our methods for calculating input price inflation and capital cost.

Input Quantity Indexes

The growth rate of a summary (multidimensional) input quantity index is defined by a formula that involves subindexes measuring growth in the quantities of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

We have constructed summary OM&A, capital, and multifactor input quantity indexes. Each summary input quantity index is of chain-weighted Törnqvist form.[59] This means that its annual growth rate is determined by the following general formula:

$$\ln\left(Inputs_t / Inputs_{t-1} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(X_{j,t} / X_{j,t-1} \right). \qquad \text{[B1]}$$

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex value for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the natural logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

[59] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).

Productivity Growth Rates and Trends

The annual growth rate in each productivity index is given by the formula

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Outputs_t}{Outputs_{t-1}}\right) - \ln\left(\frac{Inputs_t}{Inputs_{t-1}}\right). \qquad [B2]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Input Price Indexes

The growth rate of an input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

The multifactor input price index used in the econometric total cost model was of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula. For any asset category *j*,

$$\ln\left({}^{Input\ Prices_t}/_{Input\ Prices_{t-1}}\right) = \sum_j \quad \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1}\right) \cdot \ln\left({}^{W_{j,t}}/_{W_{j,t-1}}\right). \qquad [B3]$$

Here in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

$Sc_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Capital Cost and Quantity Specification

A monetary approach was used to measure the capital cost of each utility. Recall from Appendix section A.2 that under this approach capital cost is the product of a capital quantity index and a capital price index.

$$CK = WKS \cdot XK.$$

Geometric decay was assumed in the construction of both of these indexes.

Data previously processed by PEG permitted us to use 1964 as the benchmark year for the U.S. capital cost and quantity calculations. The value of each capital quantity index for each U.S. utility in 1964 depends on the net ("book") value of its transmission and general plant as reported in FERC Form 1. We estimated the benchmark year quantities of capital by dividing these values, respectively, by triangularized weighted averages of 52 consecutive values of a regional Handy Whitman Index of power transmission construction cost and 18 values of a regional Handy Whitman Index of reinforced concrete building construction cost for periods ending in the benchmark year. A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

The following GD formula was used to compute values of each capital quantity index in subsequent years. For any asset category *j*,

$$XK_{j,t}=(1-d)\cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [B4]$$

Here, the parameter *d* is the economic depreciation rate and VI_t is the value of gross additions to utility plant. The assumed 52-year average service life for transmission plant, 18-year average service life for general plant, 1.65 declining balance rate for equipment, and 0.91 declining balance rate for structures were used to set *d*.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_{j,t}= d\cdot WKA_{j,t} + r_t\cdot WKA_{j,t-1}. \qquad [B5]$$

The first term corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. We decided not to include a capital gains term in the service price formula because this simplifies the analysis and has been a common practice in past OEB IR proceedings. The need for a capital gains term is reduced by the fact that the study does not include taxes. Were taxes included, the removal of capital gains would place undue weight on capital cost in total cost benchmarking appraisals.

B.2 Econometric Research Methods

This section of Appendix B provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods.

Form of the Econometric Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, double log, and translog. Here is a simple example of a *linear* cost model:

$$C_{h,t} = a_0 + a_1 \cdot L_{h,t} + a_2 \cdot D_{h,t}. \qquad [B6]$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t}. \qquad [B7]$$

Here, for each company h, $C_{h,t}$ is cost, L is the length of transmission lines and D is ratcheted peak demand.

The double log model is so-called because the right- and left-hand side variables in the equation are all logged.[60] This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 indicates the percentage change in cost resulting from 1% growth in the length of transmission lines. Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\ln C_{h,t} = a_o + a_1 \cdot \ln L_{h,t} + a_2 \cdot \ln D_{h,t} + a_3 \cdot \ln L_{h,t} \cdot \ln L_{h,t} + a_4 \cdot \ln D_{h,t} \cdot \ln D_{h,t} + a_5 \cdot \ln L_{h,t} \cdot \ln D_{h,t} \qquad [B8]$$

This form differs from the double log form in the addition of quadratic and interaction terms. These are sometimes called second-order terms. Quadratic terms like $\ln D_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of

[60] i.e., the variable is used in the equation in natural logarithmic form, as ln(X) instead of X.

cost with respect to a scale variable may, for example, be lower for a small utility than for a large utility. Interaction terms like ln $L_{h,t} \cdot \ln D_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment.

In our econometric work for this proceeding, we have chosen a functional form that has second-order terms only for the two scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All of the second-order terms in our model had statistically significant parameter estimates.

Econometric Model Estimation

A variety of parameter estimation procedures are used by econometricians. The appropriateness of each procedure depends on the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated and realistic error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic, meaning that they vary across companies. Variances can, for example, be larger for companies with large operating scale. In this study we used GLS escalators that corrected for autocorrelation and groupwise heteroskedasticity.

Note, finally, that the model specification was determined using data for all sampled companies. However, estimation of parameters and appropriate standard errors for the cost model actually used for benchmarking required that the utility of interest be dropped from the sample. The parameter estimates used in developing the cost model and reported in Table 2 above therefore vary slightly from those in the models used for benchmarking.

B.3 Summarizing Methodological Changes

The following changes have been made in our research methodology since the Hydro One SSM report.

- Certain errors that were made in the study supporting our Hydro One SSM evidence have been corrected as discussed in our Hydro One SSM interrogatory response found in Exhibit L1 Tab 1 Schedule 6.
- We excluded capital gains from the calculation of capital costs and prices. This increased the importance of capital cost performance in the productivity and benchmarking results.
- Our econometric model estimation procedure now corrects for autocorrelation as well as groupwise heteroscedasticity.
- We used Statistics Canada's implicit price deflator for the assets of the Canadian utility sector rather than the Ontario utilities sector. This grew more rapidly than the IPD for Ontario utility assets.
- We upgraded our estimates of depreciation rates. We made small improvements to the depreciation rate calculations by employing separate depreciation treatment of structures vs. equipment not previously done by either PSE or PEG. We also used service lives more consistent with the HON study used by PSE than we had earlier.[61]
- We removed several companies from the sample. Three were removed because the transmission line mile data had large changes due to reclassifications between transmission

[61] The first issue is that the declining balance parameter used by PSE is for equipment and not structures. The second is that the service life used by PSE was drawn from a Hydro One depreciation study for all plant and not just for transmission plant. The first problem was addressed by classifying each account as either structures or equipment and calculating a depreciation rate by asset type with the appropriate declining balance parameter. The overall depreciation rate was calculated as a plant-weighted average of the individual depreciation rates. This was done for transmission and general plant separately. The second issue stems from PEG previously applying the overall service life to transmission calculations. This was corrected by the foregoing calculation and by using the separate Hydro One average service lives for transmission and general in the triangularized-weighted average calculations in the benchmark year.

and distribution. One company was removed due to the cost of a large joint venture being assigned to rents.[62]

- We used data provided by Hydro One in response to an interrogatory to reduce the company's OM&A cost to be consistent with the PEG definition of cost for U.S. transmitters.

B.4 Calculation of the Supplemental Stretch Factor

Introduction and Summary

Supplemental capital funding has become an increasingly important issue in Ontario as the OEB tries to balance a desire for strong performance incentives, fair outcomes for customers, and low regulatory cost against the occasional need for high but prudent capital expenditures that cannot be funded by price and revenue cap indexes alone. For the 4GIRM, the Board sanctioned incremental and advanced capital modules with materiality thresholds and dead zones that effectively mark down the plant additions eligible for extra revenue. Markdowns like these can strengthen utility performance incentives, trim regulatory cost, and share IR benefits with customers more fairly.

Custom IR plans approved by the OEB to date typically supplement revenue by adding a C factor to the rate or revenue cap index formula. In EB-2017-0049 the Board approved a supplemental stretch factor for Hydro One (which we will call an S-factor) which lowered Hydro One Distribution's proposed C-factor. However, the approved S-factor of 0.15% may not provide the same markdown as the materiality thresholds in an ICM or ACM.

We have endeavored to calculate the ACM-equivalent S-factor in 3 steps.

Step 1: Calculate the percentage of proposed gross plant additions that would not be funded by an ACM were it to apply to Hydro One Transmission.

Step 2: Calculate the percentage of new (additions-related) capital cost that is not funded in Custom-IR according to the I – X and S factors.

[62] The three companies excluded for reclassifications of assets are Black Hills, PPL Electric Utilities, and Public Service of New Hampshire. Each showed large transfers of transmission plant that were associated with large changed in reported transmission line miles. The company excluded for rents was Nevada Power. Accounting for the 25% jointly owned One Nevada line cost was corrupting OM&A cost by the inclusion of large amounts of capital cost inconsistent with the rest of the study. The exclusion of this company allowed us to include rents in the cost calculations and make the work more consistent with the PSE study.

Step 3: Equate the two and solve for S. Plug S into the C-factor formula to obtain the adjusted C-factor.

The impact of our calculations on Hydro One's proposed C-factor is shown in Table B1. The calculations of the C-factor follow the familiar formula, $C = C_n - S_{cap} \cdot (I + S)$.

Table B1

Resultant C-factor under different S-factors

C Factor Component (%)	Variable	2021	2022	Average
Percentage of Total RR in previous year	C_n	5.18	4.68	4.93
Capital Cost Share	S_{cap}	78.42%	79.16%	78.79%
I	I	1.40	1.40	1.40
S (HON-Tx Proposed)	S_1	0.00	0.00	0.00
S (HON Dx IRM)	S_2	0.15	0.15	0.15
S (ACM Equivalent)	S_3	0.31	0.53	0.42
C Factor: HON-Tx Proposed	$C_1=C_n-S_{cap}*(I+S_1)$	4.09	3.59	3.84
C Factor: S=0.15	$C_2=C_n-S_{cap}*(I+S_2)$	3.96	3.46	3.71
C Factor: ACM Equivalent	$C_3=C_n-S_{cap}*(I+S_3)$	3.84	3.16	3.50

As can be seen, the ACM-equivalent S-factor for Hydro One Transmission averages 0.42%, which is higher than that which the OEB approved in the recent Hydro One Dx Custom IR decision (EB-2017-0049). The average resultant C-factor is 3.50%, compared to Hydro One's proposed 3.84%.

In the balance of this Appendix section, we first present a glossary of terms and then discuss our calculations step by step.

Glossary of Terms and Key Identities

C = C factor

CK = capital cost

CK^{new} = capital cost of new additions

CKD = depreciation expenses

CKR = return on rate base

g = actual billing determinant growth (assumed to equal G for simplicity)

R = total revenue

RK = capital revenue

RK^+ = supplemental capital revenue

RKR = return on rate base revenue requirement

ROM = OM&A revenue

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

r = rate of return on rate base

VKA = value of proposed gross plant additions

$VKA^{eligibile}$ = value of proposed gross plant additions eligible for extra revenue

VKA^{funded} = value of gross plant additions funded by both price cap mechanism and any supplemental capital revenue

$VKA^{ineligible}$ = value of proposed gross plant additions ineligible for supplemental revenue

$VKA^{price\ cap}$ = value of gross plant additions funded by the price cap mechanism

M = markdown factor used in the 4GIRM Threshold Value formula

S = extra stretch factor in the C factor formula, like that approved in EB-2017-0049

Sc_K = capital cost share

$Sc_{OM\&A}$ = OM&A cost share

TC = total cost

I = annual price inflation

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

Several simplifying assumptions are made throughout the analysis for ease of review and presentation. Costs are assumed equal to revenues in the base year and retirements are ignored.

Here are a few identities to keep in mind for the analysis:

$$VKA = VKA^{eligible} + VKA^{ineligible}$$

$$VKA^{funded} = VKA^{price\ cap} + VKA^{eligible}$$

Step 1: Calculate 4GIRM and the Supplemental Capital Threshold Value

When a utility is operating under 4GIRM, the revenue for costs addressed by the price cap index in the first indexing year is determined by the following formula:

$$R_1 = ROM_1 + RK_1 = R_0 \cdot (1 + I - X) \cdot (1 + g) + RK_1^{+}. \quad [B9]$$

Revenue in year 1 grows with billing determinants and the approved I-X price cap index and there may also be some supplemental capital revenue ("RK_1^{+}"). The total capital revenue requirement can be decomposed into revenue required for depreciation, the return on rate base, and taxes. However, the rationale for the ACM/ICM materiality threshold is based only on the return on rate base component of capital cost ("*CKR*"), so we consider only this and the corresponding revenue ("*RKR*") in the following discussion.

Consider now the difference between *CKR* and *RKR* in the first year of an IRM. The former is the proforma return on rate base capital cost incurred by the company and the latter is the return on rate base capital revenue provided by the price cap mechanism and any supplemental capital revenue. The formulas are

$$CKR_1 = r \cdot VK_1^{net} = r \cdot (VK_0^{net} + VKA_1 - CKD_1) \quad [B10]$$

and, in the absence of supplemental revenue,

$$RKR_1 = r \cdot VK_0^{net} \cdot (1 + I - X) \cdot (1 + g). \quad [B11]$$

Here $VK_1^{net} = VK_0^{net} + VKA_1 - CKD_0$ because the rate base in year 0 equals the prior year's rate base plus the value of additions made in the current year minus annual depreciation.

In the absence of RK^{+}, all VKA_1 above the threshold value would be underfunded and cost would exceed revenue, i.e.,

$$CKR_1 > RKR_1. \quad [B12]$$

Substituting [B10] and [B11] into [B12] yields the following relation:

$$r \cdot (VK_0^{net} + VKA_1 - CKD_1) > r \cdot \left(VK_0^{net} \cdot (1 + I - X) \cdot (1 + g)\right). \quad [B13]$$

Rearranging, distributing, and collecting terms then gives

$$VKA_1 > CKD_1 + VK_0^{net} \cdot \left(g + (I - X)\right) \cdot (1 + g). \quad [B14]$$

Inspecting the results, it can be seen that part of the funding for plant additions comes from the depreciation of old plant.

The "Threshold Value" formula in the ACM/ICM materiality threshold for the first indexing year is obtained by dividing both sides of [B14] by depreciation and appending a "markdown factor", $M > 0$, to the right-hand-side.

Threshold Value Formula

$$\frac{VKA_1}{CKD_0} > 1 + \frac{VK_0^{net}}{CKD_0} \cdot \{[g + (I - X)] \cdot (1 + g)\} + M \qquad [B15]$$

This formula was adopted by the OEB in EB-2014-0219. Note that depreciation is in the base year (CKD_0) in the OEB's approved formula.

The markdown factor allows the OEB to set the minimum amount by which capital expenditures must exceed the funded amount before any additions become eligible for extra capital revenue. The OEB initially set *M* at 20% and later lowered it to 10%. The value of additions that are ineligible for supplemental revenue are then given by the following formula. Since Hydro One is under a revenue cap index, assume *g* = 0.

$$VKA_1^{ineligible} = CKD_0 + VK_0^{net} \cdot (I - X) + M \cdot CKD_0 \,. \qquad [B16]$$

Since $VKA = VKA^{eligible} + VKA^{ineligible}$, it follows that

$$VKA^{eligible} = VKA - VKA^{ineligible} \,. \qquad [B17]$$

Plugging [B16] into [B17], the portion of gross plant additions eligible for supplemental capital revenue is then

$$VKA_1^{eligible} = VKA_1 - [CKD_0 + VK_0^{net} \cdot (I - X) + CKD_0 \cdot \mathrm{M}] \qquad [B18]$$

$$= VKA_1 - [(1 + M) \cdot CKD_0 + VK_0^{net} \cdot (I - X)]. \qquad [B19]$$

Note here that the markdown factor *M* only applies to base year depreciation and not to the other source of funding as a result of the OEB's chosen Threshold Value formula. *M* could reasonably be applied to the second source of funding as well. If the utility's plant additions are close to qualifying for extra revenue, it will be incentivized to bolster its proposed additions so as to obtain supplemental revenue. Bunching of plant additions can help with this.

The full funding for gross plant additions in indexing year *1* is then the sum of gross plant additions provided by the price cap and those eligible for supplemental revenue.

$$VKA_1^{funded} = CKD_0 + VK_0^{net} \cdot [(1 + I - X) - 1] + VKA_1^{eligible} \,. \qquad \text{[B20]}$$

By substituting [B19] into [B20] and carrying out simple algebra, it can be shown that

$$VKA_1^{funded} = VKA_1 - M \cdot CKD_0. \qquad \text{[B21]}$$

The share of VKA_1 that is *not* funded under 4GIRM in year *1* is then

$$\frac{VKA_1 - VKA_1^{funded}}{VKA_1} = \frac{VKA_1 - (VKA_1 - \mathrm{M} \cdot \mathrm{CKD_0})}{VKA_1} \qquad \text{[B22]}$$

$$= \frac{M \cdot CKD_0}{VKA_1}. \qquad \text{[B23]}$$

As can be seen from [B23], the percentage of gross plant additions that would not be funded in the first year of an ACM plan is the ratio of *M* times base year depreciation to gross plant additions in year 1. The percentage markdown will be less to the extent that *VKA* exceeds the materiality threshold. It can be shown with more algebra that the markdown formula in the second year is the same as the first year but with VKA_2 instead of VKA_1.

We calculate this percentage for Hydro One in each year of its proposed IR plan in Table B2. Were this mechanism used to determine Hydro One's extra capital revenue instead of the proposed C factor, it can be seen that the underfunding would be roughly 3.63% of proposed plant additions in the first indexing year and 3.65% of proposed plant additions in the second year.

Table B2

Calculating the ACM Markdown

Variable Name	Plant Additions Markdown	Base Year 2020	Year 1 2021	Year 2 2022
M	M Factor		10%	10%
CKD_0	Base Year Depreciation ($M)	474.60	--	--
VKA	Gross Plant Additions ($M)		1,297.70	1,293.00
	Markdown = $M \cdot CKD_0/VKA_t$		3.66%	3.67%

Step 2: Calculate the Markdown in the C Factor in Custom-IR

Under a C factor mechanism like that approved for Hydro One's distributor services, growth in revenue for inputs that are addressed by indexing conforms to the following formula.[63] In these calculations, we assume that base year revenue equals base year costs ($RK_0 = CK_0$). From growth rate math, it can be shown that

$$growth\ R = Sc_K \cdot growth\ RK + Sc_{OM\&A} \cdot growth\ ROM \qquad [B24]$$

$$= Sc_K \cdot [(I - X) + (growth\ CK - I - S)] + Sc_{OM\&A} \cdot (I - X) \qquad [B25]$$

$$= Sc_K \cdot [growth\ CK - (X + S)] + Sc_{OM\&A} \cdot (I - X). \qquad [B26]$$

Since the X factor is the sum of the base productivity trend and a stretch factor, capital revenue growth is reduced by the base productivity trend, but this is currently 0 in Ontario regulation. Hence the two stretch factor terms are the only basis for a capital revenue growth markdown. The stretch factor component of *X* ranges from 0 to 0.6% in Ontario and reflects statistical total cost benchmarking results.

Now, capital revenue in year 1 is defined by

$$RK_1 = RK_0 \cdot (1 + growth\ RK) \qquad [B27]$$

$$= RK_0 + RK_0 \cdot growth\ RK \qquad [B28]$$

$$= RK_0 + RK_0 \cdot [growth\ CK - (X + S)] \qquad [B29]$$

$$= RK_0 + RK_0 \cdot \left[\frac{\mathrm{CK}_1 - \mathrm{CK}_0}{\mathrm{CK}_0} - (X + S)\right] \qquad [B30]$$

$$= RK_0 + RK_0 \cdot \left[\frac{CK_1 - RK_0}{RK_0} - (X + S)\right] \qquad [B31]$$

$$= CK_1 - RK_0 \cdot (X + S). \qquad [B32]$$

[63] We are, effectively, abstracting from variance accounts and Z factors.

NB: We can derive the C-factor using [B25] but it is not necessary for this step. From [B25], since the sum of sc_K and $sc_{OM\&A}$ equals 1 by definition, we have

$$\begin{aligned} growth\ R &= I - X + sc_K \cdot [growth\ CK - (I + S)] \\ &= I - X + \frac{CK_0}{TC_0} \cdot \left[\frac{CK_1 - CK_0}{CK_0} - (I + S)\right] \\ &= I - X + \left[\frac{CK_1 - CK_0}{TC_0} - \frac{CK_0}{TC_0} \cdot (I + S)\right] \\ &= I - X + C \end{aligned}$$

The share of capital cost from new plant additions ("CK_1^{New}") that is ineligible for supplemental revenue is then (invoking $RK_0 = CK_0$)

$$\frac{CK_1 - RK_1}{CK_1^{New}} = \frac{RK_0 \cdot (X + S)}{CK_1^{New}} \qquad [B33]$$

$$= \frac{CK_0 \cdot (X + S)}{CK_1^{New}}. \qquad [B34]$$

Capital revenue in year 2 is defined by

$$RK_2 = RK_1 \cdot (1 + growth\ RK) \qquad [B35]$$

$$= RK_1 + RK_1 \cdot growth\ RK \qquad [B36]$$

which, letting $RK_1 = CK_1 - RK_0 \cdot (X + S)$ from [B32] above,

$$= CK_1 - RK_0 \cdot (X + S) + (CK_1 - RK_0 \cdot (X + S)) \cdot [\text{growth } \mathrm{CK}_2 - (X + S)] \qquad [B37]$$

$$= CK_1 - RK_0 \cdot (X + S) + (CK_1 - RK_0 \cdot (X + S)) \cdot \left[\frac{\mathrm{CK}_2 - \mathrm{CK}_1}{\mathrm{CK}_1} - (X + S)\right] \qquad [B38]$$

$$= CK_1 - CK_0 \cdot (X + S) + [CK_1 - CK_0 \cdot (X + S)] \cdot \left[\frac{\mathrm{CK}_2 - \mathrm{CK}_1}{\mathrm{CK}_1} - (X + S)\right] \qquad [B39]$$

$$= CK_2 - CK_1 \cdot (X + S) - \big(CK_0 \cdot (X + S)\big) \cdot \left(\frac{CK_2}{CK_1} - (X + S)\right). \qquad [B40]$$

The percentage of CK_2^{New} that is not eligible for supplemental revenue is then

$$\frac{CK_2 - RK_2}{CK_2^{New}}$$

which can be shown to equal

$$\frac{CK_1 * (X+S) + CK_0 * (X+S) * \left(\frac{CK_2}{CK_1}\right) - CK_0 * (X+S)^2}{CK_2^{New}}.$$

Table B3 presents the capital cost markdown results as a share of new capital cost.

Table B3

Capital Cost Markdown

Variable Name	Capital Cost Markdown	Base Year 2020	Year 1 2021	Year 2 2022
CK	Capital Cost ($M)	1,298.00	1,384.70	1,467.40
CK^{NEW}	Capital Cost of New Additions ($M)	--	111.42	230.89
	Markdown (Depends on X and S)		11.65·(X+S)	6.93·(X+S)-5.62·(X+S)^2

Step 3: Solve for *S* and Calculate the ACM-Equivalent C Factor

It is reasonable for the C factor to produce underfunding of new capital cost which is no less than the underfunding of the value of gross plant additions in 4GIRM. In Step 3, we calibrate *C* to produce such a markdown for Hydro One. To accomplish this, we solve for the value of *S* which equates [B23] and [B33]. In other words, solve for *S* such that the following result holds each year.

$$\frac{VKA_t - VKA_t^{funded}}{VKA_t} = \frac{CK_t - RK_t}{CK_t}.$$

We showed in Step 1 the percentage markdown on 4GIRM gross plant additions under a 4GIRM formula (the left-hand side) and we showed in Step 2 the percentage markdown on capital cost multiplied by (*X+S*) (the right-hand side). Table B4 shows the resultant S factors from equating the two. The S factor would be 0.31% in 2021 and 0.53% in 2022, averaging 0.42% over the two years. Thus, the S-factor that achieves parity with an ACM-style capital markdown is higher than the 0.15% S factor approved in the Hydro One Distribution IRM.

Table B4

Calculating the ACM-Equivalent S Factor for Capital Cost

Variable Name		Base Year 2020	Year 1 2021	Year 2 2022
	Step 1: Plant Additions Markdown			
M	M Factor		10%	10%
CKD_0	Base Year Depreciation ($M)	474.60	--	--
VKA	Gross Plant Additions ($M)		1,297.70	1,293.00
[A]	Markdown = $M \cdot CKD_0/VKA_t$		3.66%	3.67%
	Step 2: Capital Cost Markdown			
CK	Capital Cost ($M)	1,298.00	1,384.70	1,467.40
CK^{NEW}	Capital Cost of New Additions ($M)	--	111.42	230.89
[B]	Markdown (Depends on X and S)		$11.65 \cdot (X+S)$	$6.93 \cdot (X+S) - 5.62 \cdot (X+S)^2$
	Step 3: Solve for S			
	Set [A]=[B] and solve for S			
	S-factor (assume X=0)		0.31%	0.53%

Appendix C: Federal Regulation of U.S. Power Transmission

To appraise the relevance of statistical cost research using U.S. transmission data for the situation of Hydro One, it is important to understand some key factors of the U.S. transmitter operating environment. Regulation of U.S. power transmission rates is undertaken today chiefly by the FERC. Transmitter productivity has been greatly affected by FERC regulation and by state and federal policies.

C.1 Unbundling Transmission Service

Transmission regulation prior to the mid-1990s reflected the vertically-integrated structure of most investor-owned electric utilities in that era. These utilities typically owned both the transmission and distribution systems in the areas they served and obtained most of their power supplies from their own generation facilities. There were fewer bulk power purchases and independent power producers using transmission services than there are today.

Wholesale customers (e.g., municipal utilities) could obtain bundled generation and transmission services from adjacent utilities by negotiating contracts with them. Power was sometimes purchased from a third party. If the contract path for such a purchase passed over multiple transmission systems the customer might have to pay multiple transmitters for service, a phenomenon called "pancaked rates". Disputes over wholesale contracts for the purchase and transmission of power could be brought to the FERC. Utilities sometimes had the ability to discriminate between their customers regarding the terms of transmission service.

Starting in the 1970s, federal policy has increasingly encouraged 3rd party generators and the development of more robust bulk power markets. This increased the demand for public, non-discriminatory tariffs for wholesale transmission service. In 1996, FERC Order 888 required transmitters to provide service under open access transmission tariffs ("OATTs"). To ensure that service was provided on a non-discriminatory basis, the FERC also ordered transmitters to establish an information network to provide network information to transmission customers and to obtain their native load transmission service solely using the OATT and the publicly available information network. Third parties were provided the option to procure the same types of service at the same quality levels as the transmitter's native load. Many details of the resultant functional unbundling and the information service for transmission customers were addressed in FERC Order 889.

Bulk power markets were also expanded by restructuring retail markets in many American states. Retail customers in these states had a greater choice of power suppliers. Many large industrial customers became bulk power market participants.

C.2 Formula Rates

Rates for jurisdictional transmission services can be set by the FERC in periodic rate cases. Transmitters also have the option to request formula rate mechanisms, wherein rates are reset annually to reflect the changing cost of their service. Formula rates may rely on a transmitter's historical cost and revenue data or on forward-looking cost and revenue data with a subsequent true up of forecasts to actual values.

Formula rates have been used at the FERC and its predecessor, the Federal Power Commission, to regulate interstate services of gas and electric utilities since at least 1950. Early FERC rationales for using formula rates included the following.[64]

- Establishment of rates for a new utility;
- Establishment of rates for the transaction of one utility with an affiliated utility; and
- Economies in regulatory cost.

Regulatory cost economies are a major consideration for a commission with jurisdiction over the transmission services of more than 100 electric utilities and dozens of interstate oil and gas pipelines.

Use of formula rates by the FERC was encouraged in the 1970s and early 1980s by rapid input price inflation. Despite slower inflation in more recent years, the FERC's use of formula rates has grown in the power transmission industry. Growing use of OATTs greatly increased the need to set rates for transmission services by some means. Formula rates were also encouraged by national energy policies such as the Energy Policy Act of 2005 which promoted transmission investment and increased attention to reliability. Early adopters of formula rates included midwestern and New England utilities and the Southern Company. Many of the formula rate mechanisms approved by the FERC have been the product of settlements.

[64] A useful discussion of early precedents for formula rates at the FERC can be found in a March 1976 administrative law judge decision in Docket No. RP75-97 for Hampshire Gas.

At the 2004 start date of PSE's sample period about 15 of the 56 sampled U.S. transmitters in PSE's econometric sample operated under formula rates. By the 2016 end point of PSE's sample period fewer than 15 sampled transmitters *did not* operate under formula rates. PEG is not aware of any transmitters that abandoned formula rate plans during PSE's sample period. Thus, about half of the U.S. transmitters in the PSE sample received approval of formula rate plans during the PSE sample period.

C.3 ISOs and RTOs

As another means to promote development of bulk power markets and non-discriminatory transmission service, in 1996 the FERC encouraged electric utilities to transfer operation of their transmission systems to an independent system operator. In this arrangement, the transfer of control was voluntary and utilities retained ownership of their portions of the grid. ISOs have scheduled services, managed transmission facility maintenance, provided transmission system information to potential customers, ensured short-term grid reliability, and considered remedies for network constraints. ISO services must be provided under an OATT that is not discriminatory to any market participant. These tariffs recover the ISO's cost, which sometimes including the sizable charges of transmission owners for the use of their systems.

In a 1999 order, the FERC pushed for further structural change in the markets for transmission services by encouraging formation of RTOs. The FERC has higher requirements for RTO approval than for ISOs. For example, RTO tariffs must include the transmission owners' cost. RTOs also typically have a larger footprint, serving multiple states while some ISOs serves a single state or Canadian province.

Several ISOs were formed between 1996 and 2000. The FERC has approved applications for RTOs that serve much of the Northeast, East Central, and Great Plains regions of the U.S. The Midwest ISO (dba today as Midcontinent ISO) and PJM Interconnection were approved for RTO status in 2001, while the Southwest Power Pool and ISO New England became RTOs in 2004. ISOs that are not RTOs currently operate in some Canadian provinces, New York, Texas, and California.[65] Relatively few utilities in the southeastern and intermountain states are members of an ISO or RTO.[66] The charges of

[65] Texas transmitters in the Electricity Reliability Council of Texas are generally not subject to FERC regulation.

[66] In recent years, several South Central U.S. transmitters joined MISO.

transmission owners who are members of ISOs and RTOs may still be reset in periodic rate cases or formula rate plans.

C.4 Energy Policy Act of 2005

Beginning in the late 1970s, U.S. transmission capex trended downward in real terms. Part of this decline was due to low generation plant additions, particularly in the late 1990s. Other reasons for the decline in capex were difficulties in siting transmission lines. The grid did not always handle the demands placed on it by growing bulk power market transactions, and congestion costs occurred in some areas. The decline in capex eventually led to concerns by the FERC and other policymakers that transmitters were not sufficiently investing in their networks, thus jeopardizing the success of bulk power markets.

This is the context in which the Energy Policy Act of 2005 was passed. It affected transmission investment and many other aspects of transmitter operations. The Act gave the FERC authority to oversee transmission reliability. The FERC could sanction mandatory reliability standards and penalties. Development of these standards, now called Critical Infrastructure Protection standards, was largely delegated to the North American Electric Reliability Corporation ("NERC"). Numerous NERC Reliability Standards were approved by the FERC in 2007. These standards are intended to prevent reliability issues resulting from numerous sources including operation and maintenance of the system, resource adequacy, cybersecurity, and cooperation between operators.

Concerns about siting of transmission lines were somewhat mitigated by a provision allowing the federal government to designate "national interest electric transmission corridors" to mitigate areas of significant transmission congestion. This provision has proven to be somewhat controversial, as it is viewed as a federal intrusion into an issue that states have traditionally addressed. Nevertheless, it is likely that potential federal oversight of transmission siting encouraged state regulators to expedite transmission siting proceedings.

Concerns about transmission owner incentives were addressed by the addition of a mandate for the FERC to incentivize both transmission investments and participation in an RTO or ISO. The Energy Policy Act of 2005 required FERC to adopt a rule that would accomplish the following:

> ''(1) promote reliable and economically efficient transmission and generation of electricity **by promoting capital investment in the enlargement, improvement, maintenance, and operation**

of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;

''(2) **provide a return on equity that attracts new investment in transmission facilities** (including related transmission technologies);

''(3) **encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities**; and

''(4) allow recovery of—

> ''(A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215; and
>
> ''(B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216.[67]

In FERC Orders 679 and 679-A, released in 2006, the FERC adopted a wide range of incentives to encourage transmission investment. These incentives included the ability for a transmitter to include 100% of CWIP in rate base, ROE premiums for plant additions resulting from some projects, accelerated depreciation, full cost recovery for abandoned facilities and pre-operation costs, and cost tracking for individual projects. In addition, ROE premiums were permitted for transmitters who joined or remained in an RTO or ISO.

In this framework, a transmission operator would need to file an application and show that the requested incentives were appropriate. These applications could also be tied to a request by a transmitter to switch from a fixed rate adjusted only in a rate proceeding to a formula rate that is updated annually. Between 2006 and 2012, the FERC reviewed more than 80 applications for transmission incentives related to proposed projects.

[67] Energy Policy Act of 2005, Title XII, Sec. 1241 (b).

Appendix D: PEG Credentials

PEG is an economic consulting firm with headquarters in Madison, Wisconsin USA. We are a leading consultancy on incentive regulation and statistical research on the performance of electric and natural gas utilities. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given us a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the senior author and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared productivity research and testimony in more than 30 separate proceedings. Author of dozens of professional publications, Dr. Lowry has chaired numerous conferences on performance measurement and utility regulation. He recently coauthored two influential white papers on IR for Lawrence Berkeley National Laboratory. In the last five years, he has played a prominent role in IR proceedings in Alberta, British Columbia, Colorado, Hawaii, Minnesota, and Quebec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

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