Shepherd Rubenstein

**BY EMAIL and RESS**

**Jay Shepherd**
jay@shepherdrubenstein.com
Direct: 416-804-2767

April 12, 2019
Our File No. 20150043

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

**Attn: Kirsten Walli, Board Secretary**

Dear Ms. Walli:

**Re: EB-2015-0043 – C/I Rate Design – SEC Submissions**

We are counsel for the School Energy Coalition. Pursuant to the Board's letter dated February 21, 2019, this constitutes SEC's submissions on the Staff Report to the Board entitled "***Rate Design for Commercial and Industrial Electricity Customers: Rates to Support an Evolving Energy Sector***" (the "Staff Report").

In these submissions, SEC first discusses some general factors affecting this consultation, then the main issues raised in the Staff Report. During the course of our analysis of the issues, our responses to the questions set out by the Board for consideration will be clear.

## A. General Matters

### 1. Goals of the Consultation

The stated goals of the Staff consultation are a) to encourage prudent adoption of new technologies, and b) to promote efficiency in distributor operations.

Neither of those appear to be true. Nothing in the Staff Report is directed at valuing the contributions of new technologies, particularly DERs. Nothing in the Staff Report is designed to ensure that distributors deploy capital and operating dollars in an efficient manner. All of the goals of the Staff Report appear to be a) to ensure that distributors are protected – in fact, kept whole - from the potential demand destruction associated with DERs, and b) to re-allocate more of the costs of the system to those customers with DERs, and less to those customers without DERs.

So, for example, the Staff Report assigns no value to DERs, only costs. In the long term, it is likely that DERs have net positive values, not net costs. By assigning only costs, the Staff Report proposes to raise another barrier to DERs, which is not in the long term interests of electricity customers.

In SEC's view, the Staff Report is a dramatic improvement on the 2016 Staff Discussion Paper, but still is a significant step away from the optimum rate design response to DERs.

The nature of the changes in the electricity sector is fundamentally about the customers requiring different services from the distributor. The market is changing, and like any business an electricity distributor must evolve its products and services to match what the market wants to buy. At one time, distributors provided firm electricity service as their (almost) sole product. As DERs become more cost-effective, particularly with storage costs coming down, more and more customers will seek to buy, not firm power, but backup or interruptible power, either on an emergency or planned basis. Both the amount customers will be willing to pay, and the costs, of those new products will be different from the old product.

What is lacking in the Staff Report is investigation into the costs (to provide) and market value of those new products. A lot of work has been done in this area throughout North America and Europe, so this wheel does not need to be reinvented. A detailed jurisdictional scan would have uncovered many jurisdictions that have delved deeply into backup power rates. Similarly, work on assessing the costs of making emergency or planned backup power available has been done elsewhere. Application of those techniques to Ontario data should be possible.

Nothing in the Staff Report attempts to establish rates or charges for non-firm power based on cost causality. While the rate designs and charges proposed attempt to make the connection between utility cost drivers and DERs, in fact no empirical work has been done, and empirical work done in other jurisdictions does not – at least, on the face of the Staff Report – appear to have been considered.

OEB Staff has done admirable work in developing its ideas beyond those set out in the 2016 Staff Discussion Paper, and in particular listening carefully to input from stakeholders from all perspectives. However, in part because of the narrow focus of OEB Staff's mandate for this project (see below), SEC is left feeling that the end result is still not hitting the mark.

## 2. Fragmented Treatment of Related Issues

In our March, 2016, submissions on the Staff Discussion Paper, SEC expressed its concerns about the timing of this consultation. The Board appeared to be tackling rate design without looking more closely at the fundamental changes to the electricity sector that were, and still are, developing. We felt then, and still feel, that when facing fundamental change in the sector, it is not obvious that your first response should be changes to rate design.

The Board has now established three new consultations aimed at tackling parts of the changes to the sector: Utility Remuneration, Responses to DERs, and Class B Global Adjustment

Allocations. The Board has also just dealt with changes to the Distribution System Code and the Transmission System Code, some of which are also directed at related issues.

This fragmented, piecemeal approach to what is a much broader challenge does not appear to us to be the optimal approach. This category of challenge is usually best met by first developing an understanding of the nature of the changes, which in this case is the changing demands on distributors (and perhaps transmitters and others) as technology evolves. Once the Board has a better understanding of the new role to be played by distributors, issues like rate design, and how shareholders make a profit, will flow from that new role. If you are selling different products, your costs and your prices and your risks will change. The structure of rates will flow from the costs and value of the products, and the structure of utility profits will flow from the nature of those products, and the risks they generate.

Before you get to those details, though, you have to have a clearer understanding of just what distributors are being asked to do. This means looking at the difference between competitive and monopoly activities, and looking at the roles of new market entrants. These are not trivial problems, by any means, but they are tractable problems.

SEC is hopeful that, as EB-2018-0287 and EB-2018-0288 get underway, they will form the basis for a broader look at the changes in the sector. That should, if the Board proceeds on that basis, result in longer term rate design and other solutions that are the result of a more comprehensive and integrated review of the issues.

In the meantime, we have approached the proposals in the Staff Report on the basis that they are, at best, interim solutions. As such, they should be assessed based on three criteria:

a) Will the solution move in the right direction to reflect the costs of the changing distributor products?

b) Is the solution designed to minimize any barriers to the positive evolution of the electricity sector?

c) Can the solution be implemented at a relatively low cost, given that in the near to medium term a new solution may have to be implemented instead?

## 3. Access to Data and Models

SEC believes that this rate design consultation should be driven primarily by empirical analysis, but we have been frustrated with the lack of accessible data to do that analysis.

This is something SEC raised in its March 2016 submissions, and to their credit OEB Staff in this process has said that they will provide access to the Board's model and data.

They tried. However, it turns out that is not really possible. There are many gigabytes of data, and the model itself (which is really just a database that can be accessed with custom-written queries) is not designed so that users other than OEB Staff can use it. Because of OEB Staff's internal resource constraints, OEB Staff cannot provide subsets or summaries of data to others, nor can they model alternative approaches to the issues proposed by stakeholders.

Again, we note that we are not being critical of OEB Staff. Having said that, the result is that issues of rate design that are fundamentally empirical in nature can only be seen through the lens of OEB Staff, only their proposed approach to the issues, and only using their tests against the available data. No other approach can or will be tested with actual data.

This is not really a good situation. If proposals are implemented on this basis, what will actually happen is that the proposals will be tested empirically, but that testing will be on actual customers after the proposals are live. We will find out whether the theoretical results expected will happen, not by full, open, and transparent testing in advance, but by a field trial across all customers in the province. That is not the right approach.

## B. Rate Design Changes

### *1. GS<50 – Shift to Demand-Based Volumetric Charges*
### *2. GS<10 – Shift to All Fixed Charge*

***Proposals.*** The Staff Report makes two proposals for the GS<50 class of general service customers. First, for those customers with a monthly peak demand of 10 kW or less, the Staff Report proposes a shift to an all fixed charge. For those customers that are 10-50 kW in demand, the Staff Report proposes switching from the current kwh-based volumetric charge to a demand-based volumetric charge, based on monthly non-coincident peak kW. The Staff Report does not propose splitting up GS<50 into two classes, presumably to save the complexity of new cost allocation rules, but would create two sub-classes within the existing class. These would be the first sub-classes in use in Ontario, as far as SEC knows.

***Problems.*** SEC is on record as being generally opposed to the all fixed charge approach to distribution rates. However, given that it has already been implemented for residential customers, and the system-related characteristics of small non-residential customers are similar to residential customers, there is merit in using some kind of all-fixed approach for these customers.

SEC does believe that charging customers based on demand rather than volume makes sense from a cost causality point of view. With the broad implementation of smart meters, this now appears to be possible. While we do not believe that a useful price signal is being sent (customer bills will still be mostly based on kwh charges for the commodity, at least), tying the charges for GS<50 more closely to the real cost driver is probably a step in the right direction.

The idea of segregating smaller GS<50 customers and larger is not new. SEC, PWU and others have proposed variations on that approach in the past. It has benefits that should be considered, but the current proposal may not be the best way of doing it.

One problem we have with the proposed approach is that OEB Staff is not proposing a proper allocation of costs between the two sub-classes. It is not, in our view, likely that the costs are identical, either on the basis of per customer or per unit of load or demand, so without cost allocation it would seem that the rates being proposed are not based on cost causality. We are concerned with this break from an important principle. If we are going to treat two groups of customers differently from a rate design point of view, it would appear to us that cost allocation is a necessary step.

Another problem we have with the Staff Report is that the two sub-classes approach creates a material change in distribution bill at the boundary, which means that classification into one or the other sub-class will matter. This will cause problems (and costs) for distributors, both on implementation and for ongoing administration.

Using the figures from Page 6 of Appendix B of the Staff Report, it appears that a customer of Hydro One (rural) would go from $$75.50 a month to $190.94 per month when they cross the 10 kW boundary, an impact of almost $1400 (153%) per year. For a customer this small, this would be a substantial cost (or saving, if the reclassification goes in the opposite direction). For a Toronto customer, they go from $64.68 per month to $125.28 per month at the boundary, an annual impact of $727 (94%). Even the lowest impact, Entegrus, is $240 (50%) per year.

SEC has attempted to model alternative approaches that might avoid this problem, but we are unable to do a meaningful job without access to a more complete data set. (We are also not able to replicate the proposed service charges and demand charges in the OEB Staff chart referred to. It would appear (without having the data) that the fixed charges for GS<10 may be lower than would be necessary, given the mean monthly demand and consumption, to be revenue neutral. However, we can't determine that without the full calculation. In any case, that wouldn't result in a material change to the boundary problem.)

***Alternative Approach.*** Conceptually, one approach would be to replace the fixed charge in GS<50 with a minimum bill equal to a similar amount (probably slightly higher, e.g. $86.62 for Hydro One rural, as opposed to $75.50). This would generate a threshold for most distributors of 4 kW to 6 kW of monthly demand, below which the minimum bill would apply. All customers would remain in the GS<50 class, and no rate classification or boundary issues would arise.

In addition to avoiding rate classification and boundary issues, this would also facilitate mitigation during a transition period. As the Board did with the full fixed charge for residential, the Board could phase in the monthly minimum, starting with the existing monthly fixed charge, and increasing over time. For most distributors, this can probably be done over one or two years, but for Toronto Hydro and Hydro One it may take longer.

On the other hand, the minimum bill approach may require material investments in billing systems. SEC believes it is likely that the billing system costs would still be much less than the two sub-classes approach, but we believe that before implementing either solution the Board should get a clear picture of distributor costs of conversion.

SEC is not in a position to actually test whether the minimum bill approach works better than the two sub-classes approach. In theory, it should be simpler, have less problems, and lower implementation costs. However, we believe that these hypotheses have to be tested before any determination is made.

SEC notes that our alternative approach is proposed because it provides affirmative or neutral answers to the three questions posed on page 3 of this letter: directionally correct, lack of barriers to industry changes, and minimizing cost to implement.

**_3. GS>50 – Capacity Reserve Charge_**
**_4. Large Users – Capacity Reserve Charge_**

***Proposals.*** With respect to GS>50, Intermediate, and Large User customers, the Staff Report does not propose any changes to basic rate design, but does propose the addition of a Capacity Reserve Charge for customers with behind-the-meter generation. The CRC would not apply to separately metered generation, but would apply to all generation that is seen by the distribution system as a reduction in load.

The theory is that, when all or part of the generating capacity is not available for any reason, the distribution system stands ready to supply the customer's full load. That is a cost to the distributor that, in fairness, should be borne by the customers that need that backup power to be available to them.

The proposals for CRC are different for GS>50 customers and Large Users.

In the former case, a charge would be applied to customers with behind-the-meter generation based on a formula, basically nameplate rating times capacity factor times class demand rate. A table of indicative capacity factors is found at page 43 of the Staff Report. For 100 kW of rooftop solar on a school, a charge equal to the GS>50 volumetric rate would be charged on 10% of that nameplate kW. In Toronto, for example, each 100 kW of rooftop solar installed by a school would cost $973 a year in increased distribution charges, and that would go up each year as Toronto Hydro increases its rates.

In the case of Large Users, the Staff Report proposes that the CRC be a negotiated figure, based essentially on the level of backup the customer wants, and the actual capacity factor of their particular generation.

***Problems.*** There are four basic problems with the CRC that applies to GS>50 customers (which includes most schools). First, it is not based on any analysis of the cost to the distributor to hold delivery capacity in reserve for these customers, whether individually or as a group. Second, it is not supported by any data showing the actual incremental demand created when behind-the-meter generation is not available. Third, it treats all behind-the-meter generation as if it is the same (excepting only capacity factor). Fourth, it levies a charge for load changes driven by generation investments, but no charge for load changes driven by changes in use, or by conservation and efficiency investments, each of which would have the same impact on the distributor.

With respect to the first problem, the Staff Report estimates the lost revenues to distributors of behind-the-meter generation, but makes no attempt to estimate the cost to provide backup power. This, is our view, seeks to answer the wrong question. OEB Staff incorrectly equates the lost revenue with the cost, as if the distributor's cost to backup 100 kW of lost generation once a year in a random forced outage is the same as the cost to serve 100 kW of demand month in and month out, mostly at peak times.

The problem here is lack of data. There is data available in other jurisdictions on costs to provide backup power at varying levels of reliability and dispatchability. Without this data, and Ontario data of similar types, the CRC proposed in the Staff Report will simply not be based on cost causality.

SEC submits that OEB Staff should implement an investigation of the costs to provide backup for behind-the-meter generation, drawing on the good work done in other jurisdictions, and also gathering local data to ensure that the external work is locally applicable.

With respect to the other three problems, SEC proposes that behind-the-meter generation be divided into two categories, based on maximum generation capacity. Generation facilities that are capable of generating up to 500 kW of output at any time should be in one category. Larger generation facilities should be in the second category.

***Alternative Approach for Generation up to 500 kW.*** Generation up to 500 kW of actual generating capacity would include most rooftop solar, and the expanding area of micro-CHP. It would not include the bulk of the CHP facilities in Ontario, many of which are used for industrial processes, or to reduce peak under the Industrial Conservation Initiative. Most of this generation would be customers in the GS>50 class, although some would be in the smaller intermediate classes.

For this class of generation, SEC believes that – at least conceptually - the distributors can be protected, and intra-class subsidies can be avoided, and the problems we have raised addressed, by changing the GS>50 volumetric rate from monthly customer peak demand, as it currently is, to the customer's rolling twelve month high demand during peak periods. This is not co-incident peak, which is not predictable for the customer, but customer peak demand during peak time of use periods.

Under this proposal, the GS>50 customer's demand each month would be the highest peak period kW demand level they have experienced in the previous twelve months. The causes of any variation in kW demand would be irrelevant. If they implement conservation measures, their peak period demand will decline, and over time so will their distribution charges. If they have a surge of business activity, requiring more kW from the system during a peak period, that will result in an increase of distribution charges. On the other hand, if they reduce production and thus peak period demand, distribution charges will decline over time. If they have behind-the-meter generation, then as long as that generation is reliably available, distribution charges will respond the same way as with conservation, i.e. when you implement, distribution charges will go down over time. However, if the generation drops off during a peak period, a new high peak period demand is created, and that remains the basis of distribution rates for the next twelve months.

The effect of this proposal would be that all decisions that impact customer demand on the distributor will be reflected exactly the same way in the distribution charges. Demand reductions in peak periods reduce distribution charges twelve months later, as long as they are sustained. (They reduce commodity costs immediately, of course.) Demand increases in peak periods increase distribution charges immediately, and continue for twelve months or until supplanted by a new peak period high demand.

The reason this protects distributors lies in the concept of demand diversity. Each time a customer, for whatever reason, puts an incremental demand on the system, they pay for that, and continue to pay for it for twelve months. Conversely, customers that do not put high demands on the system (for example, a reliable behind-the-meter generator), do not have to pay to have capacity held in reserve. In any given twelve month period, the distributor is recovering distribution costs based on the aggregate demands actually placed on the system by all customers. While in theory capacity was available for customers who did not have sudden demands (for example, they didn't have a production surge, or their behind-the-meter generator didn't have an outage during peak periods), it was not actually used for those customers during that period. That capacity was used for other customers, who did have demand peaks.

This approach recognizes the reality that the capacity needed to provide backup power is shared between those customers who might need it. If 1,000 customers each potentially need 100 kW of backup power, 100 MW of capacity reserve is not required. Only ten customers will likely need backup power at any given peak period time, so only 1 MW is required. Even if a very conservative approach is taken, 10 MW will be more than enough to serve all possible scenarios. (Customers who need backup power in off-peak periods are irrelevant, since there is ample unused capacity in the distribution system at those times.)

Of course, this SEC proposal is only theoretical. In order to consider it seriously, the Board would have to model it with real data from real customers. Actual generation patterns from a sample of behind-the-meter generation would have to be overlaid on demand patterns without behind-the-meter generation. A probability curve that reflects the impact of the generation on the peak period net load would be created, and from that could be derived the actual capacity reserve needed to meet variations in that generation. This could be stratified by type of generation, type of customer, and other factors.

SEC believes that using a twelve month rolling average peak period high demand as the billing determinant for GS >50 customers would closely approximate the real impacts of smaller DERs on demand experienced by distributors. The actual aggregate lost demand may well be small, but those generators whose demand drops off would pay extra demand charges. Over time, customers would pay those extra demand charges in proportion to the level of extra demand they place on the system. Further, customers that can manage their DER generation (for example, with storage) would be incented to flatten their demand during peak periods.

SEC therefore recommends that the Board use actual generation and demand data to model this, and other approaches to capturing variability of demand, before implementing any rate design changes for GS>50 customers, including the proposed Capacity Reserve Charge.

***Modifications of Larger Generation Proposal.*** With respect to larger generation, two realities suggest that a different approach is appropriate. First, distributors cannot rely on demand diversity to balance out the variability of demand from these DERs. Outages, for example, by big DERs will have an immediate impact on system demand. There are not enough of them to average out, as with the smaller ones. Second, the size of the installations allows customers and distributors to customize both the precise type of backup required, and the pricing of that backup. Alternatives to system backup, such as storage or backup generators, would provide cost and pricing comparisons.

Therefore, SEC submits that customers with generation in excess of 500 kW should negotiate contract rates for their backup power with their distributor, much as the Staff Report proposes.

Given the inequality of bargaining power between customers and distributors, in the event that they fail to reach agreement, they should be able to come to the Board for a rate determination.

Very few will come to the Board, given the cost, but the existence of that option would keep the negotiations balanced.

All backup power agreements, with supporting justifications, should be filed with the Board and available publicly. That way, future customer agreements will have a source of information on common industry approaches, and negotiated agreements should coalesce into a predictable range.

**Conclusion**

SEC appreciates the opportunity to provide submissions on these important issues, and hopes that our input is of assistance to the Board.

All of which is respectfully submitted.

Yours very truly,
**JAY SHEPHERD P. C.**

Jay Shepherd

cc: Wayne McNally, SEC (email)
Interested Parties