Pacific Economics Group Research, LLC

December 19, 2013

MEMORANDUM TO ONTARIO ENERGY BOARD STAFF

On December 3, 2013, the Electricity Distribution Association (EDA) hosted a webinar for their members facilitated by staff from the distributor community, the Ontario Energy Board (the Board) and Pacific Economics Group Research (PEG). The objective of the webinar was to provide distributors with the tools needed to understand how their data are used in the empirical analyses. In addition to a step-by-step walkthrough of the benchmarking working papers, there was a demonstration of a benchmarking algorithm tool that each distributor can use to compare its forecasted costs with the approximate costs predicted for that distributor by the benchmarking model.

Prior to and at the webinar, distributors asked clarifying questions on how their data are used, the working papers, and the benchmarking algorithm. The purpose of this memorandum is to respond to several of those questions.

Smart Meter Capital Additions

Prior to the webinar, a data processing error was noticed in PEG's benchmarking database. This error applied to the smart meter capital additions that were added to distributors' capital stock in 2012. This error applies only to the 2012 year.

PEG has corrected the 2012 smart meter capital data, and the corrected datasets are provided on the Board's website at its link for the EB-2010-0379 consultations. PEG has quantified the impact of this correction on each distributor's benchmarking results. Details on the correction are provided in an Appendix to this Memorandum. In summary, the correction does not affect the stretch factor assignments of distributors; however, it does change the quantitative difference between actual and predicted cost for most distributors. Therefore, PEG has revised Table 17 in PEG's November 21, 2013 report entitled "Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board ("PEG's November 2013 Report"), to include the changes in rankings, and this revised report has also been posted on the Board's website.

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Clarification of Data Input Instructions for Benchmarking Algorithm

At the webinar, distributors asked a number of questions on the data that need to be input into the benchmarking algorithm. In response, PEG has modified some descriptions in the algorithm to remove ambiguity about what information distributors would need to input into the algorithm. In particular, PEG has clarified:

- The smart meter adjustment instructions in Sheets 3 and 4 of the algorithm;
- The specific HV and LV costs to be entered in Sheet 3 of the algorithm; and
- That total billed kWh should be entered in Sheet 2 of the algorithm.

The "Negative Capital Additions Flag"

Also at the webinar, PEG was asked to explain why Niagara Peninsula Energy (NPE) was flagged as having negative capital additions for benchmarking purposes in 2012. PEG offers the following explanation. In its empirical analyses, PEG estimated capital additions for distributors using year-over-year differences in each company's gross plant. For the purposes of PEG's TFP work, negative capital additions would have been computed for NPE in 2012 based on the differences in NPE's gross plant in 2012 and 2011.[1] PEG did not accept this result as plausible. Therefore, to avoid this result, PEG used the 2012 capital additions data reported by NPE in Section 2.1.5 of the Board's RRR for the TFP work. To maintain consistency between the TFP work and the benchmarking work, PEG used the same 2012 capital additions value for NPE in the benchmarking work.

PEG was also asked at the webinar to cross reference calculations in the "Benchmarking Results" sheet of the algorithm with the econometric research presented in PEG's November 2013 Report. In brief, the benchmarking results in the algorithm are derived using two sets of information:

1) the "cost drivers" estimated by PEG and presented in Table 16 of PEG's November 2013 Report; and
2) *projected* or *forecast* values for the distributor's own output and input price data, which the distributor enters on Sheet 2 of the algorithm.[2]

[1] As summarized in Table 5 of PEG's November 2013 report, PEG used different capital measures in its TFP and benchmarking work.

[2] Table 16 is titled "Econometric Coefficients: Cost Benchmarking." "Cost drivers" is another, less technical name for the "coefficients" estimated by PEG using econometric methods. In PEG's model, the cost drivers show how much a 1% change in a distributor's value for a cost driver variable is expected to increase the distributor's total electricity distribution cost. For example, for average line length (L), the estimated coefficient/cost driver is 0.2853; this means that, all else equal, a 1% increase in km of line over the 2002-2012 period would be expected to increase the distributor's cost by 0.2853%.

The algorithm multiplies the estimated cost drivers by projected values of the distributor's own outputs, input prices and business conditions to develop a 'predicted cost' for the company in the year specified by the distributor. This predicted cost appears on the predicted cost row in Sheet 5 of the algorithm. This cost prediction is compared to the Company's 'actual cost' forecast for the same year, which is calculated using forecast cost information that the distributor has entered on Sheets 3 and 4 of the algorithm. This actual cost appears on the actual cost row in Sheet 5.

The difference between actual and predicted costs is reflected in the percentage difference row in Sheet 5. This 'percentage difference' value is analogous to the value for the distributor in the 'Actual minus Predicted Cost' column in Table 17 of PEG's November 2013 Report. However, it should be noted that the algorithm presents forecast values for this difference using projected data in future years while Table 17 presents the actual percentage difference using actual observed data for the years 2010 through 2012.

It should also be noted that the algorithm uses the 'cost drivers' estimated in the econometric model filed, and posted on the Board website, with PEG's November 2013 Report. The 'cost drivers' (*i.e.* the coefficients for the input price, output and business condition variables) estimated by the econometric model filed with PEG's November 2013 Report will remain fixed from 2014 to 2018. That is, the econometric model will not be re-estimated during this time, and benchmarking results over the 2014 to 2018 period will be determined by:

1) adding one year of distributor and input price data to PEG's benchmarking database;
2) multiplying the existing cost driver estimates by new values of each distributor's input price, output, and business condition variable to produce an updated cost prediction for each distributor; and
3) comparing each updated cost prediction to each distributor's updated actual cost;
4) calculating the difference between actual and predicted cost for each distributor in percentage terms.

The Board will then determine stretch factor assignments by segmenting the resulting efficiency rankings based on the percentage difference between actual and predicted costs, as set out in its November 21, 2013 *Report of the Board Report of the Board on Rate setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*.

This approach furthers the Board's objective of creating strong performance incentives. On page 21 of its Report, the Board states that the distribution of stretch factors "…based on *today's sector performance* will shift as distributors improve their performance and (the Board) views this as a positive feature of the approach" (emphasis added). The November 2013 econometric model, reflecting the current cost performance of the Ontario electricity distribution industry, will be used to set stretch factors in every year that Price Cap IR is in place. This is analogous to fixing a benchmark using historical performance (*i.e.* the cost performance standard reflected in the November 2013 econometric cost benchmarking model) and using that benchmark to evaluate performance going forward over a defined period of time under an incentive regulation plan.

PEG agrees that this is a "positive feature of the (benchmarking) approach" because it allows distributors to be judged against a fixed benchmark during an incentive plan, rather than against a benchmark that is updated *during* the plan. Fixed benchmarks generally create stronger incentives. Distributors' performance incentives would be weaker if the benchmarks were updated based on performance gains during the plan, and this would be the result if the econometric benchmarking model were to be re-estimated every year and used to set stretch factors while the plan was in effect.

Appendix

For each distributor, benchmarking performance is an average of the difference between that distributor's actual and predicted costs over the three most recent sample years. Algebraically, this is equal to:

$$\begin{aligned}\text{Benchmarking Performance} = {} & 1/3 \times (\text{Actual Cost} - \text{Predicted Cost})_{2010} + \\ & 1/3 \times (\text{Actual Cost} - \text{Predicted Cost})_{2011} + \\ & 1/3 \times (\text{Actual Cost} - \text{Predicted Cost})_{2012}\end{aligned}$$

Only 2012 actual cost has changed as a result of the data correction. Because predicted cost is unchanged in 2010, 2011 or 2012, and the distributor's actual cost in 2010 and 2011 is unchanged by the 2012 smart meter data correction, the formula above shows that the impact of the corrected data on any distributor's benchmarking performance measure is equal to (1/3 * the change in the distributor's actual 2012 cost) resulting from the smart meter data correction.

The table below presents the new benchmarking performance measures as a result of the corrected 2012 smart meter data. The lines in the table show the boundaries established by the Board that lead to differences in stretch factor assignments. No distributor's stretch factor assignment is impacted by this change.

	Original Prediction			Revision in Actual Cost	Revised Performance
Company	**Actual**	**Predicted**	**Difference**		
HYDRO HAWKESBURY INC.	9.542	10.118	-57.5%	-1.5%	-59.0%
WASAGA DISTRIBUTION INC.	10.586	11.01	-42.4%	-1.2%	-43.6%
NORTHERN ONTARIO WIRES INC.	10.33	10.663	-33.3%	0.0%	-33.3%
HEARST POWER DISTRIBUTION COMPANY LIMITED	9.247	9.53	-28.3%	0.0%	-28.3%
E.L.K. ENERGY INC.	10.458	10.724	-26.6%	0.0%	-26.6%
HALTON HILLS HYDRO INC.	11.585	11.841	-25.6%	-0.9%	-26.5%
HALDIMAND COUNTY HYDRO INC.	11.743	11.969	-22.6%	-0.9%	-23.5%
KITCHENER	12.687	12.906	-21.9%	-0.3%	-22.2%
COOPERATIVE HYDRO EMBRUN INC.	9.007	9.216	-20.9%	0.0%	-20.9%
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORP	9.763	9.957	-19.4%	-0.6%	-20.0%
NEWMARKET	11.872	12.055	-18.3%	0.0%	-18.3%
OSHAWA PUC NETWORKS INC.	12.21	12.389	-18.0%	-0.1%	-18.1%
GRIMSBY POWER INCORPORATED	10.665	10.836	-17.1%	0.0%	-17.1%
ESSEX POWERLINES CORPORATION	11.518	11.671	-15.3%	-0.2%	-15.5%

Company	Original Prediction Actual	Predicted	Difference	Revision in Actual Cost	Revised Performance
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	11.42	11.571	-15.2%	-0.2%	-15.4%
MILTON HYDRO DISTRIBUTION INC.	11.989	12.138	-14.8%	-0.1%	-14.9%
LAKEFRONT UTILITIES INC.	12.097	12.233	-13.6%	-1.7%	-15.3%
Entegrus Powerlines	13.838	13.957	-11.9%	1.5%	-10.4%
LONDON HYDRO INC.	13.662	13.78	-11.8%	-0.9%	-12.7%
ENERSOURCE HYDRO MISSISSAUGA INC.	10.531	10.647	-11.7%	0.0%	-11.7%
HORIZON UTILITIES CORPORATION	13.3	13.412	-11.2%	0.0%	-11.2%
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	10.087	10.191	-10.4%	0.0%	-10.4%
LAKELAND POWER DISTRIBUTION LTD.	10.929	11.029	-10.0%	-0.4%	-10.4%
HYDRO 2000 INC.	8.64	8.722	-8.2%	-1.1%	-9.3%
HYDRO ONE BRAMPTON NETWORKS INC.	13.328	13.402	-7.4%	0.0%	-7.4%
KENORA HYDRO ELECTRIC CORPORATION LTD.	11.241	11.312	-7.1%	0.0%	-7.1%
BURLINGTON HYDRO INC.	10.134	10.204	-7.0%	-0.9%	-7.9%
CAMBRIDGE and NORTH DUMFRIES HYDRO INC.	12.626	12.688	-6.1%	-0.9%	-7.0%
COLLUS POWER CORPORATION	12.4	12.458	-5.8%	0.8%	-5.0%
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	10.358	10.403	-4.5%	-0.7%	-5.2%
CENTRE WELLINGTON HYDRO LTD.	11.35	11.394	-4.4%	0.0%	-4.4%
POWERSTREAM INC.	14.274	14.316	-4.2%	0.0%	-4.2%
WHITBY HYDRO ELECTRIC CORPORATION	12.156	12.189	-3.2%	0.0%	-3.2%
ORILLIA POWER DISTRIBUTION CORPORATION	11.643	11.662	-2.0%	-1.1%	-3.1%
VERIDIAN CONNECTIONS INC.	13.043	13.061	-1.8%	-0.5%	-2.3%
WESTARIO POWER INC.	11.052	11.066	-1.5%	0.0%	-1.5%
ST. THOMAS ENERGY INC.	12.023	12.024	-0.2%	-1.2%	-1.4%
ORANGEVILLE HYDRO LIMITED	10.812	10.812	-0.1%	0.0%	-0.1%
OTTAWA RIVER POWER CORPORATION	10.853	10.854	-0.1%	0.0%	-0.1%
PUC DISTRIBUTION INC.	11.219	11.21	0.9%	-1.0%	-0.1%
NORFOLK POWER DISTRIBUTION INC.	11.642	11.632	1.0%	-0.5%	0.5%
BRANTFORD POWER INC.	12.098	12.088	1.0%	1.0%	2.0%
BLUEWATER POWER DISTRIBUTION CORPORATION	12.055	12.041	1.3%	0.3%	1.6%
KINGSTON HYDRO CORPORATION	11.726	11.71	1.6%	0.0%	1.6%
HYDRO OTTAWA LIMITED	14.063	14.046	1.7%	0.0%	1.7%
SIOUX LOOKOUT HYDRO INC.	9.864	9.837	2.7%	-0.6%	2.1%
WATERLOO NORTH HYDRO INC.	12.57	12.536	3.4%	-0.9%	2.5%
PARRY SOUND POWER CORPORATION	9.925	9.887	3.9%	0.0%	3.9%
NORTH BAY HYDRO DISTRIBUTION LIMITED	11.824	11.774	5.0%	0.0%	5.0%
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	12.67	12.611	5.9%	-1.0%	4.9%
NIAGARA-ON-THE-LAKE HYDRO INC.	12.471	12.405	6.6%	-1.0%	5.6%
NIAGARA PENINSULA ENERGY INC.	10.888	10.819	6.9%	0.0%	6.9%
GUELPH HYDRO ELECTRIC SYSTEMS INC.	12.38	12.287	9.4%	-1.1%	8.3%
GREATER SUDBURY HYDRO INC.	12.555	12.46	9.5%	0.0%	9.5%
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	11.477	11.367	11.0%	-0.8%	10.2%

Company	Original Prediction Actual	Predicted	Difference	Revision in Actual Cost	Revised Performance
ERIE THAMES POWERLINES CORPORATION	12.749	12.638	11.1%	0.0%	11.1%
TILLSONBURG HYDRO INC.	10.539	10.417	12.2%	0.0%	12.2%
FORT FRANCES POWER CORPORATION	9.995	9.865	13.0%	-0.7%	12.3%
WELLINGTON NORTH POWER INC.	10.072	9.942	13.0%	-0.3%	12.7%
CANADIAN NIAGARA POWER INC.	12.113	11.972	14.1%	-0.1%	14.0%
PETERBOROUGH DISTRIBUTION INCORPORATED	12.125	11.971	15.4%	-1.1%	14.3%
BRANT COUNTY POWER INC.	10.087	9.916	17.1%	-0.6%	16.5%
RENFREW HYDRO INC.	11.14	10.967	17.3%	0.0%	17.3%
ATIKOKAN HYDRO INC.	9.551	9.366	18.5%	0.0%	18.5%
MIDLAND POWER UTILITY CORPORATION	12.996	12.81	18.6%	-0.9%	17.7%
ENWIN UTILITIES LTD.	10.672	10.477	19.5%	0.0%	19.5%
CHAPLEAU PUBLIC UTILITIES CORPORATION	11.6	11.396	20.4%	-1.6%	18.8%
FESTIVAL HYDRO INC.	8.894	8.689	20.6%	-1.0%	19.6%
WEST COAST HURON ENERGY INC.	9.9	9.682	21.8%	-0.1%	21.7%
WOODSTOCK HYDRO SERVICES INC.	11.471	11.153	31.8%	0.0%	31.8%
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	15.414	14.967	44.8%	0.0%	44.8%
HYDRO ONE NETWORKS INC.	16.152	15.569	58.3%	-0.1%	58.2%
ALGOMA POWER INC.	12.201	11.546	65.5%	0.0%	65.5%