IN THE MATTER of the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF a consultation by the Ontario Energy Board with respect to the identification and calculation of Direct Benefits for the purpose of Ontario Regulation 330/09 and Section 79.1 of the OEB Act.

SUBMISSIONS

OF THE

SCHOOL ENERGY COALITION

1. On September 25, 2009 the Board initiated a consultation process with respect to the identification and calculation of direct benefits for the purpose of OReg 330/09. As set forth in that process, the Board released a Staff Discussion Paper (the "Proposal"), and has sought comments on the Proposal from stakeholders. These are the submissions of the School Energy Coalition.

2. Our submissions are organized as follows. First, we provide a brief introduction to the context of the issues. Then, we respond to the fourteen questions posed in the Proposal, under the same headings as are set forth in Appendix 1 of the Proposal.

General/Context

3. The expansion and reconfiguration of the distribution systems in Ontario to accommodate and encourage greater renewable energy generation has been mandated by the government of Ontario in the *Green Energy and Green Economy Act*, 2009 ("GEGEA"). The incremental capital and OM&A spending that will result is likely to be substantial, as evidenced by the initial Green Energy Plan of Hydro One, already measured in the billions of dollars. This government initiative has been called, by many international environmentalists and commentators, the most forward-thinking and progressive shift in energy generation policy in the world.

4. The shift to greater reliance on renewables is not expected to have uniform impacts throughout the province. Largely because renewable resources simply are where they are, the generation of renewable electricity is likely to be concentrated in specific areas of the province. As the Proposal notes, the Hydro One area, and in particular rural parts of that area, accounted for 70% of all renewable generation under the former RESOP program, and

in our estimation this imbalance is likely to continue or even expand as the FIT program gains traction. The RESOP history – only 10 LDCs had material RESOP activity – is likely to continue.

5. It is arguable that the costs associated with implementation of GEGEA, on all levels, are at their essence costs associated with the energy commodity, and therefore all GEGEA costs should be socialized across all customers of the commodity in Ontario. Thus, while in terms of the types of costs, they for the most part appear to be costs of building and maintaining the distribution system, in terms of cost causality they are costs of generating and supplying the preferred electricity to Ontarians.

6. The Legislature, in Section 79.1 of the OEB Act, and in OReg. 330/09, has rejected that simple approach – allocation of all GEGEA costs to the commodity through some form of province-wide socialization of those costs - in favour of a specific division of those costs between local ratepayers and province-wide electricity consumers.

7. Our interpretation of the Act and the Regulation applicable is that the primary mandate is to protect the local ratepayers from the incremental costs of GEGEA compliance. If $100 is spent to allow the system to accept more renewable generation, prima facie the local ratepayers should not have to bear that as a distribution cost. The cost should be borne by the consumers of that generation. However, if the local ratepayers experience a collateral saving of $3 because of that $100 spent, then their real cost of GEGEA compliance was only $97. It is only that $97 that is a true generation cost. The "direct benefits" analysis is the identification and quantification of that $3 offset. The remainder is the "rate protection" amount that must be shifted from local ratepayers to electricity consumers.

8. We note that there are two impacts of determining what component of GEGEA costs have been offset:

   a. ***Geographical.*** The more obvious impact is based on geography. The greater the amount of the direct benefits, the more disproportionate is the percentage of GEGEA costs borne locally. In simple terms, if 70% of GEGEA compliance costs are in the Hydro One area, but only 25% of the customer load, then "direct benefit" amounts are allocated 70% to Hydro One customers, but "rate protection" amounts are allocated 25% to Hydro One customers.

   b. ***Customer Classes.*** The costs of building and maintaining the distribution system are allocated between customer classes differently from the costs of the commodity (which will include the rate protection amount). The most striking example of this impact is that "rate protection" amounts will be borne much less by residential customers (potentially less than half) than would "direct benefits" amounts.

9. Since the amount of money to be spent on this initiative is likely to be several billion dollars, the Board's policy on the identification and calculation of direct benefits could, depending on the Board's choices, result in substantial shifts in cost responsibility between customer groups.

10. The balance of our submissions below deal with each of the fourteen questions posed by Staff in turn.

<u>Identifying the Direct Benefits</u>

11. As is clear from our interpretation of OReg. 330/09, set forth above, in our view a "direct benefit" is a dollar amount saved by local ratepayers as a result of an eligible investment. It is, in essence, an offset to the gross cost of the eligible investment to get to the net cost, which is the real cost of GEGEA compliance.

12. In keeping with the concept of an "offset" to arrive at the net cost of an eligible investment, we agree with Staff on the two principles set forth on page 6 of the Proposal, i.e. benefits must be "directly attributable" to the local ratepayers, and they must be "readily quantifiable" in dollars.

13. With respect to the "directly attributable" principle, in our submission this must be attributable to the local ratepayers <u>in that capacity</u>. Local job creation, for example, while perhaps the direct result of the eligible investment, is not an offset of a ratepayer cost. It is an indirect or collateral benefit, which may or may not benefit the same people in the same proportions as the cost.

14. By contrast, where local generation reduces expenditures of the utility that it would otherwise recover from the ratepayers, that cost saving must be treated as a direct benefit or the local ratepayers would be getting a windfall.

15. The "readily quantifiable" condition is, in our formulation, a more restrictive test, in which the focus is on actual dollar savings. We submit that unless an impact reduces the net cost to the utility's customers of the eligible investment, it is not a direct benefit. That is, the utility would have to be able to identify a cost it was required to, or planning to, incur that it no longer has to incur (or is reduced) for a direct benefit to arise.

16. A good example of the latter point would be service quality. If Hydro One ends up spending several billion dollars improving its distribution system, largely in rural areas, to accept more renewable generation, the SQIs for the rural customers are likely to improve in some areas, perhaps dramatically. There is clearly a benefit to those customers, but – and this is the key – it is not a benefit that, but for the GEGEA spending, was prioritized and would have been achieved.

17. The SQI example can arise in two ways:

    a. In the first case, an upgrade in, say, a substation to accommodate renewable generation is spending that otherwise would never have been made at all. From a cost causality point of view, the sole reason for that spending is GEGEA. The fact that the quality of service to some local customers would also be improved is accidental. Local ratepayers should not have to bear that cost. Local ratepayers should bear costs that arise out of proper planning to meet their needs. Any additional costs are not properly allocated to them.

b. In the second case, a similar upgrade represents spending that would still have been made at some point in the future, but not today. The GEGEA initiative has accelerated the cost, but a collateral result is that better service quality that would have been enjoyed by some local ratepayers ten years from now will instead be available today. In our submission, the direct benefit amount is the spending foregone in the future, when it would otherwise have been incurred, and the collateral benefit to service quality today is irrelevant.

18. In these, and in other examples used below, we are basing our analysis on a conceptual approach in which capital and operating expenditures of the LDC have a baseline, which assumes no GEGEA spending. That baseline is all of the amounts that local ratepayers should bear. When GEGEA spending is layered on top of that, there will be incremental spending, but the underlying budget will also be affected. It is the net overall impact on the underlying budget that should be identified as "direct benefits".

19. In the simplest case, a utility is planning to spend $10 million this year, without considering GEGEA. Development of a Green Energy Plan identifies $2 million in necessary spending, but when the overall budget is put together, the total is only $11.7 million. The rate protection amount should be $1.7 million, because the baseline budget has been reduced by $0.3 million as a consequence of the GEGEA spending.

20. In the real world, of course, the simple example is complicated by capital vs. operating spending, timing, etc. However, the concept, after working through those details, should in our view be the same. Simply put, subject to the ongoing OM&A costs (see Proposal, page 4), the difference in revenue requirement between no-GEGEA, and with-GEGEA should end up being the rate protection amount. If the eligible investment impact on revenue requirement is more, the difference is the direct benefit properly borne by the local ratepayers.

21. ***Issue 1: In addition to the two types of direct benefits identified above (reduced transmission and WMSC charges, improved capability of the distribution system), should the Board take into account any other direct benefits that accrue to the customers of the distributor making the investment?***

22. In keeping with our comments above, therefore, we believe that reduced external charges are an appropriate category of direct benefits. We do not, however, believe that improved capability is an appropriate category. That category, instead, should be "**capital and operating expenditures avoided as a direct result of spending on eligible investments**".

23. We note that, while this appears to be a narrow approach, the Board should keep in mind the other impacts of GEGEA compliance on local ratepayers. LDCs will be increasing their OM&A to add GEGEA-related resources, at the expense of local ratepayers. Some upstream capital spending will be required by local distributors that, while nominally the responsibility

of generators, will end up being borne by local ratepayers. These and other hidden local GEGEA costs will in part be offset by improved service quality in some areas, and perhaps some reduced line losses. It would appear to us that these various indirect impacts are in a separate category, and while it is hoped that these costs and benefits will be reasonably balanced, that result is not assured. Thus, ensuring that the rate protection amount is not reduced for any of these indirect impacts is a fair and equitable result for the local ratepayers.

24. Given our support for the "reduced charges" concept, and our view that "improved capability" should be replaced with an "avoided cost" approach, we have not identified any further categories of direct benefits.

<u>Quantifying the Direct Benefits – Reduced Charges</u>

25. We agree with the Proposal that the direct benefits associated with reduced network transmission and WMSC charges is most appropriately calculated on an *ex-post* basis.

26. ***Issue 2: Are there any circumstances under which a distributor should be permitted to deviate from the proposed ex-post approach and use an ex-ante (i.e. forward looking forecast) approach?***

27. In our submission, this policy should operate in a manner similar to other Board policies, i.e. it is always open to an applicant or an intervenor to propose a different method of calculation, as long as they can show with compelling evidence that in the particular circumstances it will produce a more reliable result. As a practical matter, we believe it would be a rare situation in which a different method would successfully supplant the Board's policy, but it should continue to be an option.

<u>Quantifying the Direct Benefits – Capability/Avoided Cost - Principles</u>

28. ***Issue 3: Are there any potential refinements to the proposed Guiding Principles discussed above?***

29. The Proposal includes six suggested Guiding Principles on pages 11 and 12, and we have comments on each.

30. The first principle is the combination of "directly attributable" and "readily quantifiable", which we have discussed in detail earlier. Our focus is tighter than that in the Proposal, emphasizing which costs have been avoided, and therefore which should reasonably be considered offsets to the costs associated with eligible investments.

31. The second principle is that the level of detail should vary depending on the distributor. In our view, this principle is not appropriate as currently proposed.

32. In general, we believe that having different rules for smaller and larger LDCs is not fair to ratepayers, because it doesn't give all ratepayers the same level of protection. As well, it is

not in the interests of the sector, because it allows less rigorous standards to be applied so some LDCs. We have expressed this same view in a number of other proceedings of various types.

33. That having been said, it is true that eligible investments of some distributors will be much larger and more complex than others. Investing significant resources to measure an insignificant amount is not generally good regulation. This, however, is about how much the LDC is spending on eligible investments, not the size of the distributor. Simply put, if Toronto Hydro and Atikokan Hydro spend the same amount on eligible investments, their responsibilities in the calculation of direct benefits should be the same.

34. It follows that, if the amount spent by LDCs on eligible investments differs, in the appropriate circumstances a different calculation regime may be available where the spending is small. We comment later on the specifics of the Proposal in this respect.

35. The third and fourth principles propose that use of eligible investments by load customers should be quantified as direct benefits. These principles could depart from the principle of avoided cost, and to that extent they are, in our view, too broad.

36. Two paradigms should be contrasted:

   a. In the first case (the third principle), a new distribution line is built to serve renewable generation. New load customers, who were not previously served, also connect to the line. The cost of the new line should be allocated reasonably between load and generation customers. Since neither is incremental to the other, the normal principles of cost allocation should apply.

   b. In the second case (the fourth principle), an existing distribution line is replaced with an upgraded one so that it can handle renewable generation. The fact that the new line will serve load customers is irrelevant. They already had a perfectly good line, and the LDC didn't need to spend any more to serve that load. The only reason for the incremental spending was to serve the generation customers. The only direct benefit would be that associated with the future replacement of the line when it normally would have needed replacement due to aging. That future replacement has now been delayed, which benefits the load customers in the future.

37. In our submission the use of eligible investments by load customers is only relevant to the extent that present or future costs have been avoided by that use.

38. The fifth principle relates to service quality. As we have said earlier in these submissions, service quality improvements by themselves should not be considered direct benefits. Rather, where costs to improve service quality were necessary and/or planned, and those costs have been avoided due to the eligible investment, those avoided costs should be considered direct benefits at the time they would have been incurred.

39. The sixth principle relates to line losses, and perhaps other (undefined) benefits. We do not see the value of this principle. We agree that line losses should not be direct benefits (unless there are avoided costs, much like our service quality example above), but we are unclear on how the principle proposed has a generic application. To our minds, line losses are excluded because of the first principle, in keeping with our earlier discussion.

40. ***Issue 4: Should any additional Guiding Principles be considered by the Board?***

41. Subject to our comments above, we have not identified any additional Guiding Principles that would be appropriate.

Quantifying the Direct Benefits – Capability/Avoided Costs - Criteria

42. As noted earlier, we start with the concept that there is a baseline cost (revenue requirement) that must be incurred to serve current and, as time progresses, future load customers. This cost should be borne by the load customers. There may then be additional annual costs associated with capital and operating expenditures not required but for the GEGEA. All incremental costs of complying with GEGEA should be included in ratepayer protection. In the small number of cases in which costs are incurred for both purposes (see para. 36(a) above), then a normal cost allocation based on cost causality should apply.

43. Our comments on the proposed criteria, below, test those criteria against this conceptual approach.

44. ***Issue 5: Are there any potential refinements to the proposed criteria discussed above for the purpose of estimating the direct benefits?***

45. ***Issue 6: Are there any other criteria that the Board should potentially take into consideration or should certain criteria listed above not be taken into account? In proposing the addition and/or elimination of certain criteria, a solid business case should be made for the Board to consider the merits.***

46. The Proposal includes seven criteria. We deal with each of them in turn.

47. The first criterion proposes allocation between users for "new, upgraded or replacement assets".

48. In general, we do not agree with this criterion. As noted earlier, where assets are built or acquired for the purpose of serving both new load and new generation customers, and the generation does not affect the timing of the expenditure, then a straightforward allocation between users is appropriate. The same would be true if non-qualifying vs. qualifying generators are intended to share a new asset.

49. However, in any other case the allocation must, in our view, be more nuanced. Three examples show how we believe allocation should be done:

a. If the LDC needs a new line, for example, for both load and generation customers, and would have built it at the same time if either load or generation alone required it, it is appropriate to treat part of the capital cost of that asset as serving generation, and part as serving load, with the latter being a direct benefit.

b. If the LDC needs a new asset for generation customers, and expects that in the future it will also be used for load customers, the entire capital cost should be treated as incurred for generation purposes (i.e. no initial direct benefits), but in the future year in which the load customers were expected to be added, a direct benefit should be calculated based on the shared use of the asset from that point onward. In our view, the future benefit should not be present-valued. The local ratepayers should not be required to bear any costs associated with the eligible investment until the point in time they would have had to incur costs in the normal course.

c. If the LDC needs an upgraded or replacement asset for generation customers, which will also be used for load customers, no part of the cost of the asset should be borne by load customers immediately, since there is no net benefit, and no cost avoided, at the outset. Instead, in the future year in which the replacement or upgrade would have otherwise taken place (but for the generation customers), a direct benefit should be calculated based on the shared use of the asset from the point onward.

50. The second criterion is the recognition of any expected load growth that would require the expenditure at some point in the future in any case. For the same reasons as we have set forth above, this should in our view be recorded as a direct benefit only at the point when the costs would otherwise have been incurred.

51. The third criterion relates to the vintage and condition of replaced assets. This should be a factor in the calculation of direct benefits in the same way as future load growth and other timing issues. As with the previous points, we believe the direct benefit only arises in the year in which the spending would otherwise have occurred.

52. The fourth criterion relates to the size of the renewable generator. In our view, this is not an appropriate criterion.

53. It is the eligible investment spending that must be assessed to determine direct benefits. The renewable generator projects are largely irrelevant. For example, if an LDC has to reconfigure a line because several residents in a particular subdivision install solar PV systems, the size of those installations doesn't matter; the size and nature of the eligible investment is what matters. In the same way, if a 10 MW windfarm can be accommodated on existing assets with minor changes, the fact that the windfarm is 10 MW is not a factor in the direct benefits calculation. The small amount of spending, on the other hand, may well be a factor.

54. The fifth criterion relates to service quality. As earlier discussed, in our view service quality impacts are not, in and of themselves, direct benefits. Where the cost of a service quality

improvement that was necessary and/or planned has been avoided, that avoided cost is a direct benefit.

55. The sixth criterion relates to line losses. We agree with the Proposal that this should not be a factor in calculating direct benefits.

56. The seventh criterion relates to alternative approaches. We agree with the Proposal.

57. ***Issue 7: Is a ranking or weighting of the criteria above necessary? If so, please propose an appropriate ranking or weighting, from most to least applicable, and provide a supporting justification.***

58. On the conceptual approach to the calculation that we have proposed, no ranking or weighting is required.

59. ***Issue 8: Are there any information limitations that may prevent certain distributors from providing an assessment of any criteria above?***

60. ***Issue 9: In the absence of having the best available information possible (e.g. recently completed study), are there any factors above for which a distributor would not be able to provide a reasonable estimate?***

61. ***Issue 10: What information should all distributors already have on hand (e.g. for distribution planning) that would allow for a reasonable estimate that is specific to certain areas of a distributor's territory of: (1) load growth; and (2) customer density?***

62. We have proposed that the distributor essentially compare annual spending with eligible investments to a baseline in which there are no eligible investments. Most distributors now have multi-year capital and operating plans, now with increasingly rigorous asset condition assessments, long term growth forecasts, etc. Proper distribution system planning requires this. Any distributor expecting significant eligible investments would have to forecast not only those investments, but also their effect on their baseline plan. There will be overlap, and some aspects of the baseline plan will have to be altered to accommodate the addition of the new priority. There are many conventional methods of calculating the delta between the baseline and the revised plan.

63. Going forward, we anticipate it will be more difficult for distributors to do this calculation when the only multi-year plan they have already includes some eligible investments. While we believe that assessing the impact of new spending on the existing plan and its components, whatever they are, will still be possible, this is not an immediate problem. In three or four years, when it starts to be an issue, the Board and distributors will have learned more about how eligible investments are creating impacts on the load-serving aspects of the system, and more sophisticated methods of comparing increment to baseline should be easier to develop.

64. Assuming that a distributor has a multi-year system planning document in place, that document should include location specific forecasts relating to customer growth, density, and spending requirements.

65. ***Issue 11: Where provincial ratepayers have provided rate protection and the asset is not ultimately used by the distributor as an eligible investment, Board staff proposed that the amount of rate protection should be reduced accordingly going forward to reflect the use of the investment for other purposes. In such cases, are there any circumstances under which the amount of rate protection provided by provincial ratepayers should not be reduced? If so, please explain.***

66. This is a classic stranded asset problem. If a utility acquires or builds assets for a particular purpose, and then that purpose is frustrated or ended, someone still has to bear the cost. The cost normally is allocated in the same manner as it originally would have been allocated if the purpose had been carried out, unless the customer or class that would have borne it no longer exists. In this case, barring any change in circumstances, if an eligible investment is 100% applicable to renewable generation (and none to load) at the outset, then it should be 100% included in rate protection, and that should not change if the renewable generation project is cancelled. We understand that the Proposal agrees with this.

67. Then, Staff proposes a practical variation, which is that, once built, the asset is put to other uses. We believe there are two potential circumstances in which this could happen, with different results appropriate:

   a. In the first case, the asset would have at some point been used for load customers anyway, so in the changed situation that still takes place, but without the renewable generator using the asset as well. In this situation, the cost should be allocated between direct benefits and rate protection (load vs. "generation") as if the renewable generation project had proceeded. There is still a component of the asset that is stranded, and an allocation of this type would fairly allocate between load and stranded asset. The latter should continue to be included in rate protection.

   b. In the second case, a new or accelerated use of the asset for load customers is found after the renewable generation project is cancelled. In this situation, it is appropriate to determine what spending would have occurred for that new or accelerated use, and when. That proportion of the eligible investment should become a direct benefit, and thus the rate protection should be reduced accordingly.

<u>Quantifying the Direct Benefits – Capability/Avoided Cost – Standardized Approach</u>

68. ***Issue 12: Should the Board consider a certain standardized approach? If so, how should the approach be standardized?***

69. ***Issue 13: Would a certain percentage of expansion investments and a certain percentage of REI investments (using a historical "baseline" specific to each distributor) provide a reasonable estimate on a go forward basis?***

70. ***Issue 14: If the Board decided a standardized approach would be appropriate for certain distributors:***

> ***i. What timeframe would be suitable for implementation?***
> ***ii. What would an appropriate threshold be to determine which distributors could proceed under a standardized approach and which distributors should be required to continue under the more rigorous assessment discussed in section 3.3.2.1?***

71. It is our submission that a standardized approach will be appropriate for utilities with smaller amounts of eligible investments. That approach should evolve over time, with the direct benefit percentage starting at zero, and then adjusting annually based on the ongoing weighted average of actual direct benefits (relative to eligible investments) from all distributors who have used the more rigorous calculation method.

72. While we recognize that distributors with smaller amounts of eligible investments should not have to expend disproportionate resources calculating direct benefits, the Board does not yet have any basis on which to establish a standard percentage for lower-spending distributors. In our submission, the Board is given the responsibility under OReg 330/09 to establish an amount for direct benefits, and that can only be done on some supportable basis. Since any percentage would have no supportable basis at this point, the only number that is possible is zero. That is, rate protection equals the amount of eligible investments under the formula, without any deduction.

73. However, as the few distributors that will have substantial GEGEA spending start bringing in their plans for Board review, the Board will develop experience with these plans, and an average percentage of direct benefits to eligible investments can be calculated. As time goes on, that percentage will become more and more sophisticated, perhaps with different percentages for different kinds of eligible investments, or other standard formulae.

74. Because the percentage of eligible investment costs that will be allocable to direct benefits is likely to be fairly small, in our submission starting at zero and working upwards to a sector-wide cumulative average is an effective approach. This is especially true since the utilities with smaller amounts of eligible investments will likely have very little spending in the first few years, while Hydro One and a few others will have substantial spending in that period.

75. One implication of this, of course, is that the Board will have to be especially vigilant that LDCs do not load up spending that is otherwise conventional distribution system spending in the green energy plan because their own ratepayers don't have to bear the cost. However, the Board is already aware that problem may arise as the distributors get used to this new set of rules and procedures. No additional policies are required for the Board to keep on top of this potential issue.

Conclusion

76. We hope these submissions are of assistance to the Board, and would like to continue to be involved in the Board's consideration of this issue going forward.

77. The School Energy Coalition submits that it has participated responsibly in this process, with a view to assisting the Board in an efficient manner, and therefore requests that the Board order payment of its reasonably incurred costs of that participation.

Respectfully submitted on behalf of the School Energy Coalition this 11th day of January, 2010.

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