Empirical Research in Support of Incentive Rate-Setting: 2018 Benchmarking Update

Report to the Ontario Energy Board

August 2019

PEG

Pacific Economics Group Research, LLC

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TABLE OF CONTENTS

1. Introduction

In 2013, as part of the IRM-4 proceeding EB-2010-0379, the Ontario Energy Board (OEB) issued a report titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors"[1] (Board Report) in which it set forth the framework for setting rate adjustment formulas for local distribution companies (LDCs or "distributors"). The Board Report provides the OEB's final determination on its policies and approaches to the distributor rate adjustment parameters and the benchmarking of electricity distributor total cost performance for the 2014 to 2018 rate-year period. The OEB has recently decided to extend this benchmarking. This 2018 Benchmarking Update for distributors determines their 2019 stretch factor assignments in relation to the 2020 rate year.

According to the Board Report, rates will be indexed by a formula "which is used to adjust the distribution rates to reflect expected growth in the distributors' input prices (the inflation factor) less allowance for appropriate rates of productivity and efficiency gains (the X-factor)."[2] The productivity part of the X-Factor is the same for all LDCs. The efficiency gains part of the X-Factor is called the stretch factor and can vary by company. This stretch factor reflects the potential for incremental productivity gains by a given LDC under incentive regulation (i.e., incentive rate mechanism or IRM) which in turn depends on an individual distributor's level of cost efficiency.

These stretch factor assignments are based on the results of a statistical cost benchmarking study designed to make inferences on individual distributors' cost efficiency. An econometric model is used to predict the level of cost associated with each distributor's operating conditions. Distributors that had actual cost that was lower than that predicted by the model were assigned lower stretch factors than those that did not. The October 18, 2013 report by Pacific Economics Group (PEG) titled "Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario" describes the model used to produce the benchmarking results. The work was subsequently updated to include 2013 data in July of 2014[3] and has been updated

[1] Issued on November 21, 2013 and corrected on December 4, 2013.

[2] Board Report, page 5.

[3] "Empirical work in Support of Incentive Rate Setting: 2013 Benchmarking Update".

each year since. This report presents updated benchmarking results that incorporates 2018 data to update the stretch factors.

Section 2 of this report discusses the methodology used for the 2018 update. Section 3 discusses the data used. Section 4 presents the benchmarking results and updated stretch factors. Section 5 discusses additional resources available to distributors to validate the results contained in this report.

2. Benchmarking Methodology

The model used to determine the cost efficiency of distributors is based on econometrics. Distributor cost in this model is estimated as a function of business conditions faced by each distributor. These business conditions include the number of customers served and the price of inputs such as labor and capital. The parameters of this model establish the relationship between each business condition and distributor cost. These parameters were estimated using Ontario LDC data from 2002-2012.

The model can make a prediction of each distributor's cost given its business conditions by multiplying the company's business condition variables by the model parameters and summing the results[4]. The distributor's actual cost is then compared to that predicted by the model. The percentage difference between actual and predicted cost is the measure of cost performance. Companies with larger negative differences between actual and predicted costs are considered to be better cost performers and therefore eligible for lower stretch factors. A

[4] The table of parameters published in the PEG report was for the full sample. When making predictions of cost for each company, the econometric program estimated the model without including the subject of benchmarking in the sample. Therefore, there exist 63 different sets of parameters which are very similar to each other. For ease of presentation, the PEG report did not present the parameters specific to each distributor. These company-specific parameters are necessary for the 2013 calculations and are contained within the working papers associated with this report.

detailed description of the econometric model including estimation technique and other technical details are contained in sections 6 and A2.1 of the PEG report.

The econometric model used to obtain the updated stretch factors is identical to the model described in the PEG report. The OEB intentionally decided not to update the parameters of the econometric model to include future data. The goal was to establish a fixed benchmark that would allow companies a fair opportunity to demonstrate continuous improvement of cost performance and earn a lower stretch factor. The parameters from the previous model were combined with each company's data – including 2013-2018 data - to produce 2018 predicted cost. The rationale for this decision is discussed in the Board Report and in a memorandum by PEG that also makes some corrections to the 2012 results.[5] The PEG memorandum contains the corrected final results of the 2010-2012 benchmarking model used in this update.

To apply the 2018 values to the model parameters, the data must be transformed to be consistent with how the data were specified for the estimated econometric model. One example of a transformation is that many of the explanatory variables were expressed as logarithms prior to the model being estimated. The PEG report describes the details of the estimation process in section A2.1. The spreadsheet model and associated documentation discussed in section 5 contain the calculations leading to the cost benchmarking results.

The purpose of the benchmarking work is to evaluate the total cost incurred by each distributor. Table 1 shows the formulas used to calculate the measure of total cost used in PEG's benchmarking analysis. As described in the PEG benchmarking report, adjustments were undertaken with the purpose of standardizing cost in order to facilitate more accurate cost comparisons among distributors. These adjustments included the treatment of high voltage and low voltage costs.

The variables used to explain total cost are the same as in the previous PEG report. They include outputs such as customers, kWh deliveries, and capacity. Prices for capital and OM&A along with other business conditions such as customer growth and average length of lines are also included. A complete discussion of the explanatory variables can be found in section 6 of the PEG report and the documents discussed in section 5. The explanatory variables are used to

[5] Available on the OEB website in the file "PEG_Memorandum_OEB on_corrections_20131220.pdf"

explain the level of cost incurred by each LDC. Cost that is not explained by the variables is deemed to be due to management performance.

3. Benchmarking Data

The source of the cost and output data used in the calculations is from the distributors as reported in the reporting and record-keeping requirements (RRR) filings. The study assumes that the data as reported by the distributors conforms to accounting policies and procedures described in the Accounting Procedures Handbook for Electricity Distributors that includes the Uniform System of Accounts and other instructions contained within the RRR filing system. It is also assumed that the LDCs have taken ownership of the data provided to the OEB and significant revisions are not anticipated.[6] On March 31, 2015, the OEB established new requirement for certification of the electricity distributors' RRRs. To underscore the importance that the OEB places on the accuracy and integrity of distributor reporting, particularly in the context of the new performance based regulatory framework, the OEB required that any RRR filing with the OEB be certified by an executive signing officer of the company (e.g., Chief Executive Officer, Chief Financial Officer). The new executive certification was required for both quarterly and annual RRR filings.

Data sources apart from the RRR are related to input prices. OEB-approved rates of return were obtained from OEB Staff. The source for other input price data was Statistics Canada. The input price indexes used were the same as those used in PEG's original study with one exception. Statistics Canada no longer calculates the Electric Utility Construction Price Index (EUCPI). The growth in the GDPIPI (FDD) was used to escalate the EUCPI values used the calculations.[7]

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[6] The Ontario Energy Board (OEB) released the Report of the Board on Scorecard (EB-2010-0379) on March 5, 2014 (the "Scorecard Report") states that: '*While the Board will create consistent Scorecard reports for distributors, ownership of the data and Scorecard resides with the distributor.'*

[7] GDPIPI (FDD) is the Gross Domestic Product Implicit Price Index for Final Domestic Demand.

The update was done in the same manner as the original work with a few exceptions. The first is that the OEB has improved the quality of the guidance given to distributors related to capital additions data. As a result, improved data are available for 2013-2018. PEG has accordingly relied upon these newly-available capital additions data instead of inferring these data from changes in gross plant[8]. The second exception is related to the treatment of deferred smart meter OM&A expenses. In the original PEG report, an adjustment was made for the estimated amount of amortization that was included in the reported OM&A expenses as a result of clearing amounts from account 1556. In 2014, OEB staff had advised that due to improved reporting requirements, this adjustment is no longer necessary. A survey of LDC disposition of account 1556 amounts has confirmed this.

The calculations have also been adjusted for amalgamations that have taken place since the original study was done. The historical cost performance of the combined entity was calculated from the historical results of the predecessor distributors that were amalgamated or acquired. The most recent amalgamations are the integration of St. Thomas into Entegrus and the integration of Midland into Newmarket-Tay. Previous amalgamations included the acquisition of Haldimand, Woodstock, and Norfolk by Hydro One Networks, the formation of Energy +, the Lakeland acquisition of Parry Sound and the creation of Alectra from Enersource, Horizon, PowerStream, and Hydro One Brampton Networks.[9]

This report also addresses the impact of data revisions by LDCs. The OEB requires distributors to be accountable for the integrity of their reported data. As part of its procedures to improve data quality, the OEB invited distributors to submit corrections to previously provided

[8] This improvement in data quality also extends to the collection of smart meter capital additions. The previous study estimated capital additions for distribution capital exclusive of meters for the period 2006-2012 in order to be able to isolate the accounting treatment of smart meters. The capital expenditures on smart meters were gathered for each company via a supplemental data request. These capital expenditures were then used as a proxy for capital additions and added to the total. A survey of the composition of the reported gross capital additions has revealed that some distributors have included amounts cleared from account 1555. The capital additions data for these companies has been adjusted to remove the cleared smart meter capital additions to avoid double counting.

[9] The method used to calculation the hypothetical historical cost performance of the combined entity is to sum the actual costs, sum the costs predicted by the model, and calculate the percentage difference. This method is essentially a cost-weighted average of the historical cost performances of the amalgamated distributors.

data. However, a key determination is that already established and published benchmarking results for prior years would not be modified as a result of the new data. This includes any year that comprised the three-year average used to determine the current year's stretch factor. As stretch factors are used directly to set the distribution rates of distributors, they are not subsequently adjusted to avoid retroactive rate setting (i.e., rates are final once set unless approved on an interim basis). Consequently, the three years of data used to derive the three-year average for any year's stretch factors are locked-in such that the underlying data used do not change due to any subsequent data revisions. [10]

However, to show the impacts of data changes on the stretch factors, revised data have been incorporated into the benchmarking databases and model to allow previous results to be recalculated. The revised 2017 and 2016 results are presented only for the purposes of showing the impact of the data changes but were not used as discussed above to calculate the new 2016-2018 average cost performance used to determine the 2019 stretch factors assignments.

Several tables are included at the end of this report. Table 1 describes the calculation of total cost. Table 2 shows each distributor's growth in total cost from 2017 to 2018. Table 3 (A) presents the 2018 benchmarking results and a comparison to prior years' results. Table 3 (B) summarizes data revision impacts on cost performance although they have no bearing on the derivation of the current stretch factors. Table 4 presents average cost performance and associated stretch factors. Table 5 presents the companies assigned to each cohort according to their updated stretch factors. Changes from the previous year's assignments are shown in bold.

The goal of the benchmarking work is to evaluate levels of distributor cost. Table 2 presents the actual OM&A, Capital, and Total cost for each distributor for 2017 and 2018. As can be seen, industry total cost increased by 4.68% on average from 2017-2018. Whereas OM&A cost grew on average by 2.34%, capital cost increased on average by 7.18%. The

[10] The previous results were "locked-in" by pasting the values of previous cost performance into the 2018 part of the calculations. This means that these values are will not be affected by subsequent data revisions. This allows for the calculation of a new three-year average of the new 2018 result consistent with the previously published 2016-2017 results while still allowing the calculation of revised results for previous years, if applicable, to show the impact of any data revision.

increase in capital cost (2018 vs. 2017) is principally due to higher capital investments in the distribution system, and slight increases in the rates of return and inflation.

The econometric model estimates LDCs' costs as a function of distributor output, input price growth, and other business condition variables beyond management control. It will also produce a prediction of the level of cost consistent with these business conditions and thus "explain" some of the observed cost level. As described in the PEG benchmarking report, changes not accounted for by these factors are deemed to be due to management performance. The parameter estimates measure the cost impact of the different business conditions and are presented on Table 16 of the PEG benchmarking report. The discussion below provides some details about the parameters and their associated impacts established for the 2002 to 2012 period.

The first of the cost drivers is output quantity. The model uses three measures for the quantity of distributor output. The first is the number of customers served and the second is kWh delivered. The third is a proxy for the capacity of the distribution system. The capacity variable is described in the PEG report and is equal to the largest peak load experienced as of the current year of data. For example, the 2012 value for the capacity variable is equal to largest reported system summer or winter kW in all the years 2002-2012. Therefore, for 2013, this capacity variable only increased if the distributor's kW demand in that year exceeded kW demand in every year between 2002 and 2012. Of the three output variables, the model estimates that the number of customers has the largest impact on cost, followed by the system capacity variable. The kWh delivered was the least important of the output variables. For the average company, the number of customers was found to be a more important cost driver than the other two combined. For each 1% change in number of customers, cost was estimated to change by 0.44%.

The second group of cost drivers were the input prices for capital and OM&A. For the average company, the cost impact of changes in the capital price was found to be almost twice as important as that for OM&A. For every 1% change in capital price, the impact on total cost was about 0.63%. The corresponding impact for changes in the OM&A price was 0.37%. The relevant indexes were updated to include 2018 data. For the OM&A price, the growth in average weekly earnings and that for the GDP implicit price index for final domestic demand ("GDPIPI (FDD)") were calculated. The 2018 growth in the OM&A price index is calculated as 70% times average weekly earnings growth plus 30% times GDPIPI (FDD) growth. The 2017 values for the OM&A price index from the previous report were escalated by the growth that occurred in 2018.

The capital price calculation is based upon an asset price index, an economic depreciation rate, and a rate of return. The asset price index was the Electric Utility Construction Price Index as calculated by Statistics Canada. As this index is no longer available, the previous values are escalated by an alternate index. The index chosen was the GDPIPI (FDD) which is the same index used to represent all non-labour price inflation in the Board-approved inflation measure formula[11]. The depreciation rate is fixed at 4.59% consistent with the previous work. The rate of return is a weighted average of the rates for return on equity, long-term debt, and short-term debt as approved by the OEB. The capital price used to calculate total cost is also used as an explanatory variable. Therefore, any changes in the rate of return that affect the cost calculation will also affect the price calculation which will in turn "explain" the observed changes in cost.

The last group of cost drivers consists of other business condition variables. The first was the percentage of customers added over the last ten years. The second was the average km of distribution line. For each 1% change in line length, total cost was estimated to increase by 0.29%. The model also contains a time trend that accounts for changes in cost over time that are not accounted for by the other cost drivers. This variable estimates that cost should rise by 1.7% per year for reasons not identified by other variables in the model. All of these business condition variables were updated to include 2018 data.

4. Benchmarking Results and Updated Stretch Factors

Table 3 (A) presents a summary of the current benchmarking results for each distributor from 2016-2018. The updated average cost performance is based on a three-year rolling average calculated from the 2016-2018 values and is used to assign updated stretch factors to distributors. The last column presents the difference between the updated average cost performance and the previous one (2015-2017). All except for one distributor had average cost performances that

[11] The weight given to the non-labour index in the inflation formula includes capital cost.

changed by less than 5%[12] from the previous update. The average level of cost performance in 2018 for the 63 distributors is 5.8% lower than forecast cost that builds upon cost performance improvement in previous years. Previous years have shown lower levels of performance improvements for these distributors (i.e., lower than forecast cost of 4.4% in 2017, 3.0% in 2016 and 2.6% in 2015).

As discussed above, the OEB requires distributors to be accountable for the integrity of their reported data and sets out reporting procedures to improve data quality. OEB Staff reviewed and approved distributors' data corrections requests to previously filed data when reasonable justification is provided. PEG evaluated the data provided in response to the data request to identify any warranted corrections. The revised data were incorporated into separate benchmarking databases and the 2016 and 2017 results were recalculated to demonstrate the impact on the previously published 2015-2017 average cost performance. Table 3 (B) shows the impact of LDC data revisions on 2016 and 2017 cost performance for those companies that had approved changes since the previous update[13]. No revisions would have changed previously determined cohort placement.

Updated stretch factors are assigned based on a three-year average of actual less predicted cost over the 2016-2018 period. As discussed in the Board Report, distributors that averaged 25% or more below cost received the lowest stretch factor of 0%. Those that averaged in excess of 10% and up to 25% below cost received a stretch factor of 0.15%. Those within 10% of predicted cost received a stretch factor of 0.30%. Those distributors that had cost in excess of 10% and up to 25% of that predicted received a stretch factor of 0.45%. Any distributors that had cost in excess of 25% more than predicted were assigned the highest stretch factor of 0.60%.

Table 4 presents a summary of the current and previous years' cost performance results and corresponding stretch factors. The assigned stretch factor for most companies was not affected by the 2018 update. A total of five companies have been assigned different stretch

[12] Changes in average cost performance are due to not only the addition of 2018 results, but the removal of 2015 results. It is therefore possible to simultaneously have improved 2018 cost performance and deteriorating average performance.

[13] There were no accepted revisions to 2015 data since the previous update.

factors and all five now have lower stretch factors. Table 5 presents the updated stretch factor assignments in the format of Appendix D of the Board report.

5. Validation and Other Supporting Documents

As part of their reporting requirements, distributors are asked to validate the numbers contained in their scorecard. The Spreadsheet Model as updated produces the updated benchmarking results contained in this report. It builds on the previous version by adding additional worksheets related to the 2018 calculations. It also now contains additional improvements to help ensure that the results as calculated are accurately translated into the distributor scorecards and the tables in this report.

The format of the additional worksheets used in the update are similar to those provided earlier and the User's Guide will be applicable to the new worksheets. The guide is intended to serve as a tool for distributors to better understand these calculations and their cost performance. The spreadsheet model and users guide are available in the Total cost benchmarking – updates section of the Performance assessment page on the OEB's website.

Table 1

Calculation of 2018 Total Cost

Variable		Reference	Formula	Source
Total Cost			= OM&A + Capital Cost	Formula
OM&A			= A+B+C+D+E+F+G-I+J	Formula
2018	Operation	A		RRR
2018	Maintenance	B		RRR
2018	Billing and Collection	C		RRR
2018	Community Relations	D		RRR
2018	Administrative and General Expenses	E		RRR
2018	Insurance Expense	F		RRR
2018	Advertising Expenses	G		RRR
Adjustments to OM&A				
2018	HV Adjustment	I		RRR
2018	LV Adjustment	J		Hydro One Networks
Capital				
2017	Asset Price Index	K		Previous Year Calculations
2017	Capital Price	L		Previous Year Calculations
2017	Capital Quantity	M		Previous Year Calculations
2017	Capital cost	N		Previous Year Calculations
2018	Asset Price Index	O	=K x (GDPPI-FDD 2016 / GDPPI-FDD 2015)	Formula, Statistics Canada
2018	Capital Additions	P		RRR
2018	HV Capital Additions	Q		RRR
2018	Quantity of Capital Additions	R	=(P-Q) / O	Formula
	Depreciation Rate	S	Fixed at 4.59% for All Years	PEG Report
2018	Capital Quantity	T	= M - S x M + R	Formula
2018	Rate of Return	U		OEB Staff
2018	Capital Price	V	=U x K + S x O	Formula
2018	Capital Cost	W	= V x T	Formula

Table 2

Total Cost by Distributor: 2017 vs. 2018

	OM&A Cost			Capital Cost			Total Cost		
	2017	2018	Percent Change	2017	2018	Percent Change	2017	2018	Percent Change
Alectra Utilities Corporation	253,135,398	226,830,298	-10.97%	413,751,228	448,659,064	8.10%	666,886,626	675,489,361	1.28%
Algoma Power Inc.	11,949,456	11,930,620	-0.16%	12,855,216	13,643,491	5.95%	24,804,672	25,574,112	3.05%
Atikokan Hydro Inc.	1,128,041	1,087,097	-3.70%	512,241	588,363	13.85%	1,640,282	1,675,460	2.12%
Bluewater Power Distribution Corporation	13,327,256	13,754,074	3.15%	12,023,225	13,013,655	7.92%	25,350,482	26,767,729	5.44%
Brantford Power Inc.	9,372,903	9,964,565	6.12%	10,587,269	11,058,211	4.35%	19,960,172	21,022,776	5.19%
Burlington Hydro Inc.	17,672,918	18,025,935	1.98%	23,140,723	24,594,385	6.09%	40,813,641	42,620,320	4.33%
Canadian Niagara Power Inc.	8,980,025	10,228,808	13.02%	13,485,909	15,124,610	11.47%	22,465,934	25,353,418	12.09%
Centre Wellington Hydro Ltd.	2,366,911	2,464,520	4.04%	2,365,159	2,521,655	6.41%	4,732,071	4,986,175	5.23%
Chapleau Public Utilities Corporation	714,794	744,872	4.12%	176,373	230,567	26.79%	891,168	975,438	9.04%
EPCOR Electricity Distribution Ontario Inc.	4,564,267	4,816,102	5.37%	4,219,678	4,507,376	6.60%	8,783,946	9,323,478	5.96%
Cooperative Hydro Embrun Inc.	666,866	689,126	3.28%	486,157	510,711	4.93%	1,153,022	1,199,837	3.98%
E.L.K. Energy Inc.	2,601,207	2,605,463	0.16%	2,263,676	2,383,382	5.15%	4,864,883	4,988,845	2.52%
Energy+ Inc.	17,339,704	17,677,971	1.93%	24,109,579	25,642,530	6.16%	41,449,284	43,320,501	4.42%
Entegrus Powerlines Inc.	13,088,795	13,576,025	3.65%	18,412,101	19,719,965	6.86%	31,500,896	33,295,990	5.54%
EnWin Utilities Ltd.	26,481,205	25,555,586	-3.56%	36,070,868	38,208,169	5.76%	62,552,073	63,763,755	1.92%
ERTH Power Corporation	6,303,144	6,208,209	-1.52%	6,367,344	6,845,695	7.24%	12,670,489	13,053,904	2.98%
Espanola Regional Hydro Distribution Corporation	1,452,179	1,482,629	2.08%	722,220	773,750	6.89%	2,174,399	2,256,379	3.70%
Essex Powerlines Corporation	6,904,038	7,545,389	8.88%	9,116,771	9,802,132	7.25%	16,020,809	17,347,521	7.96%
Festival Hydro Inc.	5,423,944	6,168,269	12.86%	7,493,569	7,900,687	5.29%	12,917,513	14,068,956	8.54%
Fort Frances Power Corporation	1,624,397	1,619,179	-0.32%	869,845	910,944	4.62%	2,494,242	2,530,123	1.43%
Greater Sudbury Hydro Inc.	13,736,803	14,687,809	6.69%	16,117,811	17,287,490	7.01%	29,854,613	31,975,298	6.86%
Grimsby Power Incorporated	2,934,569	3,128,103	6.39%	3,417,624	3,619,182	5.73%	6,352,193	6,747,285	6.03%
Guelph Hydro Electric Systems Inc.	14,940,539	16,367,154	9.12%	19,535,225	20,856,276	6.54%	34,475,764	37,223,430	7.67%
Halton Hills Hydro Inc.	5,991,470	6,069,683	1.30%	10,943,264	11,751,841	7.13%	16,934,734	17,821,525	5.10%
Hearst Power Distribution Company Limited	1,097,095	1,135,359	3.43%	330,502	360,263	8.62%	1,427,597	1,495,622	4.65%
Hydro 2000 Inc.	573,244	546,524	-4.77%	135,318	140,259	3.59%	708,562	686,783	-3.12%
Hydro Hawkesbury Inc.	1,067,938	1,120,620	4.82%	592,597	614,206	3.58%	1,660,535	1,734,826	4.38%
Hydro One Networks Inc.	531,008,997	535,524,472	0.85%	754,901,696	827,969,995	9.24%	1,285,910,694	1,363,494,467	5.86%
Hydro Ottawa Limited	76,585,427	81,806,255	6.59%	140,187,647	153,288,862	8.93%	216,773,074	235,095,117	8.11%
Innpower Corporation	5,967,674	5,758,129	-3.57%	8,803,370	9,387,602	6.43%	14,771,044	15,145,732	2.51%
Kenora Hydro Electric Corporation Ltd.	2,196,843	2,283,520	3.87%	1,170,957	1,238,921	5.64%	3,367,800	3,522,441	4.49%
Kingston Hydro Corporation	6,668,210	7,381,155	10.16%	8,161,402	8,730,212	6.74%	14,829,612	16,111,367	8.29%
Kitchener-Wilmot Hydro Inc.	16,163,456	17,517,341	8.04%	30,492,178	32,715,645	7.04%	46,655,634	50,232,987	7.39%
Lakefront Utilities Inc.	2,292,335	2,607,882	12.90%	2,423,399	2,590,014	6.65%	4,715,734	5,197,896	9.73%
Lakeland Power Distribution Ltd.	4,833,159	5,311,137	9.43%	4,572,445	4,836,119	5.61%	9,405,604	10,147,256	7.59%
London Hydro Inc.	35,729,769	37,400,594	4.57%	45,328,100	50,450,167	10.71%	81,057,869	87,850,760	8.05%
Milton Hydro Distribution Inc.	8,862,186	9,389,991	5.79%	16,431,885	17,637,631	7.08%	25,294,071	27,027,622	6.63%
Newmarket-Tay Power Distribution Ltd.	11,749,662	11,281,977	-4.06%	15,346,222	17,318,142	12.09%	27,095,884	28,600,118	5.40%
Niagara Peninsula Energy Inc.	17,622,603	17,326,922	-1.69%	23,049,793	24,661,333	6.76%	40,672,397	41,988,255	3.18%
Niagara-on-the-Lake Hydro Inc.	2,530,464	2,850,813	11.92%	4,011,279	4,349,050	8.08%	6,541,743	7,199,863	9.59%
North Bay Hydro Distribution Limited	6,227,380	6,070,898	-2.54%	9,978,640	10,723,875	7.20%	16,206,020	16,794,774	3.57%
Northern Ontario Wires Inc.	2,621,077	2,651,283	1.15%	1,359,176	1,450,162	6.48%	3,980,253	4,101,445	3.00%
Oakville Hydro Electricity Distribution Inc.	17,537,919	17,915,297	2.13%	31,467,323	33,898,412	7.44%	49,005,241	51,813,709	5.57%
Orangeville Hydro Limited	3,299,288	3,204,308	-2.92%	3,536,858	3,729,338	5.30%	6,836,145	6,933,646	1.42%
Orillia Power Distribution Corporation	4,709,486	4,916,240	4.30%	4,230,385	4,474,802	5.62%	8,939,871	9,391,042	4.92%
Oshawa PUC Networks Inc.	12,150,794	13,100,434	7.53%	18,503,607	20,306,089	9.30%	30,654,401	33,406,523	8.60%

Table 2

Total Cost by Distributor: 2017 vs. 2018

	OM&A Cost			Capital Cost			Total Cost		
	2017	2018	Percent Change	2017	2018	Percent Change	2017	2018	Percent Change
Ottawa River Power Corporation	3,169,087	2,855,216	-10.43%	2,401,457	2,585,948	7.40%	5,570,543	5,441,164	-2.35%
Peterborough Distribution Incorporated	8,616,790	8,748,446	1.52%	12,686,396	13,244,855	4.31%	21,303,186	21,993,301	3.19%
PUC Distribution Inc.	10,685,848	10,701,655	0.15%	11,914,328	12,488,359	4.71%	22,600,176	23,190,013	2.58%
Renfrew Hydro Inc.	1,406,742	1,440,446	2.37%	1,120,979	1,226,241	8.98%	2,527,720	2,666,687	5.35%
Rideau St. Lawrence Distribution Inc.	2,228,632	2,184,478	-2.00%	1,127,904	1,181,665	4.66%	3,356,536	3,366,143	0.29%
Sioux Lookout Hydro Inc.	1,559,987	1,454,263	-7.02%	849,706	919,053	7.85%	2,409,693	2,373,316	-1.52%
Thunder Bay Hydro Electricity Distribution Inc.	15,384,698	15,468,788	0.55%	18,016,664	19,300,969	6.89%	33,401,362	34,769,757	4.02%
Tillsonburg Hydro Inc.	2,631,316	2,854,683	8.15%	2,077,102	2,261,637	8.51%	4,708,418	5,116,320	8.31%
Toronto Hydro-Electric System Limited	234,078,557	249,021,330	6.19%	566,261,796	618,658,249	8.85%	800,340,353	867,679,579	8.08%
Veridian Connections Inc.	26,716,784	27,491,014	2.86%	42,850,724	46,010,896	7.12%	69,567,507	73,501,910	5.50%
Wasaga Distribution Inc.	3,094,041	3,166,523	2.32%	2,679,981	2,833,751	5.58%	5,774,022	6,000,274	3.84%
Waterloo North Hydro Inc.	12,895,779	13,837,414	7.05%	31,217,503	33,242,872	6.29%	44,113,282	47,080,286	6.51%
Welland Hydro-Electric System Corp.	6,597,232	6,608,044	0.16%	4,868,689	5,106,103	4.76%	11,465,921	11,714,147	2.14%
Wellington North Power Inc.	1,707,931	1,702,863	-0.30%	1,353,574	1,408,362	3.97%	3,061,505	3,111,224	1.61%
West Coast Huron Energy Inc.	1,630,646	1,687,483	3.43%	1,422,628	1,506,287	5.71%	3,053,274	3,193,770	4.50%
Westario Power Inc.	6,113,555	5,431,298	-11.83%	7,491,332	8,111,767	7.96%	13,604,887	13,543,065	-0.46%
Whitby Hydro Electric Corporation	11,961,256	11,093,577	-7.53%	17,008,651	18,127,129	6.37%	28,969,907	29,220,706	0.86%
Average			2.34%			7.18%			4.68%
Median			2.37%			6.74%			4.65%

The 2017 values for Entegrus and Newmarket-Tay have been recalculated to include St. Thomas and Midland respectively.

Table 3 (A)

Summary of Cost Performance Results

	Cost Efficiency Assessment						
	2015	2016	2017	2018	2015-2017	2016-2018	Difference from 2015-2017
Alectra Utilities Corporation	0.2%	0.2%	4.5%	-0.7%	1.6%	1.3%	-0.3%
Algoma Power Inc.	70.6%	69.8%	68.9%	66.1%	69.8%	68.2%	-1.5%
Atikokan Hydro Inc.	9.7%	11.9%	12.6%	9.6%	11.4%	11.3%	-0.1%
Bluewater Power Distribution Corporation	0.8%	2.1%	4.0%	3.7%	2.3%	3.2%	1.0%
Brantford Power Inc.	-6.1%	-4.4%	-8.2%	-9.4%	-6.2%	-7.3%	-1.1%
Burlington Hydro Inc.	-10.3%	-11.1%	-11.9%	-13.9%	-11.1%	-12.3%	-1.2%
Canadian Niagara Power Inc.	13.0%	13.5%	11.2%	17.1%	12.6%	13.9%	1.4%
Centre Wellington Hydro Ltd.	-1.2%	0.4%	1.0%	-0.3%	0.1%	0.4%	0.3%
Chapleau Public Utilities Corporation	23.9%	21.0%	17.0%	24.2%	20.6%	20.7%	0.1%
EPCOR Electricity Distribution Ontario Inc.	-14.2%	-13.2%	-18.4%	-19.3%	-15.3%	-17.0%	-1.7%
Cooperative Hydro Embrun Inc.	-33.2%	-38.2%	-41.1%	-44.8%	-37.5%	-41.4%	-3.9%
E.L.K. Energy Inc.	-34.7%	-39.4%	-44.5%	-47.8%	-39.5%	-43.9%	-4.4%
Energy+ Inc.	-5.3%	-9.9%	-11.1%	-13.1%	-8.8%	-11.4%	-2.6%
Entegrus Powerlines Inc.	-15.4%	-13.5%	-16.8%	-16.0%	-15.2%	-15.4%	-0.2%
EnWin Utilities Ltd.	9.9%	9.6%	5.3%	-2.7%	8.3%	4.1%	-4.2%
ERTH Power Corporation	7.0%	6.8%	7.8%	2.3%	7.2%	5.6%	-1.6%
Espanola Regional Hydro Distribution Corporation	-20.4%	-20.9%	-23.1%	-24.8%	-21.4%	-22.9%	-1.5%
Essex Powerlines Corporation	-13.5%	-14.3%	-14.1%	-12.3%	-14.0%	-13.6%	0.4%
Festival Hydro Inc.	14.0%	13.4%	8.8%	10.8%	12.1%	11.0%	-1.0%
Fort Frances Power Corporation	5.1%	6.8%	2.4%	-0.8%	4.8%	2.8%	-2.0%
Greater Sudbury Hydro Inc.	8.0%	9.6%	7.1%	7.6%	8.2%	8.1%	-0.1%
Grimsby Power Incorporated	-17.0%	-13.0%	-24.9%	-27.6%	-18.3%	-21.8%	-3.6%
Guelph Hydro Electric Systems Inc.	-3.8%	-5.1%	-3.5%	-2.3%	-4.1%	-3.6%	0.5%
Halton Hills Hydro Inc.	-28.2%	-27.5%	-28.4%	-29.2%	-28.0%	-28.4%	-0.3%
Hearst Power Distribution Company Limited	-7.4%	-21.3%	-20.1%	-21.3%	-16.3%	-20.9%	-4.6%
Hydro 2000 Inc.	-6.2%	-19.6%	-23.0%	-15.4%	-16.3%	-19.4%	-3.1%
Hydro Hawkesbury Inc.	-68.1%	-66.4%	-56.3%	-57.7%	-63.6%	-60.1%	3.5%
Hydro One Networks Inc.	19.7%	15.6%	17.0%	16.0%	17.4%	16.2%	-1.2%

Table 3 (A)

Summary of Cost Performance Results

	Cost Efficiency Assessment						
	2015	2016	2017	2018	2015-2017	2016-2018	Difference from 2015-2017
Hydro Ottawa Limited	15.2%	15.7%	16.5%	18.2%	15.8%	16.8%	1.0%
Innpower Corporation	8.5%	9.1%	4.7%	-2.2%	7.4%	3.8%	-3.6%
Kenora Hydro Electric Corporation Ltd.	-3.9%	-12.5%	-9.2%	-9.9%	-8.5%	-10.5%	-2.0%
Kingston Hydro Corporation	-3.1%	-2.9%	-1.4%	1.3%	-2.5%	-1.0%	1.5%
Kitchener-Wilmot Hydro Inc.	-22.3%	-20.4%	-19.9%	-19.2%	-20.9%	-19.8%	1.0%
Lakefront Utilities Inc.	-22.1%	-18.8%	-23.5%	-21.0%	-21.5%	-21.1%	0.4%
Lakeland Power Distribution Ltd.	-7.6%	-11.6%	-16.1%	-9.2%	-11.8%	-12.3%	-0.6%
London Hydro Inc.	-9.9%	-8.0%	-7.1%	-5.9%	-8.4%	-7.0%	1.3%
Milton Hydro Distribution Inc.	2.7%	-0.6%	-14.4%	-17.4%	-4.1%	-10.8%	-6.7%
Newmarket-Tay Power Distribution Ltd.	-13.7%	-11.9%	-8.6%	-10.0%	-11.4%	-10.2%	1.2%
Niagara Peninsula Energy Inc.	4.5%	3.5%	4.9%	1.3%	4.3%	3.2%	-1.1%
Niagara-on-the-Lake Hydro Inc.	-6.6%	-6.4%	-9.2%	-5.2%	-7.4%	-6.9%	0.5%
North Bay Hydro Distribution Limited	7.0%	3.2%	5.5%	3.3%	5.2%	4.0%	-1.2%
Northern Ontario Wires Inc.	-42.2%	-38.5%	-36.0%	-37.3%	-38.9%	-37.3%	1.6%
Oakville Hydro Electricity Distribution Inc.	6.9%	4.5%	2.6%	1.0%	4.7%	2.7%	-2.0%
Orangeville Hydro Limited	-7.6%	-10.2%	-14.3%	-20.0%	-10.7%	-14.8%	-4.1%
Orillia Power Distribution Corporation	-8.0%	-2.5%	-3.8%	-5.7%	-4.8%	-4.0%	0.8%
Oshawa PUC Networks Inc.	-14.9%	-15.4%	-16.3%	-14.4%	-15.6%	-15.4%	0.2%
Ottawa River Power Corporation	-9.3%	-9.8%	-10.4%	-21.9%	-9.8%	-14.0%	-4.2%
Peterborough Distribution Incorporated	11.0%	12.6%	8.2%	5.8%	10.6%	8.9%	-1.7%
PUC Distribution Inc.	16.2%	14.0%	11.2%	8.2%	13.8%	11.1%	-2.7%
Renfrew Hydro Inc.	10.6%	10.6%	7.7%	7.2%	9.6%	8.5%	-1.1%
Rideau St. Lawrence Distribution Inc.	-4.8%	-8.1%	-4.1%	-9.4%	-5.7%	-7.2%	-1.5%
Sioux Lookout Hydro Inc.	-4.3%	-3.4%	-7.9%	-16.9%	-5.2%	-9.4%	-4.2%
Thunder Bay Hydro Electricity Distribution Inc.	8.6%	12.2%	11.2%	9.3%	10.7%	10.9%	0.2%
Tillsonburg Hydro Inc.	-0.5%	1.6%	-1.2%	3.2%	0.0%	1.2%	1.2%
Toronto Hydro-Electric System Limited	51.5%	52.3%	52.9%	53.0%	52.3%	52.7%	0.5%
Veridian Connections Inc.	-2.7%	-1.6%	-3.1%	-4.6%	-2.5%	-3.1%	-0.6%
Wasaga Distribution Inc.	-45.6%	-44.9%	-45.7%	-46.7%	-45.4%	-45.8%	-0.4%

Table 3 (A)

Summary of Cost Performance Results

	Cost Efficiency Assessment						
	2015	2016	2017	2018	2015-2017	2016-2018	Difference from 2015-2017
Waterloo North Hydro Inc.	8.2%	9.9%	9.5%	9.7%	9.2%	9.7%	0.5%
Welland Hydro-Electric System Corp.	-18.7%	-17.4%	-19.6%	-24.0%	-18.5%	-20.3%	-1.8%
Wellington North Power Inc.	11.8%	16.2%	12.7%	8.7%	13.6%	12.5%	-1.0%
West Coast Huron Energy Inc.	33.5%	34.9%	26.8%	26.5%	31.7%	29.4%	-2.3%
Westario Power Inc.	-6.0%	-2.7%	-1.5%	-8.5%	-3.4%	-4.2%	-0.8%
Whitby Hydro Electric Corporation	-2.6%	-1.9%	-2.1%	-7.6%	-2.2%	-3.9%	-1.7%
Average	-2.6%	-3.0%	-4.4%	-5.8%	-3.3%	-4.4%	-1.1%
Median	-3.8%	-2.7%	-3.5%	-5.7%	-4.1%	-4.0%	-1.0%
Max	70.6%	69.8%	68.9%	66.1%	69.8%	68.2%	3.5%
Min	-68.1%	-66.4%	-56.3%	-57.7%	-63.6%	-60.1%	-6.7%

Table 3 (B)

Summary of the Impact of Revised Data on Cost Performance Results

LDCs with approved 2016 and/or 2017 data revisions	2016 Cost Performance			2017 Cost Performance			2015-2017 Average Cost Performance*		
	As Previously Calculated	As Revised	Difference	As Previously Calculated	As Revised	Difference	As Previously Calculated	As Revised	Difference
Alectra Utilities Corporation	na	na	na	4.54%	0.25%	4.29%	1.64%	0.21%	-1.43%
Hydro 2000 Inc.	-19.57%	-20.62%	1.05%	-23.05%	-7.23%	-15.82%	-16.27%	-11.34%	4.92%
EPCOR Electricity Distribution Ontario Inc.	-13.18%	-13.14%	-0.04%	-18.40%	-18.36%	-0.04%	-15.25%	-15.23%	0.03%
Hydro Hawkesbury Inc.	-66.37%	-58.01%	-8.36%	-56.30%	-49.38%	-6.92%	-63.59%	-58.50%	5.09%
Lakefront Utilities Inc.	-18.81%	-18.80%	-0.01%	-23.52%	-20.08%	-3.44%	-21.46%	-20.31%	1.15%
Greater Sudbury Hydro Inc.	9.62%	12.57%	-2.96%	7.11%	9.18%	-2.07%	8.25%	9.92%	1.68%
Chapleau Public Utilities Corporation	21.02%	21.02%	0.00%	17.02%	17.43%	-0.41%	20.64%	20.77%	0.14%
E.L.K. Energy Inc.	-39.45%	-39.45%	0.00%	-44.47%	-42.01%	-2.46%	-39.54%	-38.72%	0.82%
Hydro One Networks Inc.	15.56%	15.56%	0.00%	16.983%	16.985%	-0.002%	17.409%	17.410%	0.001%
Entegrus Powerlines Inc.	-15.71%	-15.71%	0.00%	-17.52%	-17.56%	0.04%	-15.23%	-16.22%	-0.99%
Newmarket-Tay Power Distribution Ltd.	-16.67%	-16.67%	0.00%	-12.21%	-12.49%	0.28%	-11.41%	-14.30%	-2.89%
Niagara Peninsula Energy Inc.	3.49%	3.49%	0.00%	4.86%	4.84%	0.02%	4.30%	4.29%	-0.01%
St. Thomas Energy Inc.	-7.70%	-7.70%	0.00%	-14.83%	-14.81%	-0.02%	-10.93%	-10.93%	0.01%
Tillsonburg Hydro Inc.	1.59%	1.56%	0.03%	-1.15%	-1.16%	0.01%	-0.01%	-0.03%	-0.01%
Fort Frances Power Corporation	6.84%	6.09%	0.75%	2.43%	2.41%	0.02%	4.79%	4.54%	-0.26%
Espanola Regional Hydro Distribution Corporation	-20.85%	-20.85%	0.00%	-23.08%	-22.31%	-0.77%	-21.43%	-21.17%	0.26%

* There were no new revisions to 2015 data

Table 4

Summary of Stretch Factor Assignments

	2015-2017*		2016-2018		Change in Stretch Factor
	Benchmarking Performance	Stretch Factor	Benchmarking Performance	Stretch Factor	
Alectra Utilities Corporation	1.6%	0.30	1.3%	0.30	NO
Algoma Power Inc.	69.8%	0.60	68.2%	0.60	NO
Atikokan Hydro Inc.	11.4%	0.45	11.3%	0.45	NO
Bluewater Power Distribution Corporation	2.3%	0.30	3.2%	0.30	NO
Brantford Power Inc.	-6.2%	0.30	-7.3%	0.30	NO
Burlington Hydro Inc.	-11.1%	0.15	-12.3%	0.15	NO
Canadian Niagara Power Inc.	12.6%	0.45	13.9%	0.45	NO
Centre Wellington Hydro Ltd.	0.1%	0.30	0.4%	0.30	NO
Chapleau Public Utilities Corporation	20.6%	0.45	20.7%	0.45	NO
EPCOR Electricity Distribution Ontario Inc.	-15.3%	0.15	-17.0%	0.15	NO
Cooperative Hydro Embrun Inc.	-37.5%	0.00	-41.4%	0.00	NO
E.L.K. Energy Inc.	-39.5%	0.00	-43.9%	0.00	NO
Energy+ Inc.	**-8.8%**	**0.30**	**-11.4%**	**0.15**	**YES**
Entegrus Powerlines Inc.	-15.2%	0.15	-15.4%	0.15	NO
EnWin Utilities Ltd.	8.3%	0.30	4.1%	0.30	NO
ERTH Power Corporation	7.2%	0.30	5.6%	0.30	NO
Espanola Regional Hydro Distribution Corporation	-21.4%	0.15	-22.9%	0.15	NO
Essex Powerlines Corporation	-14.0%	0.15	-13.6%	0.15	NO
Festival Hydro Inc.	12.1%	0.45	11.0%	0.45	NO
Fort Frances Power Corporation	4.8%	0.30	2.8%	0.30	NO
Greater Sudbury Hydro Inc.	8.2%	0.30	8.1%	0.30	NO
Grimsby Power Incorporated	-18.3%	0.15	-21.8%	0.15	NO
Guelph Hydro Electric Systems Inc.	-4.1%	0.30	-3.6%	0.30	NO
Halton Hills Hydro Inc.	-28.0%	0.00	-28.4%	0.00	NO
Hearst Power Distribution Company Limited	-16.3%	0.15	-20.9%	0.15	NO
Hydro 2000 Inc.	-16.3%	0.15	-19.4%	0.15	NO
Hydro Hawkesbury Inc.	-63.6%	0.00	-60.1%	0.00	NO
Hydro One Networks Inc.	17.4%	0.45	16.2%	0.45	NO
Hydro Ottawa Limited	15.8%	0.45	16.8%	0.45	NO
Innpower Corporation	7.4%	0.30	3.8%	0.30	NO
Kenora Hydro Electric Corporation Ltd.	**-8.5%**	**0.30**	**-10.5%**	**0.15**	**YES**
Kingston Hydro Corporation	-2.5%	0.30	-1.0%	0.30	NO
Kitchener-Wilmot Hydro Inc.	-20.9%	0.15	-19.8%	0.15	NO
Lakefront Utilities Inc.	-21.5%	0.15	-21.1%	0.15	NO
Lakeland Power Distribution Ltd.	-11.8%	0.15	-12.3%	0.15	NO
London Hydro Inc.	-8.4%	0.30	-7.0%	0.30	NO

Table 4

Summary of Stretch Factor Assignments

	2015-2017*		2016-2018		Change in Stretch Factor
	Benchmarking Performance	Stretch Factor	Benchmarking Performance	Stretch Factor	
Milton Hydro Distribution Inc.	**-4.1%**	**0.30**	**-10.8%**	**0.15**	**YES**
Newmarket-Tay Power Distribution Ltd.	-11.4%	0.15	-10.2%	0.15	NO
Niagara Peninsula Energy Inc.	4.3%	0.30	3.2%	0.30	NO
Niagara-on-the-Lake Hydro Inc.	-7.4%	0.30	-6.9%	0.30	NO
North Bay Hydro Distribution Limited	5.2%	0.30	4.0%	0.30	NO
Northern Ontario Wires Inc.	-38.9%	0.00	-37.3%	0.00	NO
Oakville Hydro Electricity Distribution Inc.	4.7%	0.30	2.7%	0.30	NO
Orangeville Hydro Limited	-10.7%	0.15	-14.8%	0.15	NO
Orillia Power Distribution Corporation	-4.8%	0.30	-4.0%	0.30	NO
Oshawa PUC Networks Inc.	-15.6%	0.15	-15.4%	0.15	NO
Ottawa River Power Corporation	**-9.8%**	**0.30**	**-14.0%**	**0.15**	**YES**
Peterborough Distribution Incorporated	**10.6%**	**0.45**	**8.9%**	**0.30**	**YES**
PUC Distribution Inc.	13.8%	0.45	11.1%	0.45	NO
Renfrew Hydro Inc.	9.6%	0.30	8.5%	0.30	NO
Rideau St. Lawrence Distribution Inc.	-5.7%	0.30	-7.2%	0.30	NO
Sioux Lookout Hydro Inc.	-5.2%	0.30	-9.4%	0.30	NO
Thunder Bay Hydro Electricity Distribution Inc.	10.7%	0.45	10.9%	0.45	NO
Tillsonburg Hydro Inc.	0.0%	0.30	1.2%	0.30	NO
Toronto Hydro-Electric System Limited	52.3%	0.60	52.7%	0.60	NO
Veridian Connections Inc.	-2.5%	0.30	-3.1%	0.30	NO
Wasaga Distribution Inc.	-45.4%	0.00	-45.8%	0.00	NO
Waterloo North Hydro Inc.	9.2%	0.30	9.7%	0.30	NO
Welland Hydro-Electric System Corp.	-18.5%	0.15	-20.3%	0.15	NO
Wellington North Power Inc.	13.6%	0.45	12.5%	0.45	NO
West Coast Huron Energy Inc.	31.7%	0.60	29.4%	0.60	NO
Westario Power Inc.	-3.4%	0.30	-4.2%	0.30	NO
Whitby Hydro Electric Corporation	-2.2%	0.30	-3.9%	0.30	NO

Table 5

Stretch Factor Assignments by Group

Group I	Group II		Group III		Group IV	Group V
Stretch Factor = 0%	Stretch Factor = 0.15%		Stretch Factor = 0.30%		Stretch Factor = 0.45%	Stretch Factor = 0.60%
Cooperative Hydro Embrun Inc.	Burlington Hydro Inc.	Lakefront Utilities Inc.	Alectra Utilities Corporation	Niagara-on-the-Lake Hydro Inc.	Atikokan Hydro Inc.	Algoma Power Inc.
E.L.K. Energy Inc.	Energy+ Inc.	Lakeland Power Distribution Ltd.	Bluewater Power Distribution Corporation	North Bay Hydro Distribution Limited	Canadian Niagara Power Inc.	West Coast Huron Energy Inc.
Halton Hills Hydro Inc.	Entegrus Powerlines Inc.	Milton Hydro Distribution Inc.	Brantford Power Inc.	Oakville Hydro Electricity Distribution Inc.	Chapleau Public Utilities Corporation	Toronto Hydro-Electric System Limited
Hydro Hawkesbury Inc.	EPCOR Electricity Distribution Ontario Inc.	Newmarket-Tay Power Distribution Ltd.	Centre Wellington Hydro Ltd.	Orillia Power Distribution Corporation	Festival Hydro Inc.	
Northern Ontario Wires Inc.	Espanola Regional Hydro Distribution Corporation	Orangeville Hydro Limited	EnWin Utilities Ltd.	Peterborough Distribution Incorporated	Hydro One Networks Inc.	
Wasaga Distribution Inc.	Essex Powerlines Corporation	Oshawa PUC Networks Inc.	ERTH Power Corporation	Renfrew Hydro Inc.	Hydro Ottawa Limited	
	Grimsby Power Incorporated	Ottawa River Power Corporation	Fort Frances Power Corporation	Rideau St. Lawrence Distribution Inc.	PUC Distribution Inc.	
	Hearst Power Distribution Company Limited	Kenora Hydro Electric Corporation Ltd.	Greater Sudbury Hydro Inc.	Sioux Lookout Hydro Inc.	Thunder Bay Hydro Electricity Distribution Inc.	
	Hydro 2000 Inc.	Welland Hydro-Electric System Corp.	Guelph Hydro Electric Systems Inc.	Tillsonburg Hydro Inc.	Wellington North Power Inc.	
	Kitchener-Wilmot Hydro Inc.		Innpower Corporation	Veridian Connections Inc.		
			Kingston Hydro Corporation	Waterloo North Hydro Inc.		
			London Hydro Inc.	Westario Power Inc.		
			Niagara Peninsula Energy Inc.	Whitby Hydro Electric Corporation		