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Ontario Energy Board
27th Floor
2300 Yonge Street
Toronto, Ontario
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ATT: Kirsten Walli, Secretary

June 25, 2007.

Dear Ms. Walli,

Re: Comparison of Distributor Costs
Consultation on Consultant's Report
Board File No.: EB-2006-0268

In accordance with the OEB's e mail and web posting of April 27, 2007, ECMI submits is comments on the above noted matter.

Three paper copies are enclosed. Electronic copies in both Adobe Acrobat and Word have been sent this date by email to boardsec@oeb.gov.on.ca.

Requested contact details are as follows:-
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Respectfully submitted for the Board's consideration,

Original signed by R. White

Roger White
President

Once again, the analysis underpinning the establishment of peer groups or cohorts fails to start with the fundamental consideration of the needs of and value to customers. Failure to maintain these fundamental considerations in the establishment of peer groups can readily produce perverse results. When attempting to determine the needs of and value to customers, these considerations must be tested against the customer's alternatives from a customer perspective. There is significant diversity in customers. This recognition would reasonably be expected to result in the Board abandoning the one shoe fits all approach for this process.

On page 75 of the report "Benchmarking The Costs Of Ontario Power Distributors", by the Pacific Economics Group (PEG) (Appendix B), item 10 states that the dominant driver for LDC costs is the number of customers. Appendix A to this submission indicates that customer count compared with total OM&A produces OM&A per customer which does not indicate economies of scale.

In general, in Appendix B of the report there is little or no indication as how the peer groups were initially established or what weighting was given to each of the 11 factors (included in Appendix B) used by Board Staff to establish their peer groups. The exception to this comment are the comments by PEG in the report's executive summary.

The PEG reports states on Pages V and VI that:
"Board staff have developed an approach to the benchmarking of power distributor cost that features simple unit cost metrics (*e.g.* cost per customer). The peer groups do a good job of sorting utilities based on differences in the operating scale, input prices, and forestation that they face. However, utilities in some groups have widely varying degrees of customer density. This approach should be upgraded if it is to be used in ratemaking. Two steps are especially essential:

1. Focus on the cost of total OM&A expenses for the next round of rate cases.
2. Instead of simple unit cost metrics, use unit cost indexes with multidimensional output quantity treatments such as those that we have developed from our econometric work. The Board should also consider replacing or supplementing indexing with direct econometric cost benchmarking. All of these steps can be implemented now in time for use in the upcoming EDR applications.

In choosing between the benchmarking methods that have been developed for its consideration, the Board must balance the criteria of benchmarking accuracy and the complexity of methods. The direct econometric approach to benchmarking is more complex than cost indexing but has a number of advantages that include greater accuracy and the availability of sensible statistical tests of efficiency hypotheses. Regulators in several countries have concluded that the advantages of sophistication generally outweigh the advantages of simplicity when benchmarking is used in ratemaking."

At the bottom of page V in PEG's executive summary it suggests that density warrants more consideration than the 3 prime drivers apparently used by Board Staff which include:

- "the operating scale,
- input prices, and
- forestation"

(Bullet format for ease of reading)

ECMI thanks PEG for the only real indication of the priorities and weighting applied by Board Staff in the establishment of the initial peer groups.

Forestation is an interesting comment. How forestation is determined and measured can be crucial to testing the validity of it as a cost driver. If an LDC has 100% underground with a huge number of trees, the forestation may be high but the OM&A costs associated therewith could readily be expected to be low. Similarly the age of the LDC's distribution system and associated subdivisions are probably a much greater driver as urban development is often referred to as the creator of the urban desert in modern subdivision developments.

If PEG thinks that Board Staff used 3 prime drivers as indicated above, then clearly a complete review of the 11 items in Appendix B which were utilised to establish the initial peer groups would not only be helpful but is in fact essential. Asking for PEG's comments on the Board staff analysis and then inviting interested parties to comment on PEG's comments leaves the Board staff analysis unscrutinised. The lack of the opportunity to fully understand Board staff analysis and initial assumptions results in a flawed process.

A complete disclosure of the Board Staff analysis used to establish the peer groups is essential to add meaning to both PEG's analysis and its process. The fundamental lack of transparency in this key part of the process eliminates any validity which the process might produce and therefore cannot be judged to be either fair or equitable.

In addition to the preceding comments, ECMI has identified 5 key areas of interest in the PEG report and has provided specific comments on each of these areas following this summary:

1. ECMI agrees with PEG that capital employed is an important if not a primary aspect of identifying customer costs and benefits which seem to be fundamental in comparing LDCs. While the market replacement cost of assets is one way of establishing a basis for comparison, if depreciation is valid it seems that depreciated or book value may be the most effective way of analysing the capital employed as this depreciated value is utilised in establishing the return on assets employed paid by the customers. One cannot take capital employed in isolation from how and why that capital is employed. Such an approach eliminates the validity of using capital employed for a basis for establishing cohorts.

2. ECMI concurs with the PEG report that sufficient weight customer density is critical in the establishment of peer groups.

3. ECMI also concurs that the extent of underground facilities is an important consideration but should not be considered in isolation the age of the underground facilities.

4. Volume considerations are important but the PEG analysis fails to adequately consider the parameters underpinning the delivered volumes and how those parameters might be quite different from a direct dependency on number of customers. The scale related drivers identified in Pages IV and V of the Peg report linking total LDC volumes and number of customers may be unsupported when large loads serving individual customers can materially change one of the key parameters.

5. The comments included below relating to volumes and scale drivers leave ECMI concerned that the developments of the weightings used in establishing productivity indexes are not explained. The notion that the words "econometric estimates" should make all mortals quake in fear and be quiet should not substitute for a valid explanation.

1. Consideration of Capital

The PEG report fails to consider the capital employed to serve the customers. The cost of capital is an important part of the costs attributable to customers through the Ontario Energy Board regulatory practices. The age of the plant can provide a reasonable explanation for increased or reduced operation and maintenance costs (O&M costs). It can further explain higher administration costs if the LDC has higher levels of internal staff to scrutinise supervise, manage etc. Similarly, older plant can require greater administrative effort and associated costs if the LDC contracts out for maintaining and/or operation of the older distribution facilities.

A distribution system employing loop design or network like design techniques can result in a more capital intensive system. Such a system, if it were independent of density, could well produce a significantly higher level of reliability than a radial system. This higher level of reliability may be of material value to customers and worthy of higher rate levels as a result of both capital employed and O&M costs associated with that capital. In addition, a loop design system may result in lower levels of outage and lower O&M costs because of the ability to sectionalise and isolate the faulted section so that repairs can be performed on an unenergized section of the system. The value to customers is not recognised in the PEG report. The cost of this value to customers may result in a requirement for an LDC to retain higher levels of standby resources to deal with outage situations. Similarly a 24/7 operations and control centre may result in higher OM&A costs but permit reduced response and outage times.

When one is considering value to customers, the tax rate faced by the LDC should be considered. A small LDC with a relatively low net income will have approximately ½ the taxes of a large LDC. This recognised tax difference is reflected in the rates approved by the OEB and charged by the LDC. This can result in a material difference in the rates payable by the customers. Failure to consider this customer benefit may reduce the <u>value</u> to customers which might be derived from the PEG report.

2 Density
The OEB should recognise that age of assets and customer density may well be the most appropriate considerations for defining a cohort.

Failure to adequately consider customer density as a prime factor. It is apparent that some of the fallout for some of the LDCs than in the establishment of the peer groups customer density per km of line failed to have sufficient weighting to recognise how fundamental a cost driver for OM& A for Ontario distributors. From the wording in Appendix B, density was secondary consideration, if at all.

If density is enough reason to exclude HONI and enough reason to establish Great Lakes Power as a separate cohort, then clearly it is essential that density dominate the establishment of cohorts and that a simple or complex or other type of “scanning” is hardly sufficient consideration when establishing a key measuring stick for LDCs. Measuring sticks, regardless of the best intent often turn into punishing canes in an inappropriate classroom.

3. Underground
Similarly, the extent and particularly the age of underground facilities may likewise be next on the list for considerations in defining cohorts. Older underground facilities have a higher incidence of failure which results in higher maintenance costs than would be for an equivalent capacity overhead system repair. Underground in the Ontario market is most prevalent in assets constructed after 1970. Even in Ontario, underground installed prior to the mid 1950’s has a much higher failure rate than new underground installations. With the introduction of aluminum underground, cross linked polyethylene cables which were initially used for primary underground installations developed early unanticipated failures due to the nature of the insulating material and the method of installation. More recent underground installations may benefit from technological/material changes and improvements in installation techniques. Regardless, it is apparent that the degree of underground exclusive of age considerations is insufficient to be a prime driver in cohort determination. Lack of knowledge about the history in the Ontario system can readily punish an LDC for situations beyond any reasonable level of its control. Failure to fully recognise these underpinning fundamental cost drivers may make this study unhelpful if one is hoping to use the proposed cohorts as a significant consideration in establishing either allowed OM & A in the rates or in some way establish the rates or allowed return for any LDC.

4. Volumes
The following comments demonstrate the high level of risk in utilising average delivery cost per customer or some similar metric in estimating or otherwise determining possible value to customers or establishing peer groups.

While the report purports to consider delivery volumes, large deliveries to individual customers near transformer stations may produce high deliveries with very low O&M costs and likewise very low capital costs. Failure to consider load distribution and utilise only numbers like average customer density can readily lead to erroneous conclusions about the costs incurred by an individual LDC. Similarly, an LDC may have one delivery point which supplies an apartment building which may have 500 or 600 individually metered LDC customers. This latter situation will produce apparently higher density while an individual industrial customer using the same amount of energy will produce a comparable lower density. The LDC’s delivery cost and external elements exposure (whether short term weather effects or long term ageing effects) can be identical for these 2 situations.

These comments underpin ECMI's concerns regarding the use of scale related drivers. For ease of reference the quote establishing the apparent reliance on volume relating to number of customers is included from pages IV and V of the PEG report:

"All of the business condition variables in the models have statistically significant and sensibly signed parameter estimates. The explanatory power of the models is high. The results suggest that there are at least three scale-related drivers of distributor cost --- delivery volume, the number of customers served, and system extensiveness--- as well as miscellaneous other drivers that include undergrounding and forestation."

5. Productivity Indices

There is no explanation as to the specific basis for the "econometric estimates" which produce the weightings or specifically how they are employed to establish these "appreciable economies of scale in Ontario power distribution after controlling for other business conditions."
Ref page V of report

This type of self serving analysis is similar to the analysis that produced higher quality education in Ontario as a direct result of reducing the money input into the education system.

Similarly, the PEG report has not explained how the analysis controlled for delivery conditions (ref Page V of report). This fact leaves the statement without credibility.

For ease of reference the following quote from Page V of the PEG report is included:

"We calculated unit cost and productivity indexes for the sampled distributors using multi-dimensional output quantity treatments. These treatments take a weighted average of comparisons of
delivery volumes, 24%
system extensiveness, 15%
and the number of customers served. 61%
The weights for these output dimensions (24 %, 15%, and 61% respectively) are based on ***our*** *econometric estimates of their cost impact. We have used the econometric models, additionally, to directly benchmark the costs of the distributors."*
Ref page V of report (our emphasis)

Overall Conclusion

The initial flaw in the PEG report appears to be starting with a non transparent Board staff analysis and approach. Other flaws may stem from a lack of knowledge about Ontario distributors underpinning the assumption that there is sufficient homogeneity to make the sample size large enough for the analysis being performed. The analysis and underpinning assumptions missed too much and even with the adjustments proposed by PEG will not produce a robust regulatory tool nor should these results be utilised to fast track any LDC's regulatory submissions.

If benchmarking is to be considered as part of any future incentive based regulation program, the specific attributes underpinning the benchmarking process would have to be assessed for validity to produce any credible incentive regulation application. ECMI wishes to remind the Board that regulation is primarily for the protection of customers and if the failure to establish credible incentive regulation expectations based on value (not price) to customers will result in a flawed process with or without the use of any process including this flawed benchmarking study. In the end, if a system is degraded by an incentive based regulation plan, it will ultimately be the customers who pay for capital or OM&A costs associated with restoring the reliability of the LDC's system. This fact is demonstrated by the recent decision to allow Hydro One Networks to retain at least a share of earnings in excess of what would be allowed by the normal regulatory practices which underpinned the approval of the rates which produced excess earnings in the first place.

Appendix A

Comparison Table showing OM & A and OM & A per customer and ranking by customer count

	Colours designate cohorts established by Board staff and adjusted by PEG	Average OM&A Expenses From Table 5 of report (Pages 59 & 60 not numbered)	4 Yr Average OM&A Costs per customer From Pages 78 & 79 of Report (not numbered)	Customer counts Derived from previous two columns	Rank by customer count	Rank by OM & A costs /customer
LCS	Toronto Hydro-Electric System	138,488,976	$240	577,037	1	59
LCS	Hydro Ottawa	37,805,068	$161	234,814	2	9
LCS	Horizon Utilities	31,469,808	$155	203,031	3	7
LCS	Powerstream	33,730,504	$179	188,439	4	16
LCS	Enersource Hydro Mississauga	35,667,848	$219	162,867	5	48
LCS	London Hydro	20,321,872	$158	128,619	6	8
LCS	Hydro One Brampton Networks	13,370,715	$136	98,314	7	4
LCS	Veridian Connections	19,922,136	$204	97,658	8	32
LCS	ENWIN Powerlines	20,080,970	$287	69,969	9	76
GTA	Kitchener-Wilmot Hydro	9,351,437	$138	67,764	10	5
GTA	Barrie Hydro Distribution	7,813,820	$134	58,312	11	2
LN	Thunder Bay Hydro Electricity Dist.	10,287,890	$230	44,730	12	55
GTA	Oakville Hydro Electricity Distribution	9,223,560	$209	44,132	13	36
GTA	Cambridge and North Dumfries Hydro	7,104,172	$162	43,853	14	10
GTA	Burlington Hydro	9,539,784	$218	43,760	15	45
GTA	Waterloo North Hydro	8,171,374	$188	43,465	16	23
GTA	Guelph Hydro Electric Systems	7,535,517	$187	40,297	17	22
LN	Greater Sudbury Hydro	8,171,498	$207	39,476	18	35
GTA	Brantford Power	6,180,431	$190	32,529	19	24

GTA	Whitby Hydro Electric	6,584,501	$205	32,120	20	34
GTA	Niagara Falls Hydro	7,093,752	$221	32,098	21	50
LN	PUC Distribution	6,254,896	$204	30,661	22	33
E	Peterborough Distribution	5,103,207	$169	30,196	23	14
SMT	Chatham-Kent Hydro	4,698,529	$163	28,825	24	12
SMT	Bluewater Power Distribution	7,072,941	$254	27,846	25	64
SMT	Essex Powerlines	5,561,232	$210	26,482	26	38
GTA	Newmarket Hydro	5,165,882	$220	23,481	27	49
E	Kingston Electricity Distribution	4,903,757	$212	23,131	28	40
LN	North Bay Hydro Distribution	4,678,187	$223	20,978	29	51
GTA	Welland Hydro-Electric System	3,693,122	$186	19,855	30	21
SMT	Haldimand County Hydro	4,978,903	$255	19,525	31	65
SMT	Westario Power	4,157,664	$218	19,072	32	47
SST	Halton Hills Hydro	3,744,491	$213	17,580	33	43
SST	Norfolk Power Distribution	3,826,365	$228	16,782	34	54
SMT	Festival Hydro	2,954,023	$179	16,503	35	17
GTA	Milton Hydro Distribution	3,572,770	$225	15,879	36	52
SST	Peninsula West Utilities	3,895,811	$274	14,218	37	73
SMT	St. Thomas Energy	2,549,829	$184	13,858	38	20
SMT	Erie Thames Powerlines	3,755,379	$286	13,131	39	75
SMT	Woodstock Hydro Services	2,746,297	$210	13,078	40	37
SST	COLLUS Power	2,463,634	$190	12,966	41	25
SMT	Fort Erie (CNP)	3,148,520	$264	11,926	42	68
SMT	Innisfil Hydro Distribution Systems	2,465,220	$212	11,628	43	41
SMT	Orillia Power Distribution	2,629,754	$239	11,003	44	58
LN	Great Lakes Power	6,100,416	$606	10,067	45	84
SMT	E.L.K. Energy	1,679,279	$173	9,707	46	15
SN	Ottawa River Power	1,854,822	$192	9,661	47	28

SMT	Wasaga Distribution	1,292,945	$134	9,649	48	3
SST	Orangeville Hydro	1,651,565	$179	9,227	49	18
SST	Grimsby Power	1,314,250	$148	8,880	50	6
E	Lakefront Utilities	1,307,426	$163	8,021	51	11
SN	Lakeland Power Distribution	1,931,900	$248	7,790	52	61
SST	Brant County Power	2,603,177	$340	7,656	53	81
SST	Niagara-on-the-Lake Hydro	1,267,288	$196	6,466	54	30
SMT	Middlesex Power Distribution	1,359,979	$218	6,238	55	46
SST	Tillsonburg Hydro	1,302,458	$212	6,144	56	42
SMT	Port Colborne (CNP)	1,447,646	$236	6,134	57	56
SN	Northern Ontario Wires	1,725,352	$283	6,097	58	74
SST	Midland Power Utility	1,598,480	$270	5,920	59	70
SN	Kenora Hydro Electric	1,210,292	$211	5,736	60	39
GTA	Centre Wellington Hydro	1,420,028	$251	5,657	61	63
E	Rideau St. Lawrence Distribution	1,152,996	$216	5,338	62	44
E	Hydro Hawkesbury	656,384	$133	4,935	63	1
SST	Tay Hydro Electric Distribution	736,780	$191	3,857	64	27
E	Renfrew Hydro	719,735	$191	3,768	65	26
SN	Fort Frances Power	911,479	$249	3,661	66	62
LN	West Nipissing Energy Services	720,306	$197	3,656	67	31
SST	West Coast Huron Energy	1,148,015	$314	3,656	68	79
SN	Espanola Regional Hydro Distribution	802,114	$246	3,261	69	60
SST	Wellington North Power	847,699	$265	3,199	70	69
E	Parry Sound Power	856,835	$274	3,127	71	72
SN	Sioux Lookout Hydro	831,596	$314	2,648	72	78
SN	Hearst Power Distribution	512,184	$195	2,627	73	29
SST	West Perth Power	450,079	$255	1,765	74	66
SN	Atikokan Hydro	738,959	$428	1,727	75	83

E	Cooperative Hydro Embrun	302,333	$184	1,643	76	19
SST	Clinton Power	354,117	$227	1,560	77	53
SN	Chapleau Public Utilities	467,979	$367	1,275	78	82
E	Hydro 2000	170,263	$165	1,032	79	13
SN	Terrace Bay Superior Wires	278,342	$310	898	80	77
SST	Grand Valley Energy	171,219	$259	661	81	67
SST	Dutton Hydro	155,646	$273	570	82	71
SST	Newbury Power	42,155	$237	178	83	57