EB-2007-0630

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.O.15, Sch. B;

AND IN THE MATTER OF the review by Board Staff of Distributed Generation Policies and Rates.

COMMENTS

OF THE

SCHOOL ENERGY COALITION

1. On July 13, 2007 Board Staff published a discussion paper (the "Staff Report") entitled *Distribution Generation: Rates and Connection*, together with a report and review (the "Study") dated June, 2007 by EES Consulting entitled *Discussion Paper on Distributed Generation (DG) and Rate Treatment of DG*. These are the comments of the School Energy Coalition with respect to the Staff Report and the Study.

2. The Staff Report makes a serious effort to organize and make sense out of the issues associated with distributed generation. However, in our view it seeks to simplify what is a much more complex issue than is being presented.

3. The reason the the Staff Report misses some of the key policy issues is, we think, the fact that the Study was particularly unhelpful. Apparently operating from the faulty premise that all distributed generation is largely the same, the Study reaches its conclusions and recommendations based on an oversimplified analysis of what is quite a complex set of issues. It does not appear to us to be an "expert" report. Even the review of policies and rules in other jurisdictions, which would otherwise be very valuable, is less so because we cannot assess whether the consultants correctly identified the relevant policies and rules in each jurisdiction. At the very least, we think this compendium needs to be spot checked for quality control purposes before Board Staff or anyone else rely on it.

4. Because the Study does not, in our view, form a solid foundation for building policies going forward, we have not in these Comments elected to point out every specific problem with the recommendations in the Study, or with the proposals in the Staff Report. We believe that too much additional work needs to be done before a real debate on the details of the issues can be engaged. In addition, the limit in funded hours (30), while initially appearing to be quite high, in fact turns out to be a barrier to carrying out a more detailed analysis of the issues. At this point, we have focused on discussing higher level issues, with the hope that further work by

Board Staff will produce recommendations that take fuller account of the subtleties of the issues in this difficult area.

The Interest of Schools

5. Schools in Ontario are in a fairly unique situation, because they have strong interests in DG issues on both sides of the DG "divide":

   a. ***Owners and/or Hosts.*** As large users with a substantial and predictable load, schools are prime candidates to be owners of, or hosts for, distributed generation facilities. In theory, schools could utilize about 800 MW of generation efficiently. Some schools have already started in this direction, with solar panels, Darius wind turbines (or other VAWTs) or other technologies on their roofs. At some point, ownership of off-site generation (which would be DG) may be the most economic method of ensuring certainty of cost and supply for schools. Indeed, schools have an added advantage with respect to renewables, because they can and do integrate the generation aspects with pedagogical initiatives. Not only can schools replace dirty generation, but they can teach kids the value of doing so at an early age.

   b. ***Affected Ratepayers.*** Schools make up a significant percentage of the general service classes that will be most affected by the cost allocation and rate design decisions associated with standby rates and other aspects of DG. As users of about 2% of Ontario's electricity, they will also be materially affected by the cost and reliability implications of DG policies on the electricity commodity in Ontario. Simply put, if barriers to DG remain high, electricity will be less reliable, and more expensive, and schools (and their students) will pay a substantial price if that occurs.

6. For these reasons, the views of School Energy Coalition are driven by the desire to "have our cake and eat it too". In attempting to draw a balance, reducing the barriers to DG as much as possible, but limiting the cost impacts on other ratepayers, we are in the same position as the Board.

What is Distributed Generation?

7. The thing about DG that is unique is that it is "distributed". Because the generation is distributed, several results arise, including but not limited to:

   a. There is, mathematically, less need to build transmission lines, and that need correlates directly with: a) the geographic diversity of the DG, b) the location of the DG relative to load, and c) the coincidence of the DG generation with load shape (either through natural connections or dispatchability).

   b. There is an increase in security of supply, and that increase correlates with three factors: a) the percentage of DG in the system, b) the geographic diversity of the DG in the provnce, and c) the percentage of DG that uses a common technology or fuel. Security of supply increases for three reasons. First, fewer transmission lines means less vulnerability to attack. Second, transmission disruptions due to natural forces such as storms can be reduced. Third, the danger of common cause failure (all the nuclear stations being offline for the same reason, for example) can be reduced. In the latter case, however, the result is only achieved if there is technology and/or fuel diversity amongst the DG. If all DG is gas-fired, for example, then there is still vulnerability to common factors, such as fuel supply disruption.

c. There are system integrity and operation advantages. Certain types of DG provide the capability to "black start", for example, or provide voltage or other power quality advantages, usually depending on location and technology type.

8. We note that this above list does not include cost or environmental benefits. Generally speaking, the fact that generation is "distributed" does not, by itself, create cost or environmental benefits. It is true, however, that certain technologies, particularly renewables, can be deployed efficiently on a smaller scale and in a distributed configuration, so often when people talk about DG a lot of what they are discussing is environmentally benign or beneficial methods of generating electricity. It is also true that DG is more likely to be owned by private sector enterprises, and thus there can be cost savings through operating <u>efficiencies</u>, and there can be reductions in cost <u>risks</u> due to offloading those risks onto private sector owners. On the other side, DG technologies often enter the market more expensive that conventional technologies, with the expectation that over time those technologies (wind being the best example, and perhaps solar in the future) will become cost competitive.

9. Given the nature of the benefits, it is possible to identify the key distinctions between different types of DG, such as the following, that should inform policy choices:

a. ***Level of dispatchability or load following.*** Interestingly, both highly dispatchable and highly "at will" DG – the two ends of the spectrum – place more demands on the distribution and transmission systems than DG operating at a more baseload or direct load following basis. Issues like standby fees and interconnection costs can be influenced by this factor, as for example in our discussion below under the heading "DG as CDM". As well, questions of how costs and benefits should be allocated" between the commodity price and the distribution rates can arise in this context.

b. ***Own load vs. grid supply.*** Much of the Study and the Staff Report build in an implicit assumption that DG is located at the site of load. This is not always, or even mostly, the case. The Standard Offer program, for example, operates on the assumption that the DG facility will feed the grid, not a host load. DG that feeds host load will not qualify for the program. Whether there is host load will affect things like the type and cost of interconnection (largely a supply side issue), the need for standby fees (largely a load displacement issue), etc. In the next twenty years, we estimate that more than half the DG in Ontario will not have a host load.

c. ***Proximity to load centres.*** Calculation of the costs and benefits of DG, and therefore the rates to be charged for them to connect to the system, and the rates they are paid for the commodity they sell, are heavily influenced by how close the DG facility is to load. Of course, if there is a host load then this benefit is maximized. Conversely, a wind turbine in a field north of Hearst may create rather than reduce system costs.

d. ***Proximity to other DG, central generation, or interties.*** In the same way, if a DG facility is built in an area where there are many others, the benefits it produces may be muted from some factors (for example, avoidance of transmission capex), but enhanced from other factors In the case of the latter, consider the effect on backup rates if an LDC has several facilities in the same area. There is some probability that the cost to have backup available is reduced, because the likelihood of all needing it at the same time is small. If DG is clustered around a nuclear facility or a major intertie to a neighbouring jurisdiction, its value may also be reduced.

e. ***Types of energy supplied.*** One aspect that, in an industrial province like Ontario, should be very important is the possibility that DG will supply not only electricity but also process or space heat, and perhaps additional energy supplies in the future (hydrogen fuel for vehicles, for example). Cogeneration or trigeneration can have tremendous environmental and cost benefits, but it also creates operational restrictions that limit the flexibility of electricity generation. The Board should consider, in formulating policies such as standby rates, interconnection costs, etc., how both the positive and negative impacts of combined heat and power should be reflected.

f. ***Technology or Fuel source.*** Clearly some technologies produce less damage to the environment, and some produce more reliable generation, etc. Is there any sense in which the same policies should apply to four wind turbines in a farmer's field, feeding up to 10 MW into the grid when the wind blows, and a reciprocating engine running on gasoline that is available when required for critical peak power?

g. ***Who is buying the power?*** For some DG facilities, they sell to the grid on a Standard Offer contract at a predetermined fixed price. For others, they displace the cost to the host load of buying power from the grid (for example through net metering). For still others, generation occurs in one location, and the power is sold to a private customer in another location, so that the cost of the intervening system has to be considered.

10. We could, of course, give numerous other examples, but these demonstrate the point. It is, in our view, not good policy to create a one-size-fits-all set of rules for all types of DG throughout the province. The Board, in establishing rules, should deal with each of the major distinctions above head on, and determine what policies and rules are appropriate for each of the various types of DG.

11. In this regard, we note that the Study uses some arbitrary limits to identify what counts as DG (page 11), such as 5 MW for wind and 100 kw for PV. These limits are counterproductive, and can lead to bad policies. For example, does it make sense to treat a 2 MW single wind turbine in a farmer's field, selling under the Standard Office rules, differently than 2 MW of PV in that same farmer's field, also selling under the same program. What about if the same farmer instead decides to install a 2 MW anaerobic digestion system? Different rules again? In fact, there may be different rules appropriate for these different systems, but they would not

be based on facility size. They may be based on dispatchability, environmental benefits, system benefits, power quality, or the like.

12. We are particularly concerned about these arbitrary definitions because they would exclude many of the province’s most important DG facilities. In 1992, the Independent Power Producers’ Society of Ontario (now APPrO), produced a series of studies showing a total technical potential for DG (in the broadest sense) in Ontario of 22,634 MW. Of this, about half (11,236 MW) was cogeneration, which is one of the most beneficial types of DG from a system point of view. It also included 6,390 MW of wind, 2,325 MW small hydro (ie. under 20 MW facilities), 1,842 MW of wood generation, and 841 MW of other technologies (such as landfill gas, sewer gas, etc.).

13. The EES Study would include in its definition of DG, for example, the 258 MW of cogeneration that IPPSO identified as technically feasible at over 1000 secondary schools, but would not include the almost 2,200 small hydro facilities that could be build on rivers around the province. It would include some of the 299 wind sites (168 of them, totalling 840 MW), but would not include many more that would in fact qualify under the Standard Offer program.

14. In fact, the IPPSO study is 15 years out of date, and it is likely that the DG capability in the province of Ontario is more than was then forecast. In our view, there is every reason to believe that many different types and sizes of DG will be installed in Ontario, in considerable numbers, over the next decade or more. It is critical that the Board’s policies take account of not only the sheer size and importance of this generation source, but also the diversity within the DG option.

DG as CDM

15. Both the Study and the Staff Report appear to ignore or reject the notion that some types of DG are comparable to CDM. This is an important policy issue that the Board needs to address.

16. Take an example. A commercial/industrial complex decides to replace its conventional air conditioning system with one that operates at much higher efficiency, thus reducing its peak load by 1 MW. One of the issues with the higher efficiency equipment is that it is more tempermental (as is often the case), and so from time to time it will break down and a combination of conventional backup AC, and electric fans, will allow the employees to continue to work. The identical complex next door chooses to solve the same problem a different way, by installing a 1 MW natural gas driven engine that produces both electricity and process heat. It operates to follow load, so that it is not selling into the grid. It can also break down, in which case backup power would be required.

17. Take another example. Homeowner A instals solar panels on his roof, saving 50 kw of capacity. Homeowner B insulates his house, at the same cost, also saving 50 kw of capacity. Both have virtually no risk of requiring backup power. However, the utility will applaud the insulator, giving him a cheque as an incentive, but may charge the solar person a standby charge or an exit fee.

18. Many customers would say that, if they, on their side of the meter, take actions to reduce their demands on the grid, it shouldn't really matter to the distributor what actions they take. Distributors respond that they have to build a system sufficient to deliver electricity if DG is not working, but they don't need that capacity to serve load managed by CDM.

19. Both, of course, are both right and wrong. At the residential customer level, the distributor should be largely indifferent to how the customer reduces demand. The system is built on the basis of average loads for many customers in an area. It is no more of a problem for the distributor to suddenly have to provide more power for a house because their PV array goes offline, as because their kids have a wild party. In our view, at the level of the residential customer (and many small commercial customers) DG and CDM are equivalent, and should be regulated in much the same way.

20. As the size of the load variance starts to get bigger, the problem becomes more complicated. Clearly an industrial customer with a 10 MW cogeneration facility could have a significant impact on the system if the facility goes down without warning. On the other hand, distributors deal with <u>loss</u> of sizeable loads all the time, and handle it just fine, because the system has sufficient redundancy and robustness to do so. Further, the actual impact on the system will vary based on what other loads and DGs are part of that system, or that part of the system.

21. We also note that the backup power question is significantly affected by the level of reliability that the customer wants, and the level of unpredictability of the DG generation, and any correlation between the two.

22. As we note below in our discussion of standby rates, as DG becomes more ubiquitous within the Ontario system, the incremental costs of being able to deliver scheduled or emergency backup power will change dramatically. For some DG types, in our view those costs are already virtually zero (the homeowner example above), and so DG should be treated in a similar manner to CDM. As DG penetration in Ontario expands, more DG will have virtually zero backup power costs, and the types of DG that are subject to CDM-like rules should change.

23. We note in passing that we have not seen anything that suggests that TRC analysis should not apply to load displacement DG in roughly the same manner as it does to CDM. We understand that there are some differences, but in our view a more rigorous analysis of this connection would inform the Board on its policies relating to DG.

24. Another area in which the CDM analogy applies is exit fees. It is incomprehensible to us that a customer installing load displacement DG would have to pay a cost to stop using the distribution system (or part of it), while their neightbour installing extensive CDM measures would not. This issue is separate from backup power. Assuming neither requires backup power, to our mind neither should continue to pay the costs of the system that used to supply them. If either requires backup power, then that backup power should be priced separately based on the discussion above.

25. Finally, we note that utilities have recently been promoting CDM programs in the nature of demand response programs, e.g. remote control of HW heaters or AC units to allow peak shaving by the utility. Dispatchable DG facilities – particularly those with peaking capability – are very similar to these CDM programs, and it may make some sense for the rules and policies associated with those two options to be similar.

Standby Charges

26. The CDM analogy feeds into the question of standby rates and charges. It is the view of the School Energy Coalition that, subject to de minimis policies that may apply (for example, the DG=CDM examples above), standby rates and charges are almost entirely about cost allocation. Get the cost allocation right, and the standby rates flow from it. Several issues are raised by the Study and the Staff Report in this regard.

27. ***Cost Allocation Filings.*** We note that both Board Staff and EES appear to have had access to the detailed cost allocation filings of various LDCs in Ontario, and that information has informed their opinions. We also note that, as far as we are aware, that data is not publicly available. If it is or is going to be made available, then we think that stakeholders could benefit from that access in understanding the costs that may be driving standby rates. If it is not going to be made available, then in our view neither Board Staff nor their consultant should be proposing policies or rates based on that information. As SEC has said on more than one occasion in the past, rates, and policies driving rates, must be based on information that is equally available to the utilities, the stakeholders, and the decision-maker.

28. The second issue that is raised is the valuation of benefits. This has three subcomponents: where should these benefits be reflected, what is the impact being identified, and how should that impact be valued.

29. ***Benefits in Commodity or Distribution Rates.*** We believe that there is a live issue as to whether system benefits delivered by DG should be included in the calculation of distribution charges, or in the pricing of the commodity. There is little doubt, for example, that the Standard Offer price includes a component for system benefits, even though SO projects feed into the grid and their transmission or other system savings are highly variable. Thus, for those DG facilities, their system benefits are built into the commodity price they are paid. Contrast that with a farmer who uses net metering to recover the cost of onsite generation. It is arguable that there is no recognition in that "price" of the system benefits created, but alternatively it could be argued that the system benefits are "traded off" against the implicit cost of backup power, and/or the variability in power value based on time of supply. Neither of these is particularly precise, yet these are the comparisons when the Board is determining where and how to reflect the system benefits of an industrial cogen facility, for example.

30. There are, of course, many options for dealing with this, and it would be counterproductive for us to go into this in detail here. Our point is that we would like to see a wide-ranging and disciplined discussion of where and how system benefits are reflected in either commodity or distribution charges for different types of DG. To the extent that there are material differences between the "credits" being given, the Board and the government will be (perhaps

inadvertently) incenting some types of DG and not others. In our view, any differences in incentives of this type should be intentional, after a full analysis.

31. ***"Deferral" of Transmission Spending.*** That then leads to looking at issues surrounding what those benefits could be. In our view, both the Study and the Staff Report are in error in assuming that, in some cases, DG merely <u>defers</u> transmission investments. This is generally not correct (with a few rare exceptions). It is suggested that sometimes 100 MW of DG means that a tranmission line that would have been built in 2010 doesn't have to be built until 2020, but that in our view is not the right way of looking at it. The better approach, it seems to us, is to recognize that the 100 MW of DG <u>permanently</u> removes the need to build that much transmission, at least until the DG facility is itself closed down. If in fact the 2010 line still has to be built in 2020, that is because of the need to serve additional load growth. A line never has to be built to serve the load that the DG facility is serving. This different approach to transmission investments will, of course, affect how that benefit is valued. We believe that Board Staff has to go back and look at this issue again, doing some scenario modelling to confirm the long-term impacts of DG on transmission systems.

32. ***Incremental vs. Fully Allocated Calculation of Costs and Benefits.*** This leads to a related point, the difference between marginal (or incremental) and fully allocated costs (which are roughly equivalent to long-run marginal costs). This is a difficult subject, and one about which the Study appears to show some confusion.

33. In looking at the costs associated with providing scheduled or emergency backup power, it is appropriate in our view to fully allocate costs. It is not enough to say that the incremental cost of having to provide backup power is low, since most of the system will be in place anyway. If the system has to serve two purposes – planned load and backup power, for example – then costs should be allocated fairly between them. It is not correct to assume that one purpose has to be served anyway, and so the costs of the other are only the incremental costs to do so.

34. The same is true on the benefits side. Some would say that, in looking at the benefits arising out of a particular option, such as DG, it is appropriate to consider only the incremental benefits created by that option ("how much are we saving by doing this?"). This is where the confusion often arises. In the long term, those incremental benefits are in fact essentially identical to a full allocation of system costs and benefits, just as on the costs side.

35. ***DG Rates Classes.*** The different categories of DG are an important component of the analysis of standby and other DG rates. It is not clear to us that all DG facilities should be grouped into the same rate class, whether for standby purposes or any other rates. It does not appear to us that the Study, or the Staff Report, take into account the different needs of DG facilities in their recommendations, and we propose that Board Staff be asked to go back and look at this at a higher level of granularity.

36. ***Postage Stamp Rates.*** Both the Study and the Staff Report assume that scheduled and emergency backup power rates will use the same rules for every LDC, but will produce different results within each LDC based on their respective costs. This is another area in which the question of having common rates apply across the province is raised. There are

several reasons why the Board should at least consider the possibility that standby rates for some or all types of DG facilities should be fixed province-wide:

a. DG is in many ways an alternative to transmission investments, and transmission is a single rate across the province.

b. The commodity rates paid to (or enjoyed by, if load displacement or net metering) DG facilities are constant around the province.

c. The government and the Board are promoting DG because of the societal benefit delivered by expansion of DG in Ontario. Provision of standby power is, for some of those DG facilities, a cost of achieving the societal benefit, and therefore it should be shared by all customers around the province equally.

d. The societal benefit is optimized if DG facilities are sited where they are most useful, and differing cost structures of individual LDCs should not be allowed to give inappropriate siting incentives.

37. We note that, as with our comments on postage stamp rates in other contexts, School Energy Coalition has not formed a final opinion on the issue in this context either. We understand that there are arguments supporting rate differentiation based on siting, for example, where system benefits are materially different. There are many other such examples. What we would like to see, at this point, is engagement by the Board in discussion of this option.

Conclusions

38. Distributed generation may end up being one of the most important policy issues that the Board faces in the next few years, having bigger economic impacts, and more complex issues, than many of the other areas that consume a lot of the Board's resources. On the basis of the Board's DG policies and rates, billions of dollars of private sector investments will be made – or not – over the next decade. Whether those investments are made, and how, will affect the Ontario economy through the cost and reliability of electricity, and the Ontario environment through the generation technologies that end up supplying our power.

39. In these comments, we have made clear that we were disappointed in the consultant's study produced, and therefore in the recommendations of Board Staff flowing from it. This is not because those recommendations are wrong, but because it does not appear to us that a full and disciplined analysis has been done. The subject matter is too important, in our view, to skip the detailed analysis that is required.

40. Despite our negative views, we thank the Board for allowing us to provide input in this area, and hope that it is of assistance to the Board. We would appreciate having the opportunity to be involved in any future processes involving these issues.

All of which is respectfully submitted on behalf of the School Energy Coalition on the 24th day of August, 2007.

SHIBLEY RIGHTON LLP

Per: ______________________

Jay Shepherd