Getting it Right: Submission of the Coalition for an Effective Incentive Rate Mechanism to OEB's Consultation on 3rd Generation IRM

Introduction:

On November 21, 2008, the Board Secretary wrote to Ontario's licensed electricity distributors and other interested parties with an invitation to comment on certain material prepared by Board staff and the Pacific Economics Group ("PEG") pertaining to the Board's 3rd Generation Incentive Regulation ("3rd Generation IRM") initiative.

In that letter, the Secretary referred to the Board's September 17, 2008, "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," and noted that "In that Report, the Board stated its intention to undertake further work on the model it will use to assign stretch factors to distributors and to consult with stakeholders to identify whether it can improve the grouping approach and further reduce the potential for misclassification in the two OM&A benchmarking evaluations. The purpose of this letter is to initiate that consultation."

The Coalition for an Effective Incentive Rate Mechanism ("CEIRM") is pleased to make this submission to the Board's consultation on 3rd Generation IRM (EB-2007-0673). CEIRM represents 22 local electricity distribution companies ("LDCs"), which together serve 51% of all 4.6 million customers in Ontario.[1] In addition, we reflect a cross-section of small and large, northern and southern, and rural, suburban and urban LDCs. (A full list of the signatory LDCs is included in Appendix 1 along with the coalition's contact information.) Five attachments are also included with this submission, including CEIRM's presentation to the Electricity Distributors Association.[2]

As a group, CEIRM welcomes and supports the principles of IRM and is pleased that the Board, in announcing the further consultation in September of this year, is seeking to ensure that the intended results materialize. We commend the progress the Board and Board Staff have made to date and we are appreciative of stakeholder contributions to previous consultations, including those from the LDCs that have contributed to this submission.

We believe that there exist opportunities for workable improvements to the effectiveness and fairness of the proposed 3rd Generation IRM framework, including, as noted in the Board Secretary's letter of November 21st, from having stakeholders "identify whether [the Board] can improve the grouping approach and further reduce the potential for misclassification in the two OM&A benchmarking evaluations."

In this submission, we are pleased to provide nine straightforward and practical recommendations that we suggest will improve the rigour of the IRM framework greatly.

[1] CEIRM also represents 69% of all customers served by LDCs other than Hydro One Networks.
[2] Please see Attachment 1, CEIRM Presentation to EDA, December 9, 2008.

They are presented, with detailed rationales, under the following three general groupings:

- Level Playing Field;
- Meaningful Peer Groups; and
- Data Quality Issues

CEIRM's goal in making this submission is both to assist the Board in making its 3rd Generation IRM framework as effective as possible and to ensure customers of all LDCs are well served by IRM. With 83 LDCs in Ontario, ranging in size from less than 1,000 to over one million customers, we submit that benchmarking and incentive regulation are exactly what is needed to simplify the regulatory process. We see the Board's IRM initiative as evidence that the "light-handed" regulation behind the *Energy Competition Act, 1998*, is coming to fruition for LDCs.

From CEIRM's perspective, a well functioning IRM framework is the kind of proxy for competition that protects the interests of customers and lowers the regulatory burden of running an LDC for shareholders. The human and financial resources consumed in 2008 cost of service applications for approximately one-third of the LDCs, with the other two-thirds to follow in 2009 and 2010, clearly illustrate that those costs are not sustainable. CEIRM's members are supportive of IRM and welcome the change.

However, in moving to an incentive framework with real financial consequences, CEIRM submits that it is imperative that the benchmarking methodology and application of data be sufficiently rigorous to provide fair and equitable treatment. For this reason, we are encouraged by the Board's interest in this further round of consultation.

In our review of the material released by the Board and PEG for this consultation, we have identified a number of issues that indicate that the benchmarking within the IRM framework requires additional refinement. Our two main concerns are:

- The IRM benchmarking unfairly and unnecessarily 'bonuses' significant numbers of LDCs at the expense of the rest; and
- The current IRM peer grouping criteria create distortions that better and more suitable criteria would avoid and/or overcome.

These issues are extremely important. The ranking results and assignment of "stretch factors" affect the revenues that will enable LDCs to operate and maintain their distribution systems. They, therefore, have potential implications for reliability, not just financial implications for LDCs, their customers and their shareholders. There are real consequences to an LDC being incorrectly assigned a more stringent stretch factor than what is deserved because of imperfections in the benchmarking.

The other reason these issues are important is that the IRM framework provides signals as to which LDCs are "superior performers". If the framework is not recognizing the real industry leaders, the consequence is that it will not simplify the regulatory process.

Instead of matters being streamlined, misclassified LDCs will need to return more frequently with cost of service rate applications, if the alternative is the annual mechanistic application of an inappropriate stretch factor for a period of several years. Conversely, LDCs that have been misclassified as superior performers will not receive the necessary signals that would identify the need for efficiency improvements.

With our objective being to make the IRM framework effective and only a small portion of LDCs being affected by the IRM stretch factors in 2009, there is a unique opportunity of "getting it right" with respect to IRM at the outset of the 3rd Generation IRM period. We would encourage the Board to implement those of our recommendations that are practicable for 2009, and to begin work immediately toward improving the effectiveness of IRM for 2010, when a new wave of LDCs will be affected by the stretch factor.

It is in the spirit of improvement and effectiveness for IRM that we offer these nine recommendations. We look forward to your consideration of these recommendations and the opportunity to work with you for the betterment of this valuable process.

Compendium of Recommendations:

Recommendation 1 – Treatment of LV Costs:

"Ensure the respective 'LV' (low voltage or sub-transmission) costs paid by LDCs in the benchmarked costs of all LDCs reflect like-for-like comparisons of LDCs, including ensuring that all costs are accounted for and rely on appropriate cost allocation methodologies where specific data is not available, thereby giving recognition to the reduced LDC operating costs when services are provided by host distributors through the cost of power when supplying 'embedded' distributors."

Recommendation 2 – Exclusion of LDC HV Transformation Costs:

"Exclude (pull out) the operating costs related to LDC-owned high-voltage transformation assets in the benchmarked costs of LDCs in order to create a like-for-like LDC comparison, thereby giving recognition to the higher operating costs than would otherwise be the case for LDCs where these services are provided for in the cost of power by licensed transmission providers."

Recommendation 3 – Recognition of Capital in Benchmarking:

"Provide benchmarking recognition for LDC differences on capital, particularly to address the asset lifecycle stages and the impact of growth but also the more robust nature of benchmarking if based on total cost, recognizing that Ontario's LDCs largely follow municipal boundaries that in many cases delimit high-growth LDCs with relatively new systems from more static growth LDCs oriented to replacement and maintenance projects and that this character to the LDC sector will limit the effectiveness of benchmarking that does not consider capital."

Recommendation 4 – Abandon Scale as a Peer Group Criterion:

“Abandon peer grouping based on scale, recognizing that scale is choice of LDC shareholders and creating scale peer groups is a vehicle for protecting inefficient scale of LDC administration costs.”

Recommendation 5 – Abandon Undergrounding as a Peer Group Criterion:

“Abandon peer grouping based on degree of undergrounding and geography except for Canadian Shield, recognizing these are not significant differentiators of LDC performance in the existing peer groups when measured on O&M costs, given that current reliance on OM&A includes ‘administration’ costs that do not relate to costs of undergrounding or geography.”

Recommendation 6 – Adopt Line Density and Cdn. Shield as Peer Group Criteria:

“Adopt line density and retain Canadian Shield as the bases for creating meaningful peer groups, potentially establishing the four ‘customers per kilometre’ cohorts of (1) greater than 50, (2) from 25 to 50, (3) less than 25 for rural (southern and northern), and (4) “Shield urban” from 25 to 60, with the reduction of groups from 12 to 4 improving cohort sample size and the new grouping criteria creating a more natural basis for comparing LDC performance given that customers per kilometre appears to be a greater distinguisher of efficiency and provides a more even distribution of superior performers.”

Recommendation 7 – Treatment of Canadian Shield:

“Restrict the inclusion of LDCs in the northern binary variable for the econometric benchmarking and the unit cost peer grouping to LDCs that are geographically located on the Canadian Shield, which had been the rationale of the consultant, Pacific Economics Group, to ensure that non-Shield LDCs are not artificially and unjustifiably able to become an econometric and unit cost superior performers and to ensure there is no confusion over the purpose of the category.”

Recommendation 8 – Wholesale Customers and LDC Throughput Data:

“Ensure the data set measuring energy throughput efficiency for LDCs addresses all the different permutations for throughput not billed by the LDC, including the energy consumed or generated by wholesale market participants ‘embedded’ in an LDC’s system but not transacted through the LDC and the customer-owned ‘distributed generation’ that fulfils government policy objectives but otherwise displaces throughput, recognizing that all of these variables need to be included for a fair measure of LDC efficiency for there to be a like-for-like comparison of LDCs.”

Recommendation 9 – Data Quality and Rigour:

"Ensure the greatest degree of accuracy in the data inputs used in LDC benchmarking for IRM, possibly as part of the transition to IFRS, recognizing that an LDC should not benefit from the incorrect or non-comparable data being used in a rewards-based benchmarking framework."

Level Playing Field: Rationale for Recommendations

Introduction:

In this group of recommendations, we address three issues that are critical to ensuring there is a level playing field for IRM benchmarking. These recommendations reflect the diversity of distributors in Ontario and the challenges this provides for benchmarking.

The first of the three is the treatment of "LV" (low voltage costs) incurred by distributors embedded in "host" distributors, which are accounted for in their cost of power rather than their own costs. The second is the treatment of high voltage costs ("HV"), where LDCs that own the assets have the costs in their own accounts and LDCs that do not own the assets pay the costs through separate HV charges that are passed through to customers. And, the third is the treatment of capital because varying stages of the life-cycle of assets and growth rates means that some LDCs are capital intensive and others are more maintenance intensive, but only OM&A is benchmarked.

Our purpose in forwarding these recommendations is to make constructive improvements to the IRM benchmarking that will increase the fairness for all LDCs.

Recommendation 1: Treatment of LV Costs

> ***"Ensure the respective 'LV' (low voltage or sub-transmission) costs paid by LDCs in the benchmarked costs of all LDCs reflect like-for-like comparisons of LDCs, including ensuring that all costs are accounted for and rely on appropriate cost allocation methodologies where specific data is not available, thereby giving recognition to the reduced LDC operating costs when services are provided by host distributors through the cost of power when supplying 'embedded' distributors."***

We appreciate the extent of the effort since September 2008 to come up with a framework for the appropriate inclusion of LV charges in the benchmarking data. We are, however, concerned that the reliance on assumptions, judgements and proxies to determine the LV for benchmarking purposes may not be capturing all the costs associated with LV.

As an illustration of the potential for problems on correctly including proxies for LV, we note that 37.5% of the superior performers (6 of 16) in the current econometric results are “small” LDCs with less than 10,000 customers that are wholly or largely reliant on the LV of a “host” distributor. Moreover, we believe these include four of the top six LDCs.[3]

There are good reasons to explain why LV may be one of the least well understood aspects of the LDC sector in Ontario,[4] and so it is easy to see how there could be difficulty in grappling with its measurement and inclusion in benchmarking. Indeed, this point was made in the Coalition of Large Distributors’ submission to the IRM consultation in June 2007.[5]

Now that the methodology for including LV has been discussed in the attachment to the Board Secretary’s letter for the consultation and in PEG’s most recent report, we have a number of questions about the assumptions, judgements and proxy measures. Our concerns are as follows:

1.1 Not All LV Costs Included:

After having difficulty determining LV from LDC filed data, Board Staff acknowledge that they have used the LV charged by Hydro One Networks to other LDCs as the source data to determine the amount of LV in benchmarking costs comparisons.[6]

Our main concern with this approach is that Hydro One is not the only “host” distributor among the LDCs, although it would be the largest. There are cases where Hydro One, itself, is embedded in other “host” distributors, such as in Cambridge and North Dumfries Hydro, and where the host-embedded relationship does not involve Hydro One, such as between Cambridge and North Dumfries Hydro and Waterloo North Hydro.[7] As a result, the total dollars of LV charged by Hydro One would not be the same as total LV charges. In short, this suggests the size of the LV financial pie is larger than just the LV costs that Hydro One charges to its embedded LDCs.

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[3] See PEG, “Sensitivity Analysis on Efficiency Ranking and Cohorts for the 2009 Rate Year: Update,” Table 10. Hereafter, “PEG Update Report”. http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0673/PEG_Updates_20081203.pdf .

[4] LV is an issue in Ontario, where it might not be in other jurisdictions, because there are transmission connected LDCs and LDCs “embedded” in a host LDC’s distribution system, as well as LDCs with both transmission connections and embedded service territory. The significance for benchmarking is that a transmission connected LDC owns the operating costs of distribution stations and sub-transmission feeders whereas “embedded” LDCs do not. The matter is important for benchmarking because, first, fully 70 of the 83 LDCs have LV, with only 13 exclusively transmission connected, and, second, the reliance on LV is uneven among the 70. This is evident when comparing the 83 LDCs with the more than 200 distinct service territories (a result of many being non-contiguous small centres) against transmission system maps. This suggests about 150 service territories are exclusively “embedded”.

[5] Coalition of Large Distributors, “Analysis of the PEG Report by the Coalition of Large Distributors”, June 26, 2007. http://www.oeb.gov.on.ca/documents/cases/EB-2006-0268/cld_peg-comments_20070704.pdf

[6] In the course of this exercise it was determined that LDCs had recorded $14.9 million of LV paid and Hydro One recorded $23 million “billed” to its 70 embedded distributors in 2007, with the difference attributed to two methods being available in the Accounting Procedures Handbook for LDCs recording LV. OEB, “Attachment: Overview of Work Carried Out by Board Staff to Support Pacific Economics Group and Associated Proposal,” p. 6. http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0673/letter_consultation_invitation_20081121.pdf

[7] These LV relationships are noted in: OEB, Cambridge and North Dumfries Hydro EDR 2008, OEB, EB-2007-0900, March 25, 2008, p. 6. http://www.oeb.gov.on.ca/documents/consumers/2008edr/Decisions/dec_Cambridge_NorthDumfries_20080325.pdf

Given the various configurations of LV relationships, it would be helpful if there were an emphasis to correct the data deficiencies before the benchmarking has financial implications for LDCs.

1.2 Confidential Nature of LV Data:

Given the new accounting for LV in LDC benchmarking and the uncertainty as to its correct application, it would be useful if the Hydro One and other LV data could be made public so that stakeholders could provide comment on its implications. The Hydro One LV data was apparently provided on a confidential basis, which is understandable because no LDC can publicly release customer information other than on a confidential basis.

This is, however, a matter of interest for benchmarking, and one where the Board might use its statutory authority to request information from all LDCs. All the other data inputs being used have either been part of the "Reporting and Record-keeping Requirements" ("RRR") publications or disclosed in PEG reports. Only the LV appears to be not for public disclosure. Indeed, the need for confidentiality is curious given that some of the Board's 2008 rate decisions have published the LV costs.[8]

With the recent emphasis on getting LV right, all LDCs might have been requested to provide the correct LV data inputs, rather than relying on Hydro One for its part of the LV picture. This would have provided better potential for a more definitive picture of LV.

1.3 O&M, not OM&A:

In determining the assignment of LV to embedded LDCs, the focus appears to have been on pegging the O&M portion of the LV as the appropriate cost to benchmark. We accept the need to separate out capital, given that capital is not part of the benchmarking framework at this time, but we are concerned that all of administration is excluded.

As we understand the exercise to arrive at the O&M amounts, Hydro One's LV revenue requirement was determined to be 52% capital-related and, 48% OM&A; and, of the latter, O&M was 26% and Administration was 22%. In essence, for every $100,000 of LV revenue requirement, there is $26,000 of benchmarked costs (before any cost allocation adjustment).

While there may be other issues in this manner of determining LV, we do not follow the rationale provided for separating out Administration from O&M, leaving O&M the only portion of the LV charge to embedded LDCs. The rationale is: "Staff does not believe that Hydro One's administration costs to manage its extensive business in Ontario would be indicative of those that might be incurred by a smaller embedded distributor."

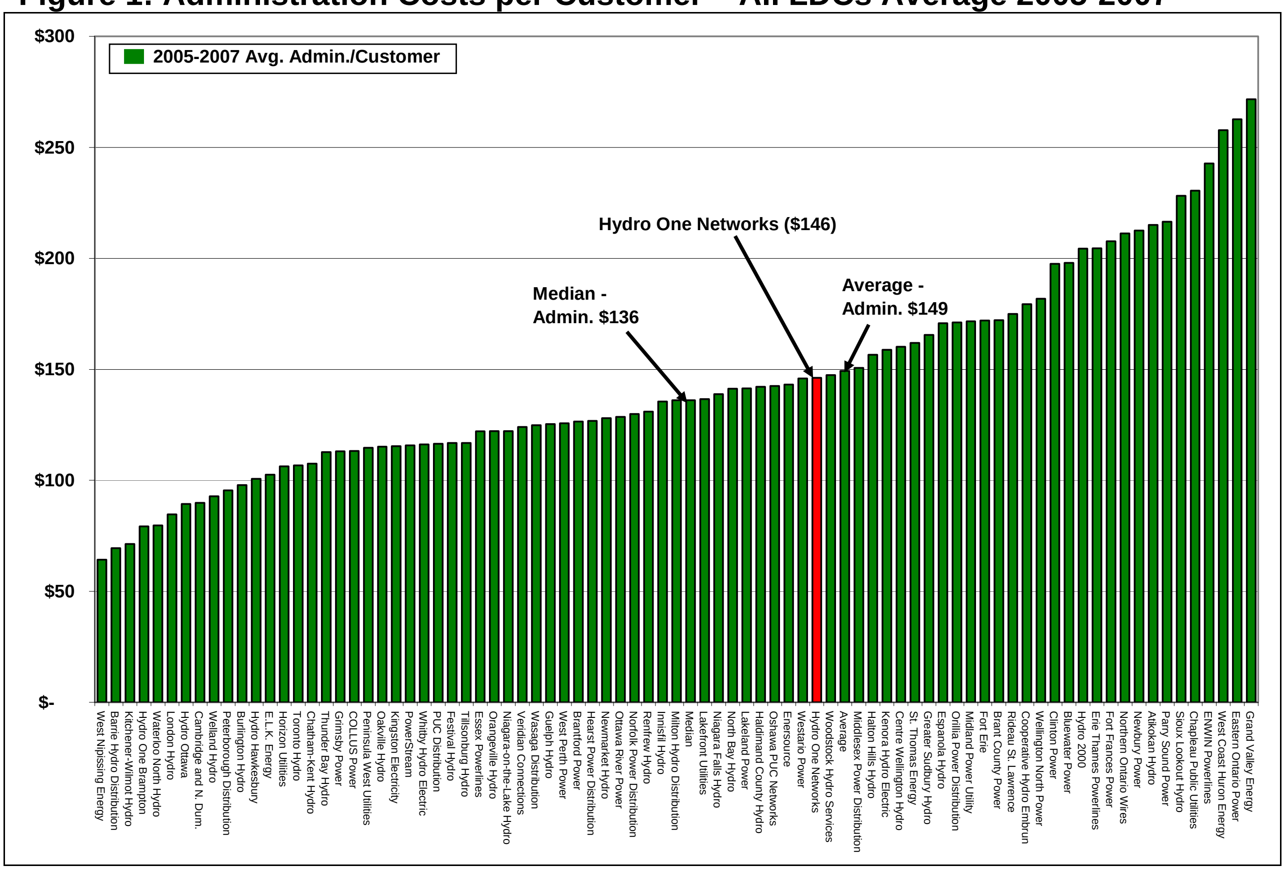
[8] See, for example, Hydro 2000's 2008 EDR. http://www.oeb.gov.on.ca/documents/cases/EB-2007-0704/dec_Hydro_2000_20080314.pdf

The position taken implicitly asserts that Hydro One's allocation of administration costs to its LV customer class is incorrect and attributes to that class costs that do not belong to it. Given that the Board has approved Hydro One's cost allocation, it is incumbent on Staff to demonstrate either that the Board erred or that the purpose for which the Board approved that allocation is fundamentally different than the present purpose.

From our perspective, it is not clear that Hydro One's "administration" costs are not "indicative" of the costs of other LDCs, and in many cases they actually appear to be lower. Moreover, not all 70 LDCs paying LV can be the "smaller" ones suggested if only 33 of all 83 LDCs have less than 10,000 customers. Clearly there are administrative costs associated with owning LV assets, such as insurance costs, property taxes and salaries of middle managers.

Figure 1 provides an illustration of the three-year average "administration" of all LDCs over 2005-2007 with Hydro One highlighted. What the data shows is that Hydro One's administration cost, at $146 per customer per year, is actually below the LDC average of $149 and just above the LDC median of $136, meaning almost as many LDCs are more expensive as less expensive than Hydro One.

Figure 1: Administration Costs per Customer – All LDCs Average 2005-2007



Source: OEB, Reporting and Record-keeping Requirements, 2005-2007. (Hereafter, "RRR").

The data in Figure 1 would suggest it is not appropriate to exclude Hydro One's "administration" costs from LV calculations based on its cost of administration compared with other LDCs. Moreover, of the 31 LDCs with higher Administration costs than Hydro One, 19 are "small" LDCs and only one is "large". If Hydro One's actual administration cost is a burden to the LDCs with lower costs, a possible alternative would be to create a proxy of the embedded LDC's administration in place of the administration portion of Hydro One's LV charges rather than to level no administration charge at all.

While not an argument presented by Board Staff or PEG, Hydro One's administration costs might reasonably be said to be mostly for billing and collection activities. This means at least some of the administration costs are inappropriate for benchmarking LV for embedded distributors, but two potential alternatives besides just O&M exists. One would be to require Hydro One to undertake a cost allocation or establish a proxy for Hydro One's actual administration for LV customers. Another would be to develop a proxy cost for the embedded LDCs to have performed the LV, which would not affect all LDCs the same. In this case, there may be a larger burden for LDCs that are wholly embedded versus those that are transmission connected with a smaller reliance on LV.

1.4 Hydro One Revenue/Cost Ratio Calculation for LV:

The proxy cost for LV in the benchmarking also has factored in a revenue-to-cost ratio adjustment of 2.35, based on Hydro One's revenue-to-cost ratio for its "ST" (sub-transmission) class of customers, which include LV customers.[9] As show in Table 1, when the 26% or $26,000 of every $100,000 of LV is divided by the cost allocation adjustment, the new O&M figure becomes 11% or $11,064 of every $100,000.

Table 1: Assumptions in LV Cost Determination in Benchmarking

LV Assumption Options: **("R/C" – revenue-to-cost)**	**OM&A alone**	**OM&A / 1.3 R/C ratio[1]**	**O&M / 1.3 R/C ratio[1]**	**O&M / 2.35 R/C ratio[2]**
Proxy LV Payment	$100,000	$100,000	$100,000	$100,000
Capital (52%)	$52,000	$52,000	$52,000	$52,000
OM&A portion (48%)	**$48,000**	**$48,000**	$48,000	$48,000
Administration (22%)			$22,000	$22,000
O&M portion (26%)			**$26,000**	**$26,000**
Proxy LV w/ cost allocation adjustment:	**$48,000**	**$36,923**	**$20,000**	**$11,064**

Notes: [1] 1.3 is Hydro One's stated revenue/cost ratio for its LV class within its broader ST class of customers. [2] 2.35 is Hydro One's revenue/cost ratio for its whole ST class of customers, which includes LV customers.

This outcome, however, possibly gives LV customers an unfair benefit because not all customers within the ST class have the same revenue-to-cost ratios. While the ratio for the ST class as a whole is 2.35, Hydro One is on record as indicating the revenue-to-

[9] See "Hydro One Cost Allocation Study Results," EB-2007-0681, Exhibit G1, Tab 3, Sch.1, p. 2 of 5.

cost ratio for embedded LDC LV customers is 1.3. Indeed, the overall ratio for the ST class apparently got out of kilter through the addition of "T" class customers ("Industrial Commercial Sub-Transmission") to the ST class, which paid much higher rates than LV and other ST class customers, and who chiefly will be the beneficiary of rate reductions in the class as a result of revenue-to-cost ratio adjustments.

In interrogatories for its 2008 rate case (where the ST class revenue-to-cost of 2.35 was disclosed), Hydro One estimated that current revenues at current rates from embedded LDCs were $23.5 million and that revenues required from embedded LDCs based on a revenue cost allocation ratio equal to one were $18 million.[10] This suggests the current revenue-to-cost ratio for embedded LDCs is 1.3 rather than 2.35.

The difference between a cost allocation factor of 2.35 and 1.3 is material. Based on 26% or $26,000 for every $100,000 of LV costs, this is 20% or $20,000 versus 11% or $11,045, which is almost twice as much.

Moreover, assuming the administration cost should be included and the calculation is done on total OM&A rather than O&M, the numbers are even more material. Based on all OM&A, which would be 48% or $48,000 of every $100,000 of LV costs, the cost allocation at 1.3 would make the figures 36.9% and $36,923 versus 20.4% and $20,391 with the cost allocation being 2.35.

1.5 Pooling of LV Costs:

If the LV data were made public, LDCs would be in a much better position to be comfortable with the conclusions to be drawn from the data. The reason for concern is that pooling is a prominent if not the dominant feature of Hydro One's LV arrangements. While this was not as contentious in the former cost of service regulatory framework, it raises some concerns in an IRM framework. Those advantaged by the pooling, which thereby results in lower costs, may benefit from the IRM framework.

An example of an LDC benefiting from the pooling would occur where the embedded LDC's industrial customers are directly serviced by Hydro One's LV feeders and the customers own their own transformation, which is not uncommon. In this case, the local LDC has no O&M costs for serving these customers, bills them through settlements with Hydro One and pays for the LV through the costs of power. Moreover, the embedded LDC receives the benefit of the throughput efficiency from these industrial customers without all of the benchmarked costs to serve these customers. The consequence is that this LDC will benchmark favourably even against other embedded LDCs, such as ones that take power from LV lines at a station that demarks its own network and its own customers.

Since the effect of LV pooling on benchmarking is not an insignificant consideration, the LV data should be published so that stakeholders are able to review these situations

[10] EB-2007-0681, Interrogatories and Responses "H-4-9" and "H-4-10" (Hydro One responding to Energy Cost Management Inc).

and make suggestions that can assist the benchmarking. Initiating a study on the impact and implications of pooling for benchmarking of LDCs would also be advisable.

1.6 Variability of LV Costs Year-to-Year:

The “sensitivity analysis” for LV in benchmarking uses one year of LV data, whereas all other data is based on an average of three years. The justification provided is that, “As a capacity-related charge, the LV charge amounts should be relatively stable from year to year ….”[11] We would argue that this is not necessarily the case because there will be cases where material changes occur, such as with deregistration of wholesale meter points or the transfer of LV assets.

While LV costs are not currently made public, we would argue that they need to be now that they are part of benchmarking. The argument for confidentiality is not persuasive given that the Board itself, through cost of service rate-making decisions, has published LV costs.[12]

1.7 Summary Comments:

In our view, it is important for benchmarking integrity for embedded LDCs to have the correct and appropriate amounts of LV costs. Without the appropriate amounts of LV included, the benchmarking could suggest the relative ranking for LDCs is other than what would be the case in a like-for-like comparison of LDCs.

For the future development of benchmarking, we would recommend a thorough consideration of all the implications of LV to ensure the right drivers are in place. In our view, not only must LV be included in benchmarking for there to be an “apples-to-apples” comparison of LDCs, but also that fairness and transparency dictate the LV methodology must be corrected before the incentive rate mechanism takes further hold.

Recommendation 2: Exclusion of LDC HV Transformation Costs

> ***“Exclude (pull out) the operating costs related to LDC-owned high-voltage transformation assets in the benchmarked costs of LDCs in order to create a like-for-like LDC comparison, thereby giving recognition to the higher operating costs than would otherwise be the case for LDCs where these services are provided for in the cost of power by licensed transmission providers.”***

This recommendation is being offered to address what we believe to be a significant anomaly for LDC benchmarking in Ontario. Most LDCs are part of a high-voltage

[11] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0673/letter_consultation_invitation_20081121.pdf , p. 7.
[12] An example is found in the Board’s decision on Hydro 2000’s 2008 rates This decision reveals that the approved LV costs in 2006 were $106,241 and the accepted LV costs for the purposes of setting 2008 rates is $143,000, which is a 35% increase. This may be explained by Hydro One only beginning to bill embedded LDCs for actual LV costs in May 2006. Until then, Hydro One billed LV based on 1999 billing quantities. http://www.oeb.gov.on.ca/documents/cases/EB-2007-0704/dec_Hydro_2000_20080314.pdf

transformation pool, whether through their high voltage connections or through their "host" distributor. There are, however, at least 18 LDCs fully or partly outside the pooling arrangements that own and operate their own high-voltage transformation assets or stations within the LDC.[13]

In the current benchmarking framework, LDC ownership of high-voltage transformation stations has the potential to cause an "apples and oranges" basis for comparison. Just as the exclusion of LV costs reduces the costs of embedded LDCs in benchmarking, the inclusion of costs for high-voltage transmission stations can increase an LDC's benchmarked costs compared to other LDCs. On this, we note with interest PEG's comment:

> "Our previous econometric research also investigated whether distributors' ownership of high voltage transmission assets impacted OM&A cost performance, but we found that there was no statistically significant relationship between this variable and distributors' OM&A costs. However, PEG believes that further research on this, and on related issues, is warranted in the total cost benchmarking analysis to be undertaken."[14]

While we are yet to be persuaded that the impact of owning transmission assets is not significant for benchmarking, we were not aware that this research had been commissioned. For this reason, we believe that it would be helpful if PEG's previous research were published so we as stakeholders can be satisfied with the results ourselves. That PEG, itself, believes more research is required is encouraging. We would welcome the commissioning of this research with stakeholder input.

The reason for suggesting stakeholder input is so that the Board's consultants can better appreciate the fabric of LDCs and the differences between them, especially on the level playing field issues. Having the opposite impact of the LV phenomenon, the high voltage issue adds costs to LDCs. Most LV connected and transmission connected LDCs are in the transformation pooling arrangements, where these costs are paid for in the cost of power. LDCs with their own high voltage transformation assets, on the other hand, pay the OM&A for the assets in their distribution costs.[15]

The LDCs which have fully or partially opted out of the pooling arrangements will have done so on the basis that they have been able to serve their customers at lower costs than in the pool. In these cases, customers correspondingly receive lower retail transmission rates because the cost of some of the transmission service is included in the distribution rates. In either case, the "network" charge, the portion of the

[13] The list of LDCs that own high voltage assets in the LDC includes, but may not be limited to, Brant County Power, Brantford Power, Cambridge & North Dumfries Hydro, Enwin, Hydro Hawkesbury, Hydro One Brampton Networks, Hydro One Networks Inc., Hydro Ottawa, Kenora Hydro, Kitchener-Wilmot Hydro, Niagara Falls Hydro, Niagara-on-the-Lake Hydro, Norfolk Power, Northern Ontario Wires, PUC Distribution, PowerStream, Toronto Hydro, and Waterloo North Hydro. With 70 LDCs embedded, this list is not an insignificant minority. . OEB, RRR, Row 11, 2007. NB: Veridian is listed in Row 11, but the assets referenced are actually 44 kV sub-transmission assets.

[14] http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0673/PEG_Updates_20081203.pdf

[15] Most LDCs are in Hydro One Networks' high-voltage transformation pooling arrangements. Opting out of the pooling, which became increasingly prevalent in the 1980s and 1990s, will have made sense only for LDCs that are adjacent to transmission lines and that had sufficiently high growth to support a new station without stranding a station that is part of the pooling arrangements.

transmission service that is common to all LDCs, has very little variation. But, in terms of the “line and connection” charges, the charges vary considerably depending on whether the transmission is pooled or owned.

The LDCs that own transformer stations and/or associated transmission are paying less, but absorbing the corresponding costs in their own OM&A. The differences can be material, with the connection charge ranging from $0.000/kWh to above $0.005/kWh for residential customers. For this reason, it is important that the IRM benchmarking exclude their high-voltage transformation costs for them to be on a level playing field with other LDCs.

Going forward, it would be helpful if changes were initiated to separate further the accounting for an LDC’s high-voltage transformation costs from the LDC’s distribution costs so that benchmarking can permit an “apples-to-apples” comparison of LDCs. Specifically, the costs for the maintenance and operation of transformer stations greater than 50 kV (i.e., 115 kV and 230 kV stations as compared to distribution voltage stations) need to be excluded from the benchmarking.[16] In addition, separation of other O&M accounts into transmission and distribution activities would be a helpful further enhancement.

The present inclusion of these high-voltage transformation costs in benchmarking comparisons weakens the apples-to-apples comparison of LDCs. Fairness and transparency dictate these issues need to be corrected before the incentive rate mechanism takes further hold.

Recommendation 3: Recognition of Capital in Benchmarking

> ***“Provide benchmarking recognition for LDC differences on capital, particularly to address the asset lifecycle stages and the impact of growth but also the more robust nature of benchmarking if based on total cost, recognizing that Ontario’s LDCs largely follow municipal boundaries that in many cases delimit high-growth LDCs with relatively new systems from more static growth LDCs oriented to replacement and maintenance projects and that this character to the LDC sector will limit the effectiveness of benchmarking that does not consider capital.”***

This recommendation is being offered to address the potential benchmarking distortions that can result from comparing high-growth LDCs with more static LDCs on only OM&A and not capital, when the lifecycle of the assets can vary greatly from one LDC to the next and total cost of operation provides a more accurate picture for benchmarking.

We could accept the view of not benchmarking on capital if Ontario had a small number of large regional distributors with a healthy mix of emerging and mature areas, large

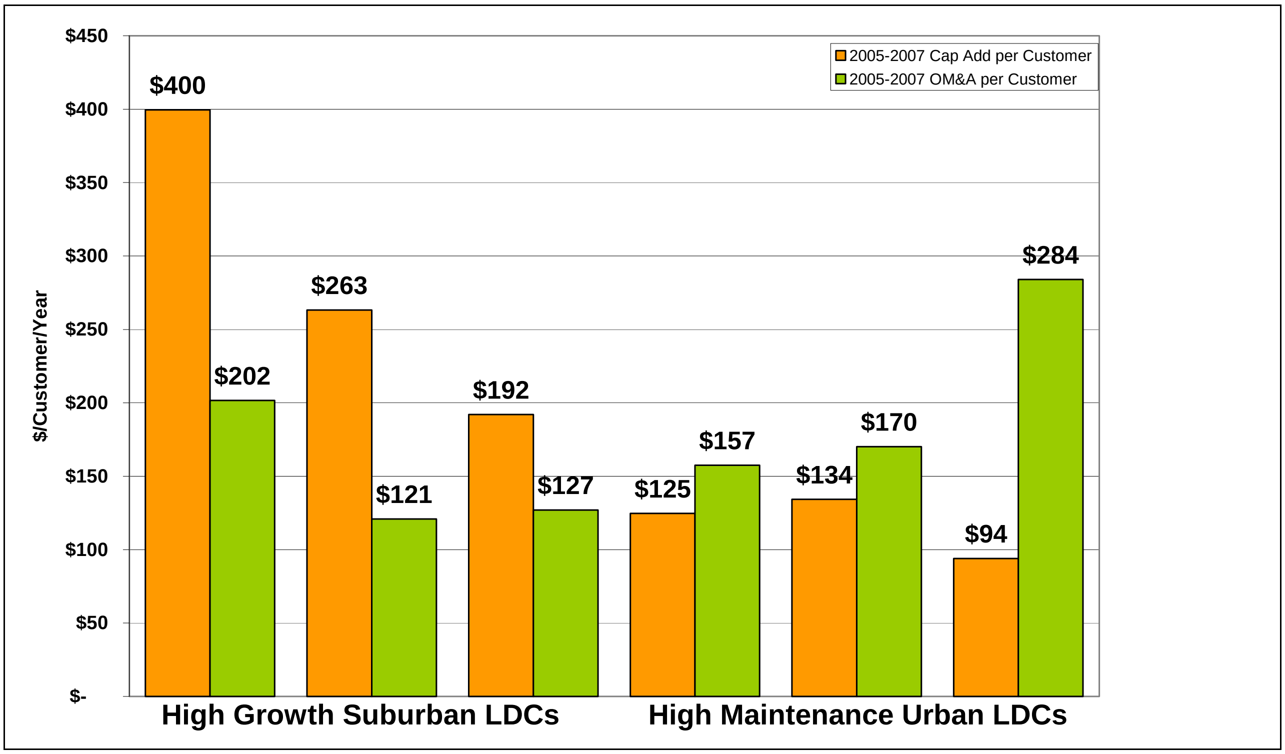
[16] The appropriate Accounting Procedures Handbook accounts for exclusion from benchmarked OM&A would be Accounts 5014, 5015 and 5112.

cities, small towns and rural areas. In such a circumstance, the case could be made that capital issues would be a wash between comparably-sized distributors with a comparable mix of service territories and capital and OM&A challenges.

The contiguity of most of Ontario's LDCs with their municipal shareholders' boundaries, however, means that LDC boundaries in many cases demark high-growth suburban municipalities from low-growth, built-out urban municipalities, large and small. A high-growth suburban LDC generally has newer plant and higher unit costs of capital spending, whereas a low-growth older urban LDC generally has older plant and high unit costs of maintenance spending.

This phenomenon is evident in Figure 2, which provides an illustration of selected high-growth and high-maintenance LDCs. The absence of any benchmarking on capital or total cost means there is a possibility of distortions. The reason is that the benchmarking framework cannot distinguish the impact of expenditures on capital have on expenditures on OM&A, when only OM&A is measured. Capital is an important but unknown piece of the LDC benchmarking story. Benchmarking total cost should be what we are moving towards.

Figure 2: Capital Additions and OM&A per Customer – Typical New Suburban and Older Urban LDCs

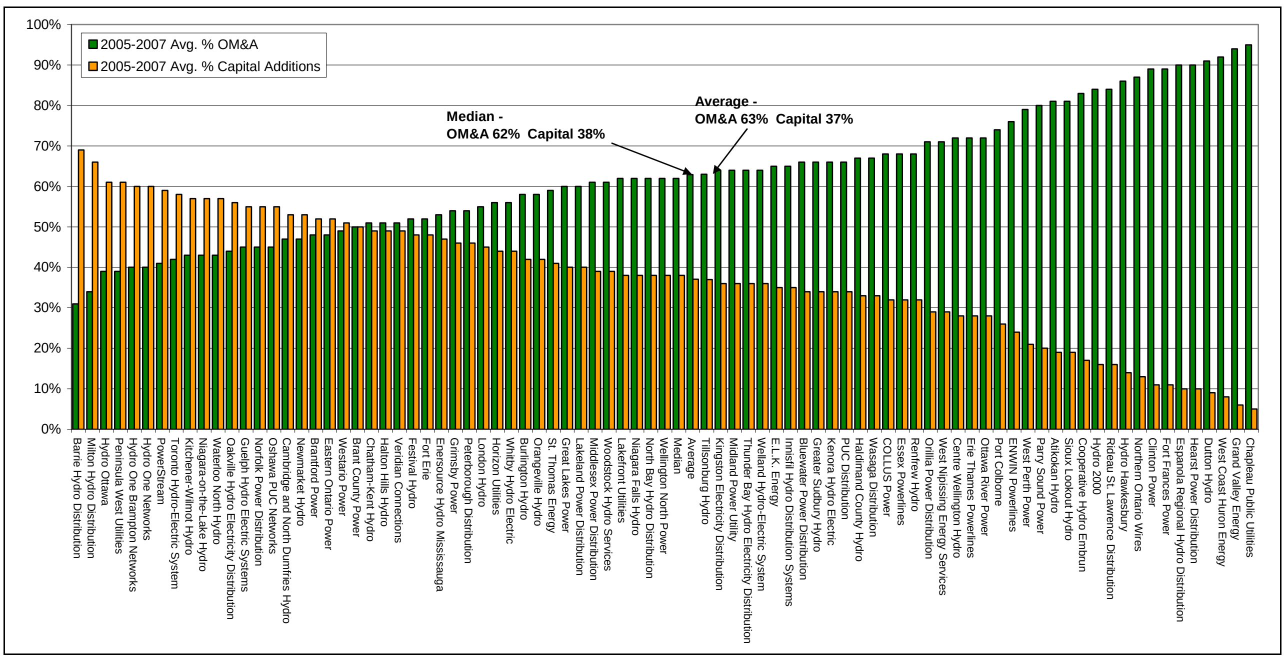


Source: OEB, Reporting and Record-keeping Requirements (RRR), 2005-2007.

While only one illustration of the possible relationships of capital and OM&A, the total spend in percentages of "capital additions" (an OEB published metric) and OM&A are depicted in Figure 3 for all LDCs. There are a number of phenomena evident:

- Approximately 25% of LDCs spend more on "capital additions" than OM&A, but these include both high-growth LDCs and LDCs with low growth and high replacement
- Median and average vary only one percentage, with the median being 62% OM&A and 38% capital, suggesting an even distribution of results
- Approximately 75% of LDCs spending more on OM&A than capital suggests that asset life is longer than depreciation schedules, which is not unexpected, and
- Approximately 25% of LDCs spending more than 70% on OM&A may be an indication of insufficient spending on capital replacement or rebuilding.

Figure 3: Capital and OM&A per Customer Percentage of Total Spend



Source: OEB, RRR, 2005-2007. NB: "Capital Additions" are a metric published in RRR and Yearbook of Distributors.

While the conclusions to be drawn from these findings are yet to be fully determined, they nonetheless suggest that some LDCs are positioned to perform better in a benchmarking framework that only considers OM&A rather than capital and OM&A or total cost.

In summary, we do not presume to have all the answers for the incorporation of capital into the existing benchmarking framework, but we do believe that the benchmarking framework will be improved if it addresses all costs, capital and OM&A. While this may be a challenge in the short term, our view is that the work needs to commence immediately so that a meaningful mechanism for incorporating capital cost will be available as soon as possible.

Peer Grouping Issues: Rationale for Recommendations

Introduction:

We accept there is a legitimate role for peer grouping for IRM purposes, but believe the criteria for establishing the peer groups and the specific assignment of peer characteristics to certain LDCs have methodological implications for the benchmarking that require further consideration and deliberation.

Our recommendations in this regard seek to improve the framework by overcoming unintended distortions that, in our view, create artificial ‘bonusing’ of certain LDCs to the detriment of the integrity of the benchmarking framework. We are pleased that the Board, in initiating this consultation, also seeks to “improve the grouping approach and further reduce the potential for misclassification” in the existing framework.

In the three peer grouping recommendations that follow, our focus is on how the peer grouping could be revised to improve the robustness of the result and provide a more natural reflection of the differences among LDCs and a fairer distribution of superior performers.

Recommendation 4: Abandon Scale as a Peer Group Criterion

> ***“Abandon peer grouping based on scale, recognizing that scale is choice of LDC shareholders and creating scale peer groups is a vehicle for protecting inefficient scale of LDC administration costs.”***

This recommendation is being offered to address what, in our view, are a number of significant weaknesses to the current peer group categorizations, including:

- 12 peer groups for 83 LDCs are too many for the peer groups to be meaningful
- Peer group cohorts have too few members in many cases to be meaningful sample sizes and mergers of LDCs will only make this more evident
- Small LDCs have a greater variability of OM&A costs, allowing the mathematics in the conversion of peer group results to distort the unit cost rankings
- Benchmarking of rural LDCs with urban LDCs inflates group averages and creates a disproportionate number of superior performers from these groups

These issues are worthy of consideration because the competition as to whether a utility is a superior performer in the Unit Cost ranking is driven by competition within a peer group. Within a poorly performing peer group with a wide range of results, the best performing utility of that group can become a superior performing utility across all LDCs by virtue of being the best of a weak group. This is because the OM&A efficiency metric for each LDC is divided into the average of the peer group, with the result determining the LDC's ranking in the unit cost rankings.

4.1 Too Many Peer Groups:

In the present arrangements, as shown in Table 2, there are 12 distinct peer groups for 83 LDCs, based on three ranges of size, six ranges of undergrounding and the binary variable of north and south. When LDCs are specifically assigned, there are three groups with just four members, two groups with five members and only three with more than 10 and no group with more than 15. In addition, Hydro One is in its own group.

The danger of having too few members in a peer group is that the statistical validity for the group is less than in larger groups and the potential for statistical error is greater. This will become more evident through the discussion on this and the next recommendation.

Table 2: LDC Peer Groups and Peer Group Criteria

Scale	Location	Degree of Undergrounding	LDCs
Small	Northern	Low Undergrounding (0-10%)	9(1)
Small	Northern	Medium Undergrounding (10-20%)	4(1)
Small	Southern	Low & Medium Undergrounding (0-20%)	1(2)
Small	Southern	Medium-High Undergrounding (20-50%)	6(3)
Small	Southern	Medium-High Ung. with Rapid Growth (20-50%)	5
Mid-size	Southern	Low & Medium Undergrounding (10-20%)	6
Mid-size	Southern	Medium-High Undergrounding (20-50%)	15
Mid-size	GTA [Southern]	Medium-High Undergrounding (20-50%)	13(4)
Mid-size	Northern	N/A	4
Large	Southern	Medium-High Undergrounding (20-50%)	4
Large	Southern	High Undergrounding (>50%)	5
Large	Northern	N/A [Hydro One Networks]	1

Source: * PEG Report, "Sensitivity Analysis on Efficiency Ranking and Cohorts for the 2009 Rate Year: Update", Table 1, December 3, 2008. (Hereafter, "PEG 'Update' Report"). NB: Numbers and descriptors based on groupings in PEG "Update" Report, which is the most recently published data.

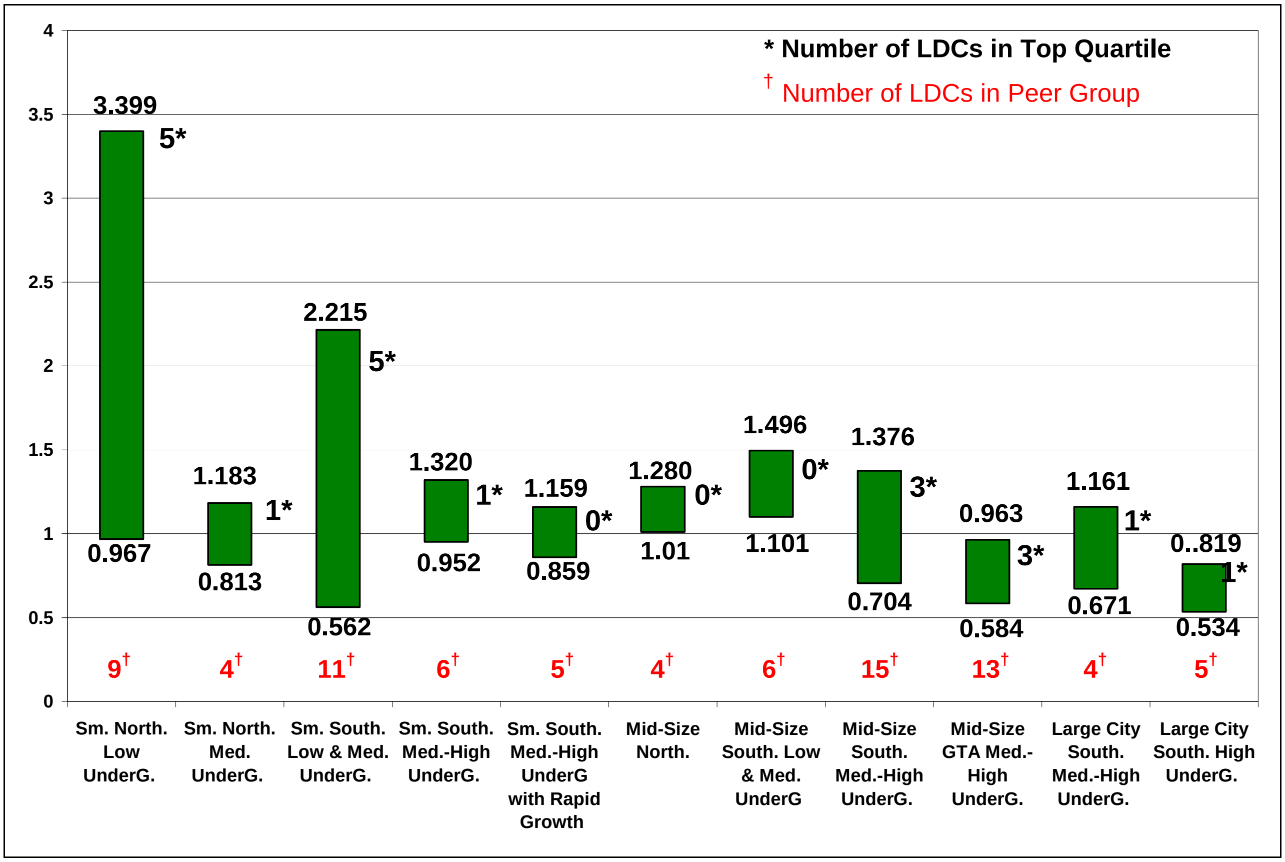
Notes: [1] One LDC has been included in small, but should have been in mid-size based on its number of customers. [2] Three of the LDCs in this group were sold or merged with others in 2007 and 2008, but are still in the 2007 data. [3] Two of these were sold or merged in 2008, but are still in the 2007 data. [4] This group includes Kitchener-Wilmot Hydro, which now qualifies as large with more than 82,000 customers.

4.2 Scale and Peer Grouping:

The use of scale in determining peer groups is not benign because it can have the unintended effect of protecting and enhancing inefficient scale of operation. This is the case because the 83 LDCs in Ontario have been organized into scale-related peer groups and then subdivided further by many undergrounding/overhead categories and by the binary variable of the Canadian Shield physiography. While the latter two create groups based substantially on operating challenges and characteristics that have more limited opportunities for increased efficiency, the same is not true for scale of operation.

With these criteria for the peer groups, there are disproportionate opportunities for small LDCs to be the superior performers on the Unit Cost rankings. This is because, as see in Figure 4, there are five categories for "small" LDCs (less than 10,000 customers), four categories for mid-size LDCs (10,000 to 82,000 customers), and three categories for large LDCs (more than 82,000), although one is for Hydro One exclusively.[17] Small LDCs actually generate 60% of the superior performers (12 of 20).

Figure 4: Range of Unit Cost Metrics by Peer Groups and Unit Cost Superior Performers



Source: PEG, "Update" Report, December 3, 2008, Tables 2 and 11.

The greater variability of OM&A in small LDCs also creates opportunities since there is a wider range of metrics within the small peer groups (as evident in Figure 4). As a result, the mathematics of dividing the individual metric into the group's average will generate a greater number of superior performers. For instance, the "small northern low undergrounding" peer group has a metric range of 2.432 and the "mid-size northern" has a range of 0.27.

[17] Notably, the median size of the 82 LDCs (excluding Hydro One Networks) is just 14,000 customers, meaning there opportunities for relatively small LDCs to be top performers in 9 of 11 peer group categories.

With such a difference in the spread of the metrics, the “small northern low undergrounding” peer group is able to generate five of the 20 top quartile performers, whereas the mid-size northern does not generate any. In the former case, the best performing LDC has a metric of 0.967, and the group average is 1.657, which generates a Unit Cost ranking of 0.584. In the mid-size, the best performer is 1.01 and the group average is 1.018, making the best result 0.798. As a function of the mathematics, this small LDC is better in the Unit Cost ranking than any LDC in the “large city southern high undergrounding” peer group even though every one of these larger LDCs has a lower initial metric than the small LDC.

A similar story of distortion is evident in the “small southern low and medium undergrounding”, where not only five of the 20 superior performers are found, but also the top performing LDC in Ontario as well. With such a wide range of results for small LDCs, peer grouping on scale makes it all but impossible for larger LDCs to be top performers simply because of the mathematics.

4.3 Categorization of Great Lakes Power and Ottawa River Power as “Small”:

The phenomenon of the mathematics of the poorly performing group driving the top quartile performers is not helped by the placement of Great Lakes Power. It has more than 10,000 customers, but it has been placed in the “small northern” rather than the “mid-size northern” grouping where the established criteria would otherwise place it.[18] Moreover, GLP has the lowest line density of any LDC in Ontario and also operates on the Canadian Shield when the rest of the peer group are mostly compact “northern” urban LDCs. It is therefore not surprising that GLP is inflating the group average and driving the largest number of superior performers of any group.

If GLP were placed in the mid-size northern group, where the four LDCs are all in a tight metric range just above 1.0, all four – Greater Sudbury Hydro, North Bay Hydro, PUC Distribution (Sault Ste. Marie) and Thunder Bay Hydro – would have been superior performers instead of middling performers. However, this would be just as inappropriate as the current proposal. This is illustrative of the problems of peer group cohorts being skewed by low density LDC outliers. While GLP could be in its own cohort like Hydro One, these LDCs would continue to be disadvantaged because they cannot receive the lowest stretch factor.

Ottawa River Power (ORP) is also an LDC with more than 10,000 customers, but in its case was placed in small northern medium undergrounding group. Moreover, its service territory arguably does not meet PEG’s criteria for northern, because the majority of it is agricultural rather than on the Canadian Shield, and thus should not be in a northern peer group. Interestingly, this group only has 4 LDCs, which would mean the removal of ORP would leave just three LDCs in the cohort, arguably too few to be a group.

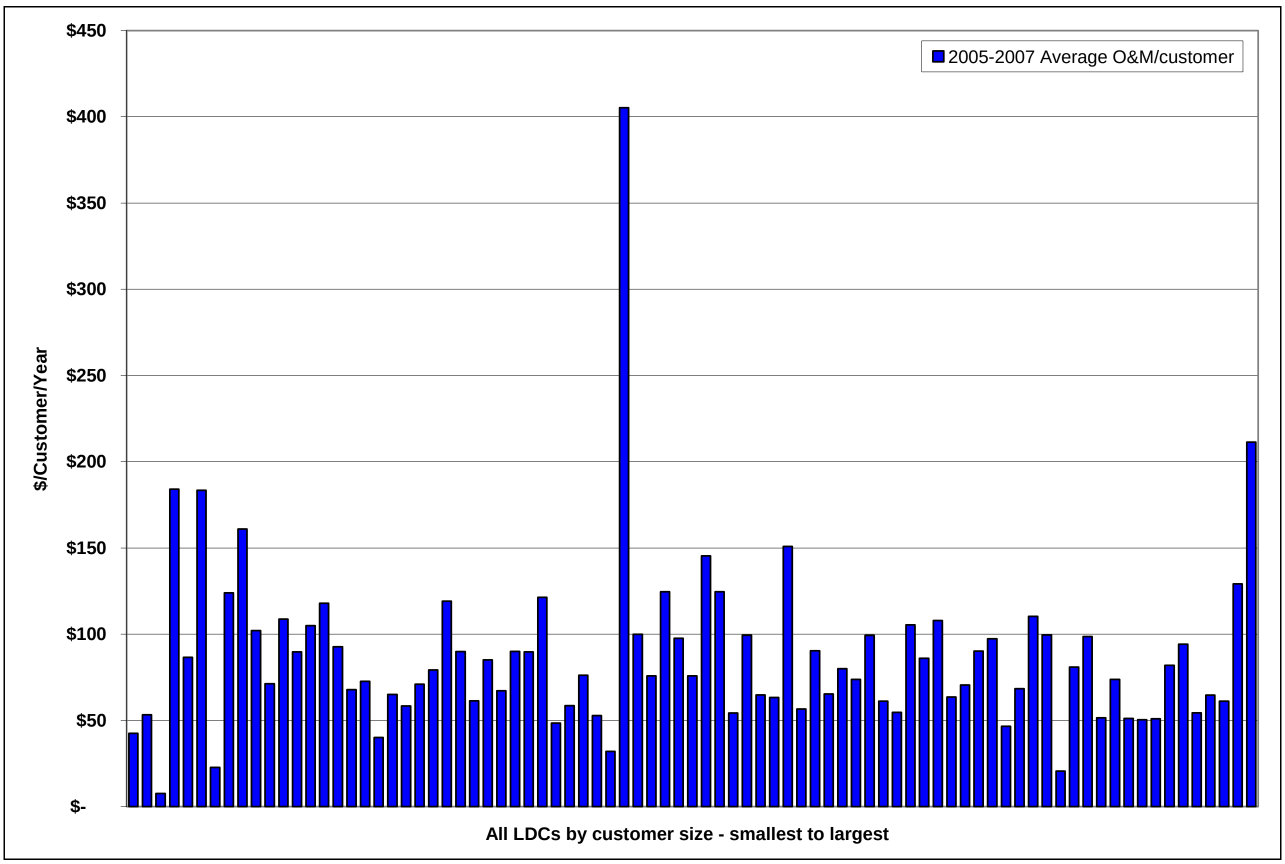
[18] See footnote 2 to Table 1 of the PEG Report, December 3, 2008, where all that is stated is: “Small is defined as less than 10,000 customers with the exception of Great Lakes Power and Ottawa River Power, who have more than 10,000 customers but are defined as ‘small’."

4.4 Scale Peer Grouping Protects Inefficient Scale of Administration:

In making scale one of the most significant variables for peer groupings, the effect is to place less emphasis on administration efficiency drivers in small LDCs. The above examples illustrate that the mathematics in scale-based peer groups makes small LDCs appear to be more efficient than LDCs in the "large" groups. The performance index rewards, then, serves to isolate small LDCs from greater efficiency drivers.

The potential for increased efficiency among all LDCs becomes clear when the controllable cost data for all LDCs is examined. Figures 5 and 6 show, respectively, each LDC's average total O&M and Administration over 2005-2007 in a sequence from smallest to largest LDC. While the challenges of small scale may be thought to be relevant to all OM&A, this is not actually borne out by the data.

Figure 5: LDC O&M Costs per Customer per Year (2005-2007)



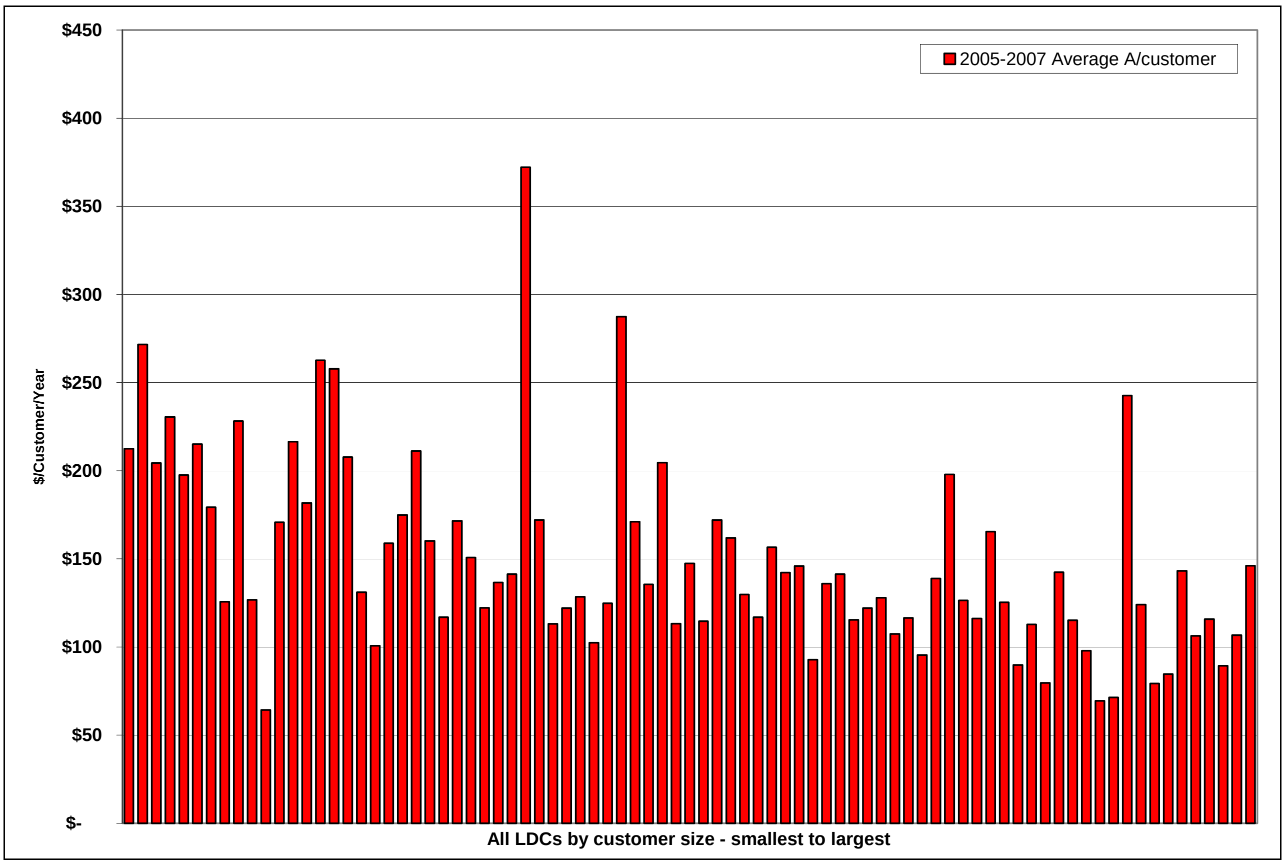
Source: OEB, Reporting and Record-keeping Requirements (RRR), 2005-2007.

When O&M is isolated from Administration, as displayed in Figure 5, the results demonstrate that there are strong performers across the entire range of LDCs from small to large. Indeed, O&M is largely flat at $87 per customer per year. While there are some very high cost exceptions, these are largely explained by the LDC being a low density rural distributor. Indeed, across small (less than 10,000 customers), mid-size

(10,000 to 82,000) and large LDCs (greater than 82,000 customers), there are rural LDCs that would impact the group averages. As a result, O&M is not generally a significant challenge for small scale that needs special peer group treatment.

The situation is different for Administration, as shown in Figure 6. Again, this is a sequence of LDCs from smallest to largest. What the data in the graph indicates is that, while there are strong performers across the entire range of LDCs, the costs are not largely flat as they are for O&M. Rather, many large LDCs have Administration costs under $100 per customer per year, many mid-size LDCs are between are $100 and $150 per customer and many small LDCs are above $150 per customer, although the variability of costs is actually greatest for small scale LDCs.

Figure 6: LDC Administration Costs per Customer per Year (2005-2007)



Source: OEB, Reporting and Record-keeping Requirements (RRR), 2005-2007.

By peer grouping LDCs on scale and using total OM&A to develop the Unit Cost rankings, our view is that small LDCs are given relief from pressures to reduce their high unit costs, particularly on administration. While the cost savings on O&M would be limited, small LDCs do have opportunities to find increased efficiencies on administration costs, such as from contracting out billing and collection to other LDCs or third parties. The higher cost of small LDCs is not generally a result of the O&M costs.

4.5 Purpose of Benchmarking on Scale is Unclear:

While we can accept the notion of peer grouping based on operating characteristics, such as the operating challenges of the Canadian Shield and line density of customers, we are perplexed by the decision to use scale as a peer group criterion. In Ontario, scale has been a shareholder choice rather than a legislative constraint since the passage of the *Energy Competition Act, 1998*.[19] In the previous framework, scale was a constraint and a cost of service regulatory structure was all that could be appropriate because there were no options for scale efficiencies.

The change of the statutory framework to the (Ontario) *Business Corporations Act* has meant that LDCs have been free to merge and sell since 1998, and many have done so precisely to become more efficient. Moreover, they have done so knowing that performance-based regulation or an incentive rate mechanism would replace cost of service regulation and, therefore, they would not be serving their interests by having inefficient scale.

In addition to scale no longer being a constraint, using scale in benchmarking appears to run counter to the advice on LDC consolidation requested and received by government. While the government has not mandated consolidation, the theme that the industry would benefit from it has run through the Macdonald Committee (1996), the White Paper (1997), the *Electricity Act* (1998), Ministry of Energy's paper "Transmission and Distribution: A Look Ahead" (2004) and the Arnett Panel (2007). Moreover, the government has encouraged consolidation through Cabinet approval for the Transfer Tax exemption on public sector mergers and sales on four occasions.

4.6 Summary Comments:

In our view, the benchmarking initiative's use of scale-based peer groups can only be loosely connected to the "underlying principles" adopted for 3rd Generation IRM[20] and does not appear to have a clear foundation in the OEB's general objectives.[21] We are not aware of any specific benchmarking benefit for the sector as a whole from benchmarking on scale.

We are of the view that benchmarking total OM&A is appropriate if there is not benchmarking on scale. In such a framework, the benchmarking will lead LDCs with inefficient administration costs to reduce their back office costs, whether by internal efficiencies, outsourcing or merging with other LDCs to attain scale economies.

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[19] Under the *Power Corporation Act* and *Public Utilities Act*, municipal electric utilities (MEUs) had no options to merge (except in a municipal amalgamation) or sell to other municipal utilities. And while there were a few municipal franchise utilities (e.g., in Cornwall, Gananoque and Fort Erie), an MEU could not convert to a franchise if it already received power from Ontario Hydro.

[20] Board Staff have issued two documents outlining "underlying principles", which are listed here in Appendix 2. See OEB, 3rd Generation Incentive Regulation for Electricity Distributors: Staff Scoping Paper (EB-2007-0673 August 2, 2007), pp. 2-4 http://www.oeb.gov.on.ca/documents/cases/EB-2007-0673/scoping_paper_20070802.pdf ; and see "Underlying principles for development of 3rd Generation IRM," slide 9 Board Staff presentation Proposed Approach & Work Plan to the October 26, 2007, IRM working group meeting. http://www.oeb.gov.on.ca/documents/cases/EB-2007-0673_filings/workinggroup/meeting_20071026/6_3rd_Generation_IRM_20071026.pdf

[21] *Ontario Energy Board Act*, S.O. 1998, CHAPTER 15, Schedule b, s. 1.

In our view, the Board's benchmarking should not use scale as a peer grouping criterion because of the unintended outcome of providing small LDCs relief from efficiency drivers in the incentive rate mechanism.

Recommendation 5: Abandon Undergrounding as a Peer Group Criterion

> ***"Abandon peer grouping based on degree of undergrounding and geography except for Canadian Shield, recognizing these are not significant differentiators of LDC performance in the existing peer groups when measured on O&M costs, given that current reliance on OM&A includes 'administration' costs that do not relate to costs of undergrounding or geography."***

This recommendation is being offered to address what are, in our view, a number of weaknesses in the current peer group categorizations, including:

- Undergrounding costs do not vary significantly across peer groups based on O&M, and outlier groups can be explained by the line density of rural distributors
- Six categories of undergrounding are too many to be meaningful and the overlap of categories across peer groups has potential distortions and unfair results
- Undergrounding costs vary widely and naturally between new suburban and old urban LDCs within the same peer group
- Undergrounding is not a good proxy for the low line density of rural distributors
- 6 of the 13 LDCs in the GTA category are not in the GTA

If we accept that, with the passage of the *Energy Competition Act, 1998*, scale is a shareholder choice and not an appropriate variable for peer group benchmarking, the question then becomes whether the degree of undergrounding and the binary variable of Canadian Shield geography should be kept or should other, more meaningful, differentiators be adopted. This recommendation seeks to demonstrate why classifying on undergrounding is not desirable, while maintaining that Canadian Shield is worth continuing.

5.1 Undergrounding and Canadian Shield Drive O&M, not Administration Costs:

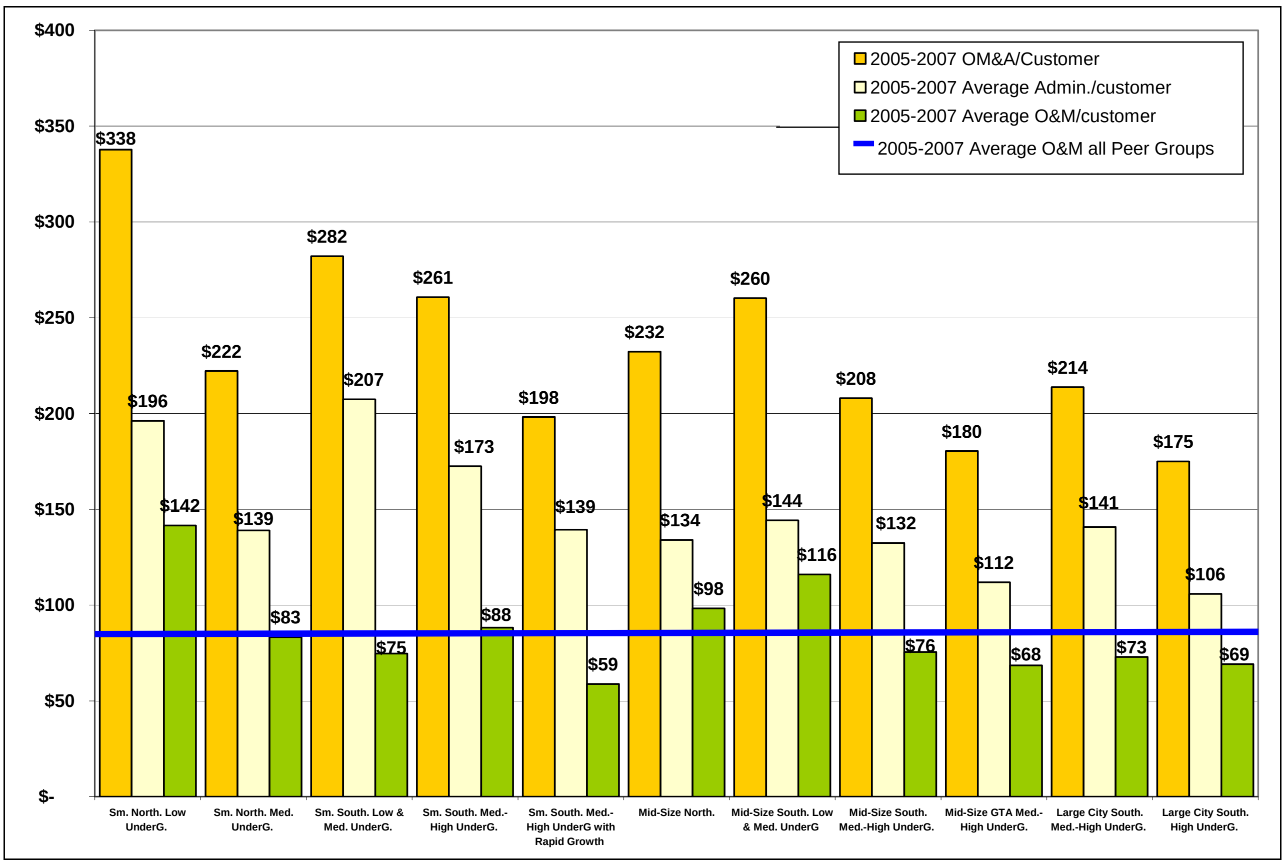
The two variables of undergrounding and Canadian Shield relate to operating challenges, and thus to O&M costs as distinct from administration costs. While the current peer groups do vary on total OM&A, this appears to be more a result of the higher costs of administration in the small LDC peer groups rather than differences in O&M.

Figure 7 presents the OM&A, Administration and O&M data side by side by peer groups to illustrate the point.

An interesting dimension of Figure 7 is how, on the basis of OM&A, the peer groups look quite different, but, on the basis of O&M, the groups are within a close range of costs per customer with a couple of outliers. The inescapable conclusion is that administration is the larger driver of the cost differences among peer groups, but administration has little to do with undergrounding or being on the Canadian Shield.

In Figure 7, the three-year average cost of O&M across the 83 LDCs is $87 per customer per year. What is notable, then, is that eight of the 11 peer groups (Hydro One is on its own as the 12th) have average O&M costs per customer that are within close range of the LDC average. The others, moreover, can be explained quite easily by group characteristics that have nothing to do with undergrounding or the Canadian Shield. The following three observations are made from Figure 7.

Figure 7: OM&A, Administration, and O&M by Existing Peer Groups



Source: OEB, RRR, 2005-2007, and, for the group members, PEG “Update” Report, December 3, 2008, Table 1.

5.1.1 – “Small Northern Low Undergrounding”: The O&M average of $142 for the group suggests that all small northern LDCs have much higher costs. However, the average is being inflated by the presence of Great Lakes Power in the group, whose own O&M costs per customer are $405. This is a result of GLP being a rural distributor, without even the urban centre of others in the group. Although line density is not an O&M driver that is benchmarked, GLP actually has the fewest customers per kilometre of any LDC, lower even than Hydro One. It stands to reason, then, that the group's average costs are higher and, indeed, the group average without GLP is actually $112, which is much closer to the industry norm for O&M.

It is also the case that this group includes four LDCs that include significant annexation of rural territory from Ontario Hydro, making them also low density distributors. As seen in Table 3, these are Atikokan Hydro, Espanola Regional, Northern Ontario Wires, and Sioux Lookout Hydro. If these four and GLP are removed from the O&M group average, the average for "small northern low undergrounding" becomes just $98.

Table 3: Average O&M in Small Northern Low Undergrounding Peer Group

Small Northern Low Undergrounding	**Original Peer Group**	**Without GLP**	**Without all Low Line Density LDCs**
Atikokan Hydro	$183	$183	-
Chapleau Public Utilities	$184	$184	$184
Espanola Regional Hydro Dist.	$109	$109	-
Fort Frances Power	$68	$68	$68
Great Lakes Power	$405	-	-
Northern Ontario Wires	$71	$71	-
Parry Sound Power	$90	$90	$90
Renfrew Hydro	$73	$73	$73
Sioux Lookout Hydro	$161	$161	-
Terrace Bay Superior Wires	N/A	-	-
West Nipissing Energy Services	$71	$71	$71
Peer Group Average	**$142**	**$112**	**$98**

Sources: OEB, RRR, 2005-2007, and, for grouping, PEG "Update" Report, December 3, 2008, Table 1.

What is also notable is that the "mid-size northern" group, which is also at $98 per customer, is within an $11 range above the average, which is what one would intuitively expect because of higher costs on the Canadian Shield. Indeed, when GLP and the other low density LDCs are taken out of the small northern, the O&M for all the northern "urban" LDCs is the same despite the differences in degree of undergrounding.

5.1.2 – "Mid-Size Southern Low and Medium Undergrounding": Similarly, this group at $116 of O&M per customer, is well above the $87 average, but there is a simple explanation. Of the six LDCs in this group, five are LDCs that annexed large rural service territories from Ontario Hydro in relation to a relatively small base of urban customers. The natural consequence of their low line density is that their O&M costs are higher than for urban LDCs. Again, low density is a significant O&M cost driver that is not recognized. Moreover, the best performer in the group, Orillia Power, is the lone urban LDC, which gives it an unfair advantage over all the other "peers" in the group.

5.1.3 – “Small Southern Medium-High Undergrounding with Rapid Growth”: This group stands out because at $59 per customer it is well below average in comparison to the other groups. The issue here, however, is that there are only five LDCs in the group and there is one outlier at just $23 per customer. When the group average is calculated without the outlier, it becomes $68, which is at the same dollar level as the large city peer groups.

Also of note here is that two of the five group members, Grimsby Power and Niagara-on-the-Lake Hydro, may have met the “rapid growth” threshold for reasons that were short-lived. In both cases, the provincial government’s “greenbelt” law now constrains growth in these communities, which are part of the tender fruit portion of the greenbelt.

5.2 Mid-size Medium High Undergrounding Non-GTA and GTA:

Another anomaly to the groupings is the existence of two groups for “mid-size medium high undergrounding”, with one specific to the GTA (Greater Toronto Area). The issue here is that only seven of the 13 LDCs in the GTA specific group are actually in the GTA. Since the GTA is the provincial planning area for Toronto and the four regional municipalities of Halton, Peel, York and Durham, none of Barrie Hydro, Brantford Power, Cambridge and North Dumfries Hydro, Guelph Hydro, Kitchener-Wilmot Hydro and Waterloo North Hydro should be in the GTA group. Moreover, Kitchener-Wilmot Hydro, having exceeded 82,000 customers in 2007, now qualifies as a “large” LDC.

If the category was meant to include the new provincial planning area of the “Greater Golden Horseshoe”, the other six would be included, but such a “GGH” peer group would have significant overlap with the non-GTA peer group, particularly in Niagara, but also in Peterborough.

As evident in Figure 7, the O&M per customer for the non-GTA LDCs is $76 and $68 for the GTA LDCs. However, the O&M for all of the non-GTA LDCs, when this includes the ones incorrectly placed in the GTA, is $74. Also, the O&M for all “mid-size medium high undergrounding” is $72. Since all of these O&M costs are in such close range, it would be helpful if the rationale for the GTA group and the assumptions for inclusion of LDCs from outside the GTA in the group could be explained.

5.3 Comparing Urban and Suburban LDCs in Undergrounding Groupings:

This is an issue that is particularly notable in the two peer groups for “large” southern cities, but would also be evident in the other scale groupings. The differentiator here is “medium-high” undergrounding versus “high” undergrounding. The average O&M in the high group is $69 and in the medium-high is $73. Given that there are only 4 LDCs in the first and five in the second, this is not a significant difference and may be explained by other factors.

What is striking here are two issues visible in Table 4. First, the large, older “urban” LDCs with concentrated downtowns and high line densities are split between the two undergrounding groups, with Horizon (Hamilton and St. Catharines) and London for example in “high” undergrounding and Toronto Hydro and Enwin (Windsor) in “medium high”. And, second, while the differences between older urban and newer suburban LDCs are significant, the framework mixes suburban and urban within groups with, for example, the LDCs Hydro One Brampton, Enersource (Mississauga), PowerStream (Markham, Vaughan, Richmond Hill, Aurora) in “high” undergrounding. This brings into question the value of comparing undergrounding without other considerations.

Table 4: Comparison of Large City LDCs on Undergrounding and Density

LDC	Under-grounding	%	O&M / Customer	Line Density Cust. / km	Growth / Output Index
ENWIN Powerlines	Med.-High	38.5%	$51	74.81	1,332
Hydro Ottawa	Med.-High	36.7%	$61	50.01	2,653
Toronto Hydro	Med.-High	45.5%	$129	69.24	457
Veridian Connections	Med.-High	31.9%	$50	52.87	2,837
Enersource Hydro	High	65.5%	$94	35.47	2,511
Horizon Utilities	High	53.3%	$54	69.55	1,302
Hydro One Brampton	High	69.8%	$51	46.64	5,800
London Hydro	High	51.0%	$82	54.47	2,265
PowerStream	High	69.0%	$65	38.10	4,617

Source: OEB, RRR, 2005-2007, and, for grouping and growth index, PEG “Update” Report, December 3, 2008, Table 1.

Another problematic issue is that both groups mix rapid and low growth LDCs in the same group, such as Toronto Hydro with a growth index of 457 versus Veridian at 2,837 and Hydro One Brampton 5,800 versus Horizon Utilities at 1,302. This is a problem in many groups, but only gets separate treatment for small LDCs.[22]

The issue illustrated here is that degree of undergrounding alone is not a strong explanatory variable of the cost differences between these nine “cities” in a single group let alone two groups. Rather than re-examine the group compositions, it might actually make sense to abandon undergrounding altogether and find a basis for peer grouping the old urban and new suburban LDCs separately. Density would appear to be an appropriate differentiating measure for comparing all LDCs, not just low density rural distributors.

5.4 Overlap of Undergrounding Categories:

The superior performer results also appear to be affected by the overlap of peer categories by the different treatment of undergrounding in the scale categories. The reason for the separation of the groups is also weakened when the costs are compared on O&M, rather than OM&A, which more accurately reflects the undergrounding costs.

[22] Hydro One Brampton and PowerStream have a higher growth index than 4 of the 5 LDCs in the small “rapid growth” group.

For example, there is one southern category for “low and medium” undergrounding (0-20%) with 11 LDCs, which generates 5 top quartile performers. In the north, there are two categories for the same range where the “low” undergrounding (0-10%) has 9 LDCs and generates 5 top quartile performers and the “medium” undergrounding (10-20%) has 4 LDCs and generates 1 top quartile performer. If the two northern undergrounding groups were together, as they are in the south, they would generate only 5 top quartile performers, not 6, with the other one moving to another group.

There are also two southern mid-size medium-high undergrounding groups, where the one for the GTA (as noted above) has many LDCs from outside the GTA. In general, some explanation is required for why the groups need to be separate in some cases but not in others, especially where the cohort size is too small to be meaningful.

5.5 Summary Comments:

The above comments lead us to believe that if the benchmarking and IRM are to be effective, the number of groups needs to be rethought and reduced based on simple and practical measures. This would allow for the peer group size to be increased for more valuable and meaningful group comparisons.

In our view, the 3rd generation IRM will be greatly enhanced by reducing the number of peer groups based on meaningful categories for benchmarking and correspondingly increasing the cohort size for the groups for more valuable comparisons.

Recommendation 6: Adopt Line Density and Cdn. Shield as Peer Group Criteria

> ***“Adopt line density and retain Canadian Shield as the bases for creating meaningful peer groups, potentially establishing the four ‘customers per kilometre’ cohorts of (1) greater than 50, (2) from 25 to 50, (3) less than 25 for rural (southern and northern), and (4) “Shield urban” from 25 to 60, with the reduction of groups from 12 to 4 improving cohort sample size and the new grouping criteria creating a more natural basis for comparing LDC performance given that customers per kilometre appears to be a greater distinguisher of efficiency and provides a more even distribution of superior performers.”***

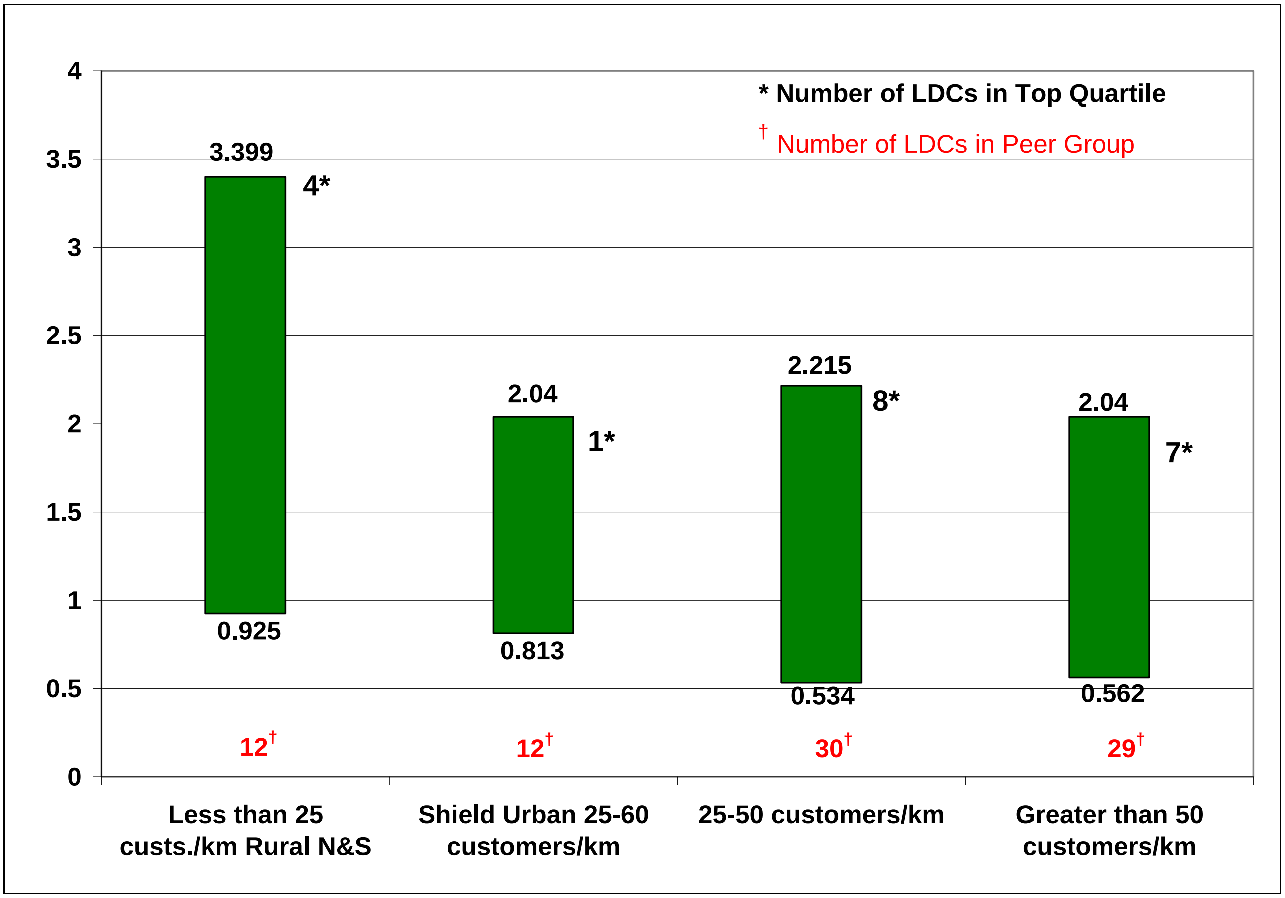
This recommendation is being offered to address the distortions to IRM benchmarking being caused by both the sheer number of peer groups and the ineffectiveness of scale and undergrounding to differentiate LDC performance effectively.

Using line density as the measure to establish peer groups will be of greater assistance to benchmarking because it is a simple and practical metric that every LDC understands to be a significant driver of costs and revenues. Moreover, the measure is easy to calculate and based on existing filed Board data, and thus less prone to error. The metric is the Board's published RRR data filing for "total customers (not including street lighting and sentinel lighting connections)" divided by "total kilometres of line".[23]

The greatest strength of moving to line density is that Ontario needs to peer group both urban and rural LDCs in a manner that ensure fairness. Rural low-density LDCs have different cost drivers than their higher density peers, and undergrounding and scale cannot address this situation. Similarly, urban LDCs are affected by distortions from high cost rural LDCs in peer group averages, as in the case of Great Lakes Power's impact on the "small northern low undergrounding" group.

Figure 8 provides a representation of the four peer groups by their range of metrics, number of LDCs per group and number of superior performers by group.

Figure 8: Peer Groups Based on Line Density and Canadian Shield



Source: PEG "Update" Report, December 3, 2008, Tables 2 and 11. NB: The peer groups have been recast as shown using the breakout data in Table 2 of this PEG Report and assigning the LDCs to the four peer groups represented. The representation does not account for later recommendations in this submission that address LDCs in the "northern" category that are not on the Shield.

[23] The metric is meant to capture "circuit" kilometers of line, where one kilometre of single phase and one kilometre of three phase line in both cases is one kilometre of line. We recommend the Board provide specific direction on how to calculate kilometres of line and that consideration be given to adopting the existing standard and detailed instructions set by the Canadian Electricity Association. This would provide consistent measurement and permit inter-provincial comparisons.

6.1 More Valuable Peer Grouping Metrics with Better Cohort Group Size:

The LDC groupings generated by line density, which are listed in Appendix 3, also have the benefit of the LDCs in the cohorts making common sense, as follows:

Greater than 50 Customers per Kilometre: For an LDC to have greater than 50 customers per kilometre, the LDC must have an older urban area with small lots and apartments whose prevalence has not been diminished by the lower density that comes with suburbs or annexed rural areas diluting the customer line density of the old urban.

LDCs in this group cover a wide range of scale, but since O&M is flat across scale and there are strong performers all along the range of scale (as seen in Figure 5), there is no inherent bias for large LDCs. Indeed, the strongest LDC in the group would likely be Hydro Hawkesbury, which is a superior performer in the scale and undergrounding criteria. There would be 29 LDCs meeting these criteria, which makes for a more robust cohort group than in scale and undergrounding.

From 25 to 50 Customers per Kilometre: For an LDC to have 25 to 50 customers per kilometre, it has to have one of two situations. First, it would be a largely suburban LDC, where the suburbs are more prevalent than the old and compact urban centre that might also be present. Second, it could be a largely urban area that also includes some low density rural areas. There would be 30 LDCs meeting these criteria, which again makes for a more robust cohort group than in scale and undergrounding.

Less than 25 Customers per Kilometre: For an LDC to have less than 25 customers per kilometre, such as those in Table 5, it either began as a rural, low density distributor, such as Hydro One or Great Lakes Power, or became one through an annexation of Ontario Hydro service territory.[24] The advantage of this grouping is that it creates a home for low density distributors, which are disadvantaged in peer groups based on scale and undergrounding because these variables do not reflect the unique challenges of so few customers for so many line kilometres.

The advantages of creating a rural low density group are many:

- Creates a better set of peers for Great Lakes Power
- Puts Hydro One Networks into a peer group and allows it an opportunity it would otherwise not receive to obtain the lowest stretch factor
- Places low density distributors like Haldimand County Hydro in a cohort group that is meaningful to its operation and cost profile.

[24] There is a simple basis for understanding how most LDCs are urban, but some are rural. Early electrification in Ontario occurred mostly by "municipalisation", where urban municipal councils either created a public utility or a municipal franchise, although all the public utilities were required to receive power from Ontario Hydro. Since rural municipalities were largely restricted in creating utilities by the high cost of low density service territories, rural electrification largely fell to Ontario Hydro as a default or residual provider. In the legal framework which preceded the *Energy Competition Act, 1998*, a new or existing municipal electric utility could nevertheless annex territory from Ontario Hydro. Those LDCs that fit the rural low density category generally have a small urban base compared to the total annexed area. Other LDCs do have rural customers, including "large city" peer group LDCs such as Horizon Utilities, Hydro Ottawa, London Hydro, PowerStream and Veridian, but the line density of the urban area is more prevalent.

Table 5: Rural Low-Density LDCs – less than 25 customers per Kilometre

LDC Name	LDC Location	Line Density
Great Lakes Power	North	6.32
Hydro One Networks	North and South	9.76
Haldimand County Hydro	South	12.13
Sioux Lookout Hydro	North	13.05
Peninsula West Utilities	South	13.89
Halton Hills Hydro	South	15.04
Northern Ontario Wires	North	16.52
Eastern Ontario Power	South	18.12
Atikokan Hydro	North	18.60
Innisfil Hydro Distribution Systems	South	22.17
Niagara-on-the-Lake Hydro	South	23.08
Espanola Regional Hydro Distribution	North	24.20

NB: Niagara Falls Hydro and Pen. West Utilities are now Niagara Peninsula Energy and will likely end up in the 25 to 50 category.
Source: OEB, Reporting and Record-keeping Requirements (RRR), 2005-2007.

As is evident in Table 5, there are 12 LDCs with less than 25 customers per kilometre, which is a reasonable sample size and makes for a more robust cohort group than most of the categories in scale and undergrounding framework for peer groups.

Thus, by creating a category for rural LDCs, the high cost of operating a low density distributor no longer is able to distort the peer group average of the previous categories that were only based on scale. With 12 LDCs with less than 25 customers per kilometre, there is a sufficient sample size for the peer group to be meaningful.

Shield Urban: For an LDC to be in this category, it must have the binary character of a majority of its service territory being on the Canadian Shield and have more than 25 customers per kilometre and less than 60. Presently, no LDC actually on the Shield has more than 60, so the range is almost the same as the non-shield category of 25 to 50. There are currently 12 LDCs that are “northern” and urban, which is a reasonable sample size and makes for a more robust cohort group than most of the categories in scale and undergrounding.[25]

6.2 Better Distribution of Superior Performers:

One of the principal benefits of having four line density based peer groups is that it overcomes the chief drawback of the previous 12 groups. With 12, the high degree of cost variability in the small LDCs was driving a disproportionate share of superior performers.

[25] There would be less than 12 if the substance of CEIRM’s Recommendation 7 were also accepted. The criterion of 25 to 60 customers per kilometre anticipates Recommendation 7, in part, because two of the LDCs suggested for exclusion are above 70.

By moving to line density, which brings together large and small LDCs into the same groups, the peer grouping framework receives both more LDCs per group and a wider range of metrics across all groups. As is evident in Figure 8, there is a more even distribution of LDCs by group and superior performers by group.

When the data in Figure 8 is displayed in Table 6, the distribution of results is much more even. Indeed, no group has less than 8% or more than 33% of its members becoming superior performers. This is starkly different from the distribution based on scale and undergrounding, as shown in Table 7, where the distribution range is from 0% in three groups and as high 55% for “small northern low undergrounding”.

Table 6: Distribution of Peer Group Results by Line Density & Canadian Shield

Line Density Group	# LDCs	Superior Performers	%
Less than 25 Customers per Kilometre	12	4	33%
Shield Urban 25 to 60 Customers per Kilometre	12	1	8%
From 25 to 50 Customers per Kilometre	30	8	27%
Greater than 50 Customers per Kilometre	29	7	24%

Source: PEG “Update” Report, December 3, 2008, Table 2. NB: The peer groups have been recast as shown using the breakout data in Table 2 and assigning the LDCs to the four peer groups represented.

Table 7: Distribution of Peer Group Results by Scale and Undergrounding

Scale and Undergrounding Group	# LDCs	Superior Performers	%
Small Northern Low Undergrounding	9	5	55%
Small Northern Medium Undergrounding	4	1	25%
Small Southern Low & Medium Undergrounding	11	5	45%
Small Southern Medium-High Undergrounding	6	1	17%
Small Southern Medium-High Ung. with Rapid Growth	6	0	0%
Mid-Size Northern	4	0	0%
Mid-Size Southern Low & Medium Undergrounding	6	0	0%
Mid-Size Southern Medium-High Undergrounding	15	3	20%
Mid-Size GTA Medium-High Undergrounding	13	3	23%
Large City Southern Medium-High Undergrounding	4	1	25%
Large City Southern High Undergrounding	5	1	20%

Source: PEG “Update” Report, December 3, 2008, Tables 2 and 11.

6.3 Summary Comments:

This recommendation for moving the bases of peer grouping to line density and Canadian Shield is being offered as a way to create more balance in the size of the cohort groups for benchmarking, more meaningful size of cohort groups for methodological rigour and less potential for distortion of results. When peer grouping is based on scale and undergrounding, we believe the inclusion of rural LDCs with urban ones creates unequal distribution of opportunities for LDCs to be superior performers within their peer groups.

Among the urban line density groups, there are LDCs that will nonetheless have large rural service territories, generally as a result of annexations from Ontario Hydro. In these cases, some measure of customers per square kilometre might also be considered if it is determined they are disadvantaged by line density alone.

In our view, the Board's benchmarking rigour for 3rd generation IRM will be greatly enhanced both by moving to just four line density based peer groups because it ensures a more equal distribution of LDCs to the peer group cohorts and a more practical recognition of the operating cost differences between LDCs.

Data Quality Issues: Rationale for Recommendations

Introduction:

Our three data quality recommendations focus on how the collection and use of data can be increased in their rigour to ensure a greater effectiveness from the benchmarking.

These recommendations are a reflection of our commitment to the concept of IRM and its successful implementation. We believe IRM is not without its risks and difficulties, and this is all the more reason in our view to ensure data quality and rigour from the outset. The long-term success and effectiveness of IRM will be better for the effort.

Recommendation 7: Treatment of Canadian Shield

> ***"Restrict the inclusion of LDCs in the northern binary variable for the econometric benchmarking and the unit cost peer grouping to LDCs that are geographically located on the Canadian Shield, which had been the rationale of the consultant, Pacific Economics Group, to ensure that non-Shield LDCs are not artificially and unjustifiably able to become an econometric and unit cost superior performers and to ensure there is no confusion over the purpose of the category."***

This recommendation is being offered as a way to address inequities in the econometric and unit cost benchmarking that result from LDCs that are not on the Canadian Shield receiving the northern benefit through a misapplication of the criteria.

The northern binary variable, according to the PEG, was specifically added to the econometric benchmarking to compensate for the higher costs of operating where a "majority" of an LDC's service territory is on the Canadian Shield. The binary variable also has been use to determine those LDCs in "northern" peer groups.

The benefit is meant to be a compensating variable because, as the report states, "The Shield is a physiographic region characterized by shallow, rocky soils and numerous lakes. Since the land receives considerable precipitation but is unsuited for agriculture, rural areas of the Shield are typically forested. We expect OM&A expenses to be higher on the Shield."[26]

7.1 Econometric Benchmarking and Northern Binary Variable:

We note with interest PEG's sensitivity analysis in the econometric benchmarking with respect to the northern binary variable, where the results are published in the "update" of its sensitivity analysis report as "Table 6".[27] As we understand the exercise, PEG held all variables and data inputs constant from the July 2008 rankings while it removed the northern attribute from Renfrew Hydro to see how the econometric rankings were affected. Table 8 of this submission displays the results.

What one would expect from this exercise, given the justification for the variable, is that Renfrew Hydro would lose the advantage or benefit of the northern binary variable and, all other variables and data inputs being held constant, Renfrew Hydro would not benchmark as well, even if the difference was small.

In the sensitivity analysis released for this consultation, PEG appears to confirm this finding by writing:

> "The new Renfrew data used to re-estimate the econometric model led to small changes in estimated coefficients, and standard errors, which were nevertheless material enough to move these three distributors from one identified cohort into another. The classification for Renfrew itself was not impacted by this sensitivity test; the company was in the top efficiency cohort in the July 2008 update and in our current results, although the difference between its actual and predicted cost widened from -19.3% in July to -24.8% with the new data."[28]

[26] Pacific Economics Group, *Benchmarking the Costs of Ontario Power Distributors,* March 20, 2008, p. 50. http://www.oeb.gov.on.ca/documents/cases/EB-2006-0268/PEG_Final_Benchmarking_Report_20080320.pdf

[27] The PEG report was initially released on November 21, 2008, at the beginning of the current consultation. The "update" report was released on December 3, 2008, after PEG realized it had uses 2004-2006 data for some LDCs and 2005-2007 data for other LDCs. See: http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0673/PEG_Sensitivity_Analysis_20081117.pdf and http://www.oeb.gov.on.ca/OEB/_Documents/EB-2007-0673/PEG_Updates_20081203.pdf , p. 2.

[28] See page 4 of the December 3rd "update" report. The actual and predicted cost difference is different in the November 21st report.

Table 8: Superior Performer Sensitivity to Renfrew Hydro Northern Variable

July Results*			December Results**			Change
LDC	**Metric**	**Rank**	**LDC**	**Metric**	**Rank**	**July/Dec.**
Hydro Hawkesbury	0.643	1	Hydro Hawkesbury	0.644	1	0.001
Chatham-Kent Hydro	0.691	2	Chatham-Kent Hydro	0.694	2	0.003
Northern Ontario Wires	0.711	3	Northern Ontario Wires	0.714	3	0.003
Cambridge and N. Dum.	0.715	4	Cambridge and N. Dum.	0.718	4	0.003
E.L.K. Energy	0.729	5	E.L.K. Energy	0.733	5	0.004
Grimsby Power	0.764	6	**Renfrew Hydro**	**0.752**	**6**	**-0.055**
Oshawa PUC Networks	0.787	7	Grimsby Power	0.769	7	0.005
Lakeland Power	0.789	8	Oshawa PUC Networks	0.781	8	-0.006
Hydro One Brampton	0.793	9	Lakeland Power	0.787	9	-0.002
Kitchener-Wilmot Hydro	0.805	10	Hydro One Brampton	0.792	10	-0.001
Renfrew Hydro	**0.807**	**11**	Kitchener-Wilmot Hydro	0.804	11	-0.001
Barrie Hydro	0.814	12	Barrie Hydro	0.810	12	-0.004
Festival Hydro	0.822	13	Festival Hydro	0.827	13	0.005
Welland Hydro	0.834	14	Welland Hydro	0.839	14	0.005
Hydro 2000	0.840	15	Hydro 2000	0.845	15	0.005
Kingston Electricity	0.860	16	Kingston Electricity	0.868	16	0.008
Horizon Utilities	0.864	17	Horizon Utilities	0.872	17	0.008

* PEG “Update” Report, December 3, 2008, Table 3. ** PEG “Update” Report, ibid., Table 6.

If, however, the actual changes in rankings are examined there is a counter-intuitive result that is more than the small difference PEG suggests. Where no other LDC metric in the superior performer category moves more than plus or minus 0.008, Renfrew Hydro’s metric decreases 0.055 from 0.807 to 0.752. Somewhat surprisingly, as shown in Table 8, this improves Renfrew’s ranking 5 places from 11th to 6th.[29] By rights, Renfrew Hydro should not have benchmarked as well, but ends up benchmarking better.

What is perplexing about the outcome of this sensitivity test is that the northern binary variable appears to be a burden rather than an advantage for northern LDCs. Indeed, while this exercise was only done as a sensitivity test, with Renfrew Hydro left on the Canadian Shield for the econometric and unit cost (peer group) benchmarking, Renfrew Hydro now has self-interest in getting itself out of the “northern” category.

Given the anomaly of this result, Board Staff should clarify whether the northern and other econometric variables are working correctly before Renfrew and other northern

[29] PEG, “Update” Report, December 3, 2008, Tables 3 and 6.

LDCs ask to have the variable removed for them, unless they in fact should not be considered northern in the first place.

7.2 Determination of Canadian Shield LDCs:

While we agree and accept that econometric and unit cost analysis for LDCs should take the operating challenge of the Canadian Shield into consideration, some of the benchmarking assumptions provide us reason for pause.

Although the northern "benefit" variable may very well be too generous, we do not suggest that it be revisited at this time given the limitations of the consultation. The problem we nevertheless believe can and must be addressed is what appears to be a misapplication of the "northern" benefit to some LDCs that are not on the Canadian Shield in the econometric and unit cost analysis.

According to PEG, the creation and recognition of the "northern" variable is required, as noted more fully above, because "The Shield is a physiographic region characterized by shallow, rocky soils and numerous lakes. Since the land receives considerable precipitation but is unsuited for agriculture, rural areas of the Shield are typically forested."[30] No other criteria are provided, such as climatic conditions, for being determined "northern".

Based on research using the PEG criteria and resource material for Canadian Shield, there are four LDCs classified as "northern" whose service territories are not on the Canadian Shield. The four are Renfrew Hydro, Ottawa River Power, Northern Ontario Wires and Hearst Power. Two of the four are superior performers in the econometric rankings and three of the four are superior performers in the unit cost (peer group derived) rankings.

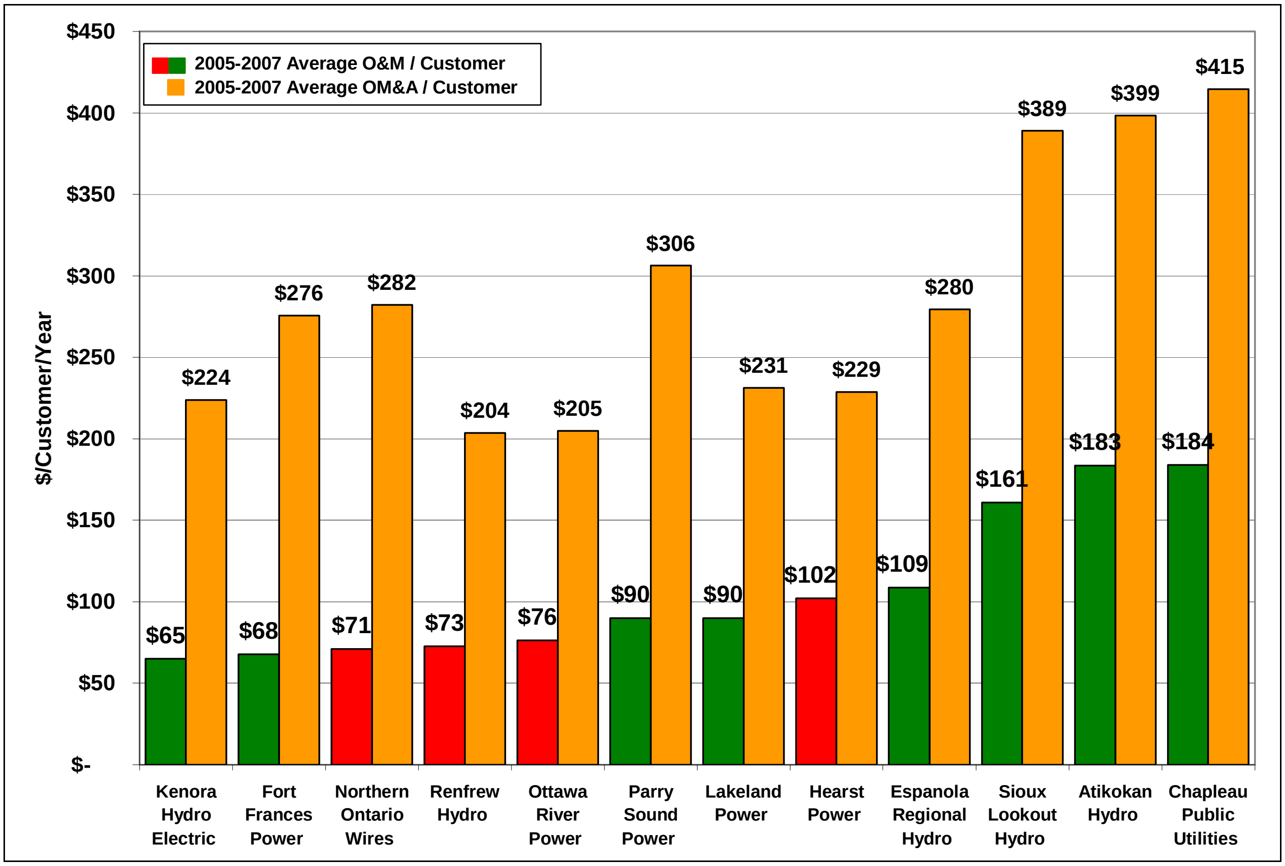
As can be seen in Figure 9, these four LDCs are among the strongest performers among small "northern" LDCs. Based on total OM&A, these four LDCs are, in fact, crowding out other LDCs that are deserving of being given consideration for being on the Shield. Moreover, when the LDCs are compared just on O&M, which is most affected by Shield conditions, and not with Administration included, the LDCs not on the Shield are not even the ones with the lowest costs.

There are a number of data sources and reasons to base the exclusion of these four LDCs from the northern benefit, including the reference material used by PEG.[31]

[30] PEG, "Benchmarking the Costs of Ontario Power Distributors," March 20, 2008, p. 52.

[31] PEG cites L.J. Chapman and D.F., Putnam, *The Physiography of Southern Ontario*, a book which includes a map of the same name, *Physiography of Southern Ontario* (Ontario Geological Survey Map P.2715, 1984). The map is included with this submission as Attachment 2. NB: The book's citation by PEG has an error. While the year of publication is stated as 1996, the third and most recent edition was published in 1984. The first edition was in 1951 and the second edition was in 1966 and reprinted in 1972.

Figure 9: O&M and OM&A of "Small" Northern LDCs



Source: OEB, Reporting and Record-keeping Requirements, 2005-2007. NB: GLP is also considered "small", but is not shown.

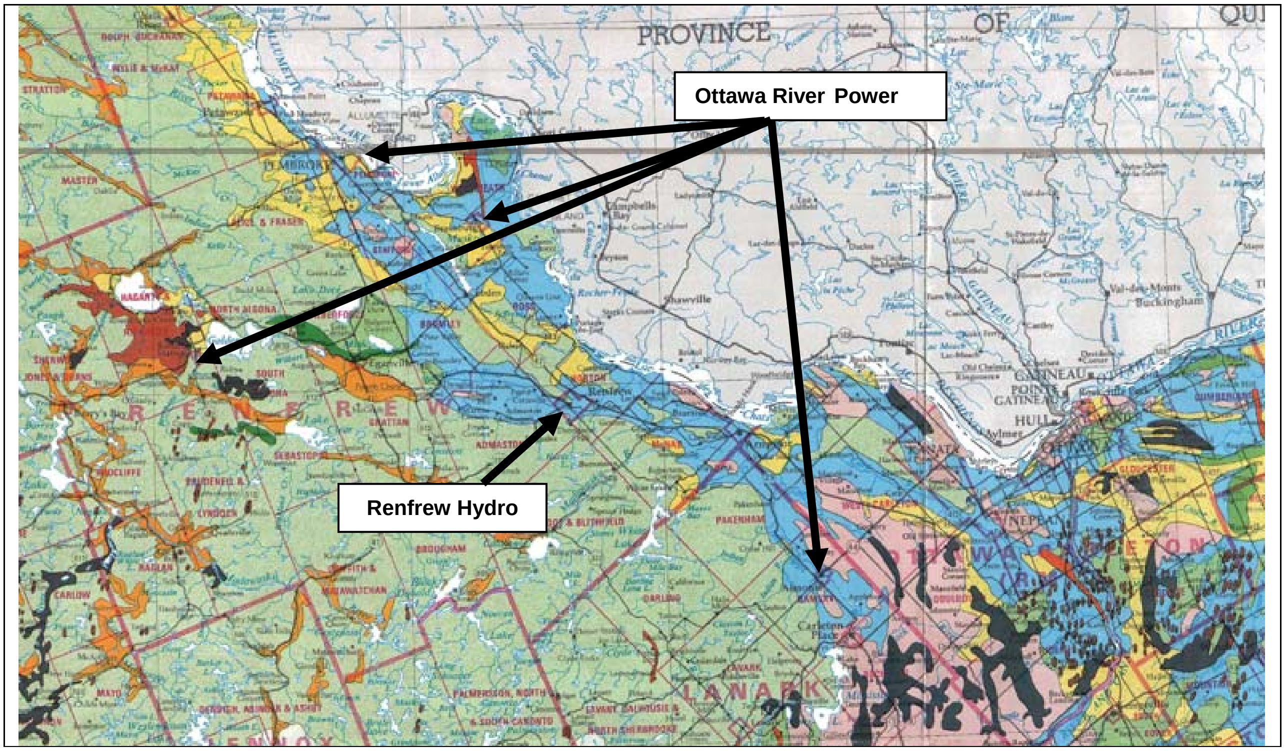
7.3 Renfrew Hydro and Ottawa River Power:

As evident in Figure 10, which is a cut-out from the reference map used by PEG, all of Renfrew Hydro's service territory is actually on "clay plain" rather than shallow rocky soils. This conclusion is confirmed by the aerial photography available on Google Earth, which indicates that the Town of Renfrew is surrounded by farms. (See images in Att. 4). Given that the area supports "agriculture", a key consideration for PEG, this would suggest that Renfrew Hydro has incorrectly been placed in the northern category.

Similarly, Ottawa River Power's (ORP) service territory in Pembroke and Beachburg is on "sand plain" and "clay plain" and its territory in Almonte is on "clay plain". The agricultural character of these communities is also clearly visible from Earth. (See images in Att. 4). Killaloe, its smallest territory, is on "bevelled till plain", "till moraine" and "spillway". While Killaloe is on the Shield, this is not the "majority" of ORP's service territory. Indeed, Killaloe represents only about 300 of its 10,200 customers.[32]

[32] Extrapolated with growth from, Ontario Hydro, Municipal Utility Data Bank (1997).

Figure 10: Excerpt of "The Physiography of Southern Ontario" (1984) for Renfrew Hydro and Ottawa River Power



Source: *Physiography of Southern Ontario* (Ontario Geological Survey Map P. 2715, 1984).
NB: The map key is provided in Attachment 1. For the purposes here, the colour scheme found in the map key indicates: Blue is "Clay Plain"; Yellow is "Sand Plain"; Light Green is "Bevelled till Plain"; Dark Green is "Till Moraine" and Orange is "Spillway".

The danger of making an exception for ORP based on Killaloe is that Veridian, which has 109,000 customers, has about 6,000 in Gravenhurst, and thus a higher percentage of customers on the Shield than does ORP. In neither case are the service territories the "majority" in the PEG requirement.

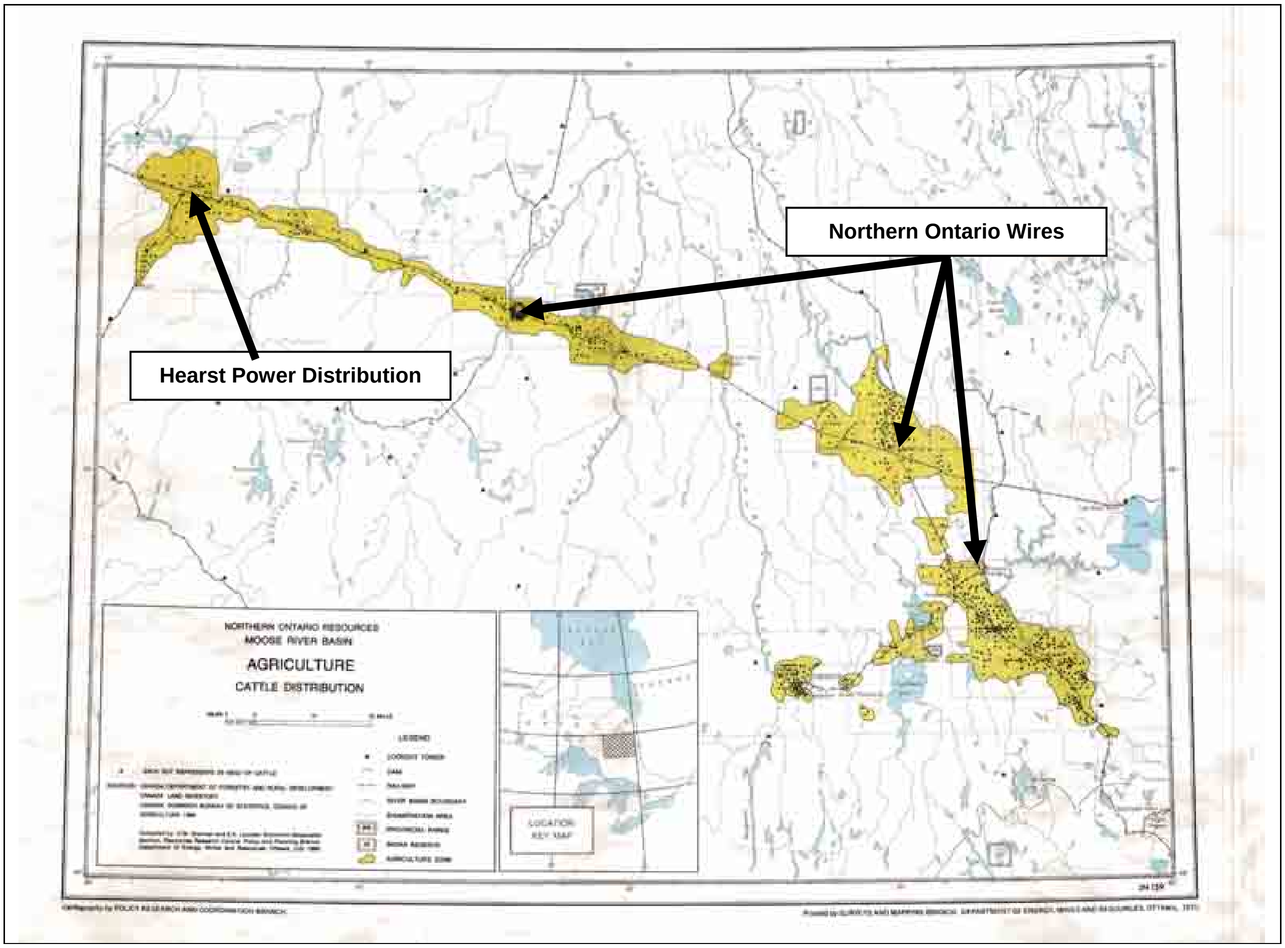
7.4 Northern Ontario Wires and Hearst Power:

In the case of Northern Ontario Wires (NOW) and Hearst Power, PEG's reference map cannot be used because it only covers southern Ontario. Other reliable evidence, however, indicates that none of the communities served by these LDCs – Cochrane, Kapuskasing, Iroquois Falls and Hearst – is on the Canadian Shield.

These communities and their LDCs are instead part of a distinct geographic form known as the "Cochrane Plain" and "Great Clay Belt". The early permanent settlement of the area was based on agriculture and, as indicated in Figure 11 (and Att. 3), the areas continue to sustain agriculture.[33] The "agricultural" character would suggest these LDCs do not meet the PEG criteria for Canadian Shield. (See Google Earth images in Att. 4).

[33] This history of agricultural settlement in this area is well established in such articles as: Jon Kent, "Agriculture in the Clay Belt of Northern Ontario," *Canadian Geographer* 10:2 (1966), and George L. McDermott, "Frontiers of Settlement in the Great Clay Belt, Ontario and Quebec", *Annals of American Association of Geographers* (1961). (See Attachment 5).

Figure 11: Agriculture and Northern Ontario Wires and Hearst Power



Source: Surveys and Mapping Branch, Department of Energy, Mines and Resources, *Agriculture, Cattle Distribution, Northern Ontario Resources, Moose River Basin* (Ottawa, 1972). (See Attachment 3 for the PDF of the map, where the names of the towns are more clearly visible).

The reason for correcting these misapplications of LDCs to the Canadian Shield is that NOW and Renfrew Hydro are both superior performers on the econometric rankings list and these two plus Hearst Power are superior performers on the Unit Cost rankings list. In the result, Renfrew Hydro and NOW receive the best stretch factor.

If, however, all four of these LDCs misapplied to the Shield are put in their proper peer group category, the distribution of superior performers is actually quite different. Indeed, assuming the econometric results do not change, neither of Renfrew Hydro and NOW would be superior performers in another group. The changes are not insignificant.

7.5 Climate and other Non-Canadian Shield Determinants for "Northern":

While a counter argument to the exclusion of Renfrew Hydro, ORP, NOW and Hearst Power from the Canadian Shield binary variable and northern peer groups may be climate, this criterion has never been presented to stakeholders in any reports or been the subject of any public consultation.

To our knowledge, no rigorous analysis of climate issues has been commissioned to determine which LDCs suffer from severe enough climatic conditions to make them deserving of receiving the same binary consideration as LDCs on the Canadian Shield. Therefore, if LDCs are to be given benchmarking considered based on climate, all LDCs should have been invited to make their case. For instance, LDCs like Hydro Ottawa, Hydro 2000, Hawkesbury Hydro and Westario Power could make persuasive arguments to be considered northern on climate conditions as well.

The danger of opening up climate as a condition without a study is that, if Renfrew Hydro and ORP are deserving of the "northern" benefit based on climate, so should a number of other LDCs in the area. Here are the comparative north latitudes:

- Renfrew Hydro (northern beneficiary) – centre of Renfrew is 45º 28'
- Hydro Ottawa – centre of Ottawa is 45º 25'
- Hydro 2000 – centre of Alfred is 45º 33'
- Hawkesbury Hydro – centre of Hawkesbury is 45º 36'
- Ottawa River Power (northern beneficiary) – centre of Pembroke is 45º 49'
- Ottawa River Power (northern beneficiary) – centre of Almonte is 45º 13'.

We acknowledge that NOW and Hearst Power differ because they are much further north than LDCs in the Ottawa Valley, and the difference in winter temperature on equipment and working conditions would not be insignificant. On the surface, however, the climatic conditions in parts of southern Ontario might also have an extraordinary impact on LDC O&M costs. For instance, the LDCs on the Lake Huron coast, such as Westario Power, experience among the most difficult winter storms in Ontario.

7.6 Summary Comments:

In our view, 3rd generation IRM should limit the northern benefit for now to those LDCs with actual Canadian Shield physiographic characteristics, which is the only criterion that has been presented to stakeholders. The integrity of the results of the benchmarking is what is at stake. The reason is that the LDCs in the "northern" peer groups that are not on the Shield quite possibly have cost advantages against LDCs actually on the Shield. The consequence is that it is more difficult for actual Shield LDCs to be superior performers.

Other variables like climate conditions may deserve consideration alongside Canadian Shield for inclusion in "northern" peer groups. However, these variables should only be added after there has been commissioned research that demonstrates the impact of climate or other conditions on operations and stakeholder consultations to provide guidance on the results.

Recommendation 8: Wholesale Customers and LDC Throughput Data

> ***"Ensure the data set measuring energy throughput efficiency for LDCs addresses all the different permutations for throughput not billed by the LDC, including the energy consumed or generated by wholesale market participants 'embedded' in an LDC's system but not transacted through the LDC and the customer-owned 'distributed generation' that fulfils government policy objectives but otherwise displaces throughput, recognizing that all of these variables need to be included for a fair measure of LDC efficiency for there to be a like-for-like comparison of LDCs."***

This recommendation is being offered to address what may amount to a significant penalty imposed on LDCs where the energy generation and consumption of very large customers is not accurately reflected in the benchmarking data. An LDC with embedded wholesale market participants (whether consuming or generating energy) and "behind-the-meter" generation does not bill for the energy used for these customers, but rather just the wires services to connect these customers.

In the cases of embedded wholesale market participants (EWMP), there appears to be potential for legitimate confusion and error in the collection and reporting of throughput data. Part of the problem appears to be that the LDCs, while privy to the consumption data for these customers, do not bill the customers for energy. The other part is that the benchmarked throughput data for these customers appears to be derived by deduction from other numbers provided by LDCs. The numbers used to determine throughput appear to be:

1. Wholesale kWh of the LDC, defined as "the total kWh that flows into the system from either the IESO controlled grid (either directly from the High Voltage transmission system or from host distributors) or embedded generators",
2. Retail kWh, defined as, "the total kWh consumed within service territory", and
3. Distribution system kWh losses.[34]

In this framework, the formula for determining throughput for EWMPs appears to be: EWMP kWh = 1 – (2 + 3). The weakness in this formula, however, is that the IESO, by billing the EWMPs directly, does not include their energy consumption in the "wholesale" bill it charges the LDCs, but the RRR instructions to LDCs do not specify the inclusion of EWMPs that are consumers rather than generators. As a result, an LDC reading the RRR instructions, as written, might not know to include energy in throughput that it does not bill customers for itself.

The consequence of this is that the RRR wholesale and retail kWh numbers used for benchmarking purposes may not reflect all kWh throughputs. If an LDC simply provides the correct numbers requested, the likelihood exists that the LDC is not capturing the

[34] OEB, "RRR Submission Quick Tips for Distributors and Transmitters," Dec. 31, 2007, p. 8. http://www.oeb.gov.on.ca/documents/tools/efiling/RRR_Submission_Tips.pdf

EWMPs. The LDC, in some cases, needs to mine metering and other data and then ask for a RRR correction by exception to ensure that its throughput data is correct.

There also appears to be, possibly as a result of the manner of data collection, legitimate confusion over how many LDCs have EWMPs connected to their systems. While our inquiries to Board Staff indicate that there are “approximately 9”, our inquiries to the IESO indicate there are 19. Care must also be taken to ensure that the wholesale market participants are “embedded” in the distribution system.

Although the prevalence of EWMPs may suggest the issues can wait for later IRM consultations, this is an issue of increasing importance for LDCs. The reason is that, through no fault of their own, LDCs will increasingly lose throughput volumes as customers act to meet government policy objectives by installing behind-the-meter “distributed” generation. The size of the throughput volumes would be important to any LDC’s benchmarking.

The stakes are high for LDCs in “behind-the-meter” customer-owned generation, which would include customers that are billed by the LDCs and embedded wholesale market participants, because the customers will still require connection to the LDC. In practice, many of these customers will only generate when their marginal costs for generating in relation to the market price for power create the right economic conditions to do so. Indeed, an LDC is typically required to maintain reserve capacity on its distribution system for a customer with embedded generation, meaning additional costs are incurred even though all or part of the customer’s load does not show up in the current measure of throughout.

A like-for-like comparison of LDCs requires that the throughput data used in IRM benchmarking be collected with sufficient rigour to address all the permutations and system configurations for energy used or generated by wholesale market participants and customers fulfilling government objectives for distributed generation (particularly when it is on the customer’s side of the meter).

In our view, energy throughput efficiency is an important measure and the robustness and effectiveness of the benchmarking will be diminished without this data correctly incorporating the LDC’s “embedded” wholesale market participants and customers with “behind-the-meter” generation.

Recommendation 9: Data Quality and Rigour

> ***“Ensure the greatest degree of accuracy in the data inputs used in LDC benchmarking for IRM, possibly as part of the transition to IFRS, recognizing that an LDC should not benefit from the incorrect or non-comparable data being used in a rewards-based benchmarking framework.”***

This recommendation is being offered to draw attention to the importance of data quality and data rigour in IRM benchmarking. We believe this issue is important to the integrity of the benchmarking results and the confidence of the LDCs being benchmarked in the IRM framework.

While we make this statement, we believe that the basis for a rigorous data set is in place and that the Board is to be commended for the progress that has been made to date, given the sheer number of LDCs and the short period of time that the Board has been regulating the LDCs.

Our review of the most recent PEG results suggests there continues to be questions of data comparability that may be affecting the outcome of benchmarking. An argument could be made that data quality and rigour problems will be addressed in the fullness of time as incorrect data is re-filed in the correct fashion, but our concern is that some of the top ranked LDCs in both the econometric and unit cost (peer group derived) rankings may be receiving the benefit of inappropriate data or misclassification.

Going forward, we would recommend that additional effort and resources be devoted to tasks like reviewing data filing instructions and performing data sensitivity tests to ensure the highest level of data quality and rigour. Another source of ideas for improved data quality can be found in the comments of intevenors and the Board in EDR applications, where individual decisions may provide indications of general data problems.

The coincidence of the implementation of 3rd generation IRM and the transition to IFRS presents a unique opportunity in this regard.

In our view, the robustness of the Board's benchmarking will be enhanced by such efforts.

Appendix 1: List of Signatories to CEIRM

Coalition for an Effective Incentive Rate Mechanism
c/o Cameron McKenzie, Director of Regulatory Affairs
Horizon Utilities Corporation
55 John St. North
Hamilton, ON L8R 3M8

(905) 317-4785; cameron.mckenzie@horizonutilities.com

	LDC	Contact	Customers*
1	Brantford Power	George Mychailenko, CEO, Heather Wyatt, Reg. Officer	37,108
2	Enersource Hydro Miss.	Jon Bonadie, Manager, Capital and Rates	183,715
3	ENWIN Powerlines	Andrew Sasso, Director, Regulatory Affairs	84,757
4	Erie Thames Powerlines	Graig Pettit, Manager of Regulatory Affairs	14,181
5	Guelph Hydro	Art Stokman, President	47,720
6	Greater Sudbury Hydro	Stan Pawlowicz, Vice President, Corporate Services	43,167
7	Halton Hills Hydro	Tracy Rehberg-Rawlingson, Regulatory Affairs Officer	20,214
8	Horizon Utilities	Cameron McKenzie, Director, Regulatory Affairs; Neil Freeman, VP, Business Development	232,493
9	Hydro Ottawa	Lynne Anderson, Chief Regulatory Affairs Officer	287,006
10	Innisfil Hydro Dist.	Laurie Ann Cooledge, CFO/Treasurer	14,120
11	Kenora Hydro	Dave Sinclair, President and CEO	5,642
12	London Hydro	Vinay Sharma, Vice President, Customer Services	142,105
13	Norfolk Power Dist.	Alvin Allim, Manager of Finance	18,641
14	North Bay Hydro	Todd Wilcox, President & Chief Operating Officer	23,642
15	Oakville Hydro	Cristina Birceanu, Manager, Regulatory Affairs	59,883
16	Oshawa PUC Networks	Vivian Leppard, Regulatory Analyst	50,980
17	PowerStream	Paula Conboy, Dir., Regulatory & Government Affairs	236,220
18	PUC Distribution	Terry Greco, Treasurer and Vice President, Finance	32,512
19	Thunder Bay Hydro	Robert Mace, President	49,421
20	Tillsonburg Hydro	Steve Lund, General Manager	6,571
21	Toronto Hydro	Colin McLorg, Manager, Regulatory Affairs	679,913
22	Veridian Connections	George Armstrong, Manager of Regulatory Affairs	109,225
	Total		**2,379,236**

NB: All signatory LDCs have provided email confirmation of their support for the CEIRM submission.
* Customer numbers taken from: OEB, *2007 Yearbook of Electricity Distributors*.
http://www.oeb.gov.on.ca/OEB/_Documents/Documents/2007_electricity_distributors.pdf

Appendix 2: IRM "Underlying Principles"

There are two instances where the Board has outlined "underlying principles" for 3rd Generation IRM, listed below as A and B.

A) Ontario Energy Board, 3rd Generation Incentive Regulation for Electricity Distributors: Staff Scoping Paper (EB-2007-0673 August 2, 2007)

http://www.oeb.gov.on.ca/documents/cases/EB-2007-0673/scoping_paper_20070802.pdf

Excerpt pp. 2-4 under Principles Underlying the Development of 3rd Generation IRM

The Board's responsibility is to set rates that are just and reasonable. The legislative framework provides the Board the discretion to select the most appropriate approach to rate-setting. The Board's guiding objectives are set out in section 1 of the Ontario Energy Board Act, 1998.

Regulation that promotes economic efficiency in the energy sector ultimately serves the best interests of ratepayers, investors and the province as a whole. Incentive regulation, benchmarking and service quality standards are all tools that contribute to the advancement of that aim.

Building upon this foundation, Board staff believes that the Board's statutory responsibility is best fulfilled, and its statutory objectives in relation to electricity are best promoted, using a multi-year rate-setting methodology that is designed on the basis of the following principles:

1. The financial viability of the electricity distribution sector should continue to be balanced with the interests of consumers. This requires a consideration of the impacts of rate adjustments while at the same time ensuring that prudently incurred costs required for the operation of a distribution system are recovered from customers.

2. The pursuit of economic efficiency should be encouraged. 3rd Generation IRM should encourage greater economic efficiency by providing incentives for the implementation of sustainable operational efficiency improvements. The benefits of these efficiency improvements should be shared by customers and shareholders.

3. The incentive regulation framework must be sustainable. During the 2006 consultation process on 2nd Generation IRM, many participants expressed their views and expectations for 3rd Generation IRM. In addition to specific comments on the various elements of an incentive regulation regime such as an inflation factor and an X-factor, other fundamental issues of concern and debate included capital investment under incentive regulation, lost revenue due to changes in consumption, distributor diversity and the role of service quality regulation. Some of these matters were touched on, but not thoroughly examined, in the development of the 2nd Generation IRM. In general, the expectation expressed by stakeholders was for a longer-term comprehensive incentive regulation framework that may be applied uniformly (in terms

of principles and methodology, but not necessarily the specific adjustments) to all rate-regulated electricity distributors in Ontario.

4. Rate volatility should be minimized. This should provide an environment where consumers and electricity distributors are better able to plan and make decisions.

In addition, the rate-setting methodology should be predictable, understood by all participants, and capable of implementation through a regulatory process that is efficient while at the same time addresses the concerns of interested parties and ensures openness and transparency. The costs of administering the methodology, including the costs imposed on all participants, should not exceed the benefits to be derived from the methodology.

B) Ontario Energy Board, "Underlying principles for development of 3rd Generation IRM," slide 9 of staff presentation titled "Proposed Approach & Work Plan," to the IRM working group meeting October 26, 2007.

http://www.oeb.gov.on.ca/documents/cases/EB-2007-0673_filings/workinggroup/meeting_20071026/6_3rd_Generation_IRM_20071026.pdf

Underlying Principles for Development of 3rd Generation IRM

1. All specific requirements of the legislation and regulations should be addressed
2. The IR framework should protect customers and result in prices for regulated services that are just and reasonable.
3. The IR framework should discourage cross-subsidization between regulated and competitive services.
4. The IR framework should encourage greater economic efficiency by providing the appropriate pricing signals and a system of incentives to maintain an appropriate level of reliability and quality of service.
5. The IR framework should permit the utility an opportunity to earn a reasonable return on shareholder capital and to maintain its financial viability.
6. The IR framework should be transparent and as simple as possible. The cost of administering IR, including costs imposed on all participants, including the regulated entity and the regulator, should not exceed the benefits available from IR.
7. IR should allocate the benefits from greater efficiency fairly between the utility/shareholder and the customers.
8. A IR framework should be flexible and able to handle changing and varied circumstances.
9. The IR framework should facilitate the use of efficient processes.
10. Provide predictability and stability in rates so as consumers and electricity distributors are better able to plan and make decisions.

Appendix 3: Potential Line Density Based Peer Groups*

Greater than 50	Cust./km
Hydro Ottawa	50.01
Veridian Connections	52.87
Oshawa PUC Networks	53.49
Woodstock Hydro Services	53.88
London Hydro	54.47
Hydro 2000	55.19
West Perth Power	56.50
Erie Thames Powerlines	56.50
Midland Power Utility	58.34
Essex Powerlines	59.25
West Coast Huron Energy	59.28
Peterborough Distribution	62.68
Orangeville Hydro	63.74
Middlesex Power Distribution	65.63
St. Thomas Energy	66.33
Rideau St. Lawrence Distribution	67.40
Toronto Hydro-Electric System	69.24
Horizon Utilities	69.55
Cooperative Hydro Embrun	69.70
Festival Hydro	70.30
Dutton Hydro	71.05
E.L.K. Energy	73.42
ENWIN Powerlines	74.81
Grand Valley Energy	75.22
Brantford Power	75.73
Kingston Electricity Distribution	76.53
Clinton Power	78.05
Lakefront Utilities	79.45
Hydro Hawkesbury	83.51

From 25 to 50	Cust./km
Milton Hydro Distribution	27.38
Norfolk Power Distribution	28.46
Brant County Power	29.18
Fort Erie	29.51
Port Colborne	29.55
Newmarket Hydro	30.17
Waterloo North Hydro	32.56
Enersource Hydro Mississauga	35.47
Whitby Hydro Electric	37.49
PowerStream	38.10
Burlington Hydro	39.91
Chatham-Kent Hydro	40.93
Grimsby Power	41.67
Orillia Power Distribution	41.88
Niagara Falls Hydro	42.37
Centre Wellington Hydro	42.73
Oakville Hydro Electricity	42.87
Tillsonburg Hydro	42.95
Cambridge and N. Dumfries Hydro	44.45
COLLUS Power	44.49
Kitchener-Wilmot Hydro	44.89
Guelph Hydro Electric Systems	46.33
Hydro One Brampton Networks	46.64
Barrie Hydro Distribution	47.43
Wellington North Power	47.75
Bluewater Power Distribution	48.13
Welland Hydro-Electric System	48.83
Westario Power	48.96
Wasaga Distribution	49.39
Newbury Power	49.75

Less than 25	Cust./km
Great Lakes Power	6.32
Hydro One Networks	9.76
Haldimand County Hydro	12.13
Sioux Lookout Hydro	13.05
Peninsula West Utilities	13.89
Halton Hills Hydro	15.04
Northern Ontario Wires	16.52
Eastern Ontario Power	18.12
Atikokan Hydro	18.60
Innisfil Hydro	22.17
Niagara-on-the-Lake Hydro	23.08
Espanola Regional Hydro	24.20

Shield Urban from 25 to 60	Cust./km
Lakeland Power Distribution	25.73
Parry Sound Power	26.29
North Bay Hydro Distribution	38.88
Hearst Power Distribution	40.76
Thunder Bay Hydro Electricity	42.60
PUC Distribution	44.84
Fort Frances Power	46.00
Chapleau Public Utilities	49.56
Greater Sudbury Hydro	51.82
Kenora Hydro Electric	57.57
Ottawa River Power**	70.07
Renfrew Hydro**	75.44

* Source: Line density figures are from 2007 RRR. The calculation is "Total Customers (not including Street & Sentinel Lighting Connections)" divided by "Total KM of Line".
** NB: Renfrew Hydro and Ottawa River Power were not moved from the "northern" LDCs for the purposes of the peer grouping in the coalition submission only because the peer grouping and "northern" recommendations were treated separately. The "Urban Shield" group would not have LDCs above 60 customer kilometre.

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