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Our File: EB20160003

Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2016-0003 – Amendments to TSC and DSC To Facilitate Regional Planning

We are counsel for the School Energy Coalition ("SEC"). Below are our comments regarding the Notice of Proposal to Amend A Code, Proposed Amendments to the Transmission System Code and the Distribution System Code to Facilitate Regional Planning (the "Notice").

The Notice and the specific proposed amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC") are very complex, and will likely lead to significant consequences that are both intended, and potentially, unintended. The nature of each individual project, the specific distributors and customers who are affected, will be unique. The Board should be very cautious and deliberate in its considerations of individual projects and applications that implement any final code amendments.

A. General Comments

The increasing complexity of funding transmission investments should, in our view, lead the Board to step back and consider whether the current system continues to be delivering on solid ratemaking principles.

Once the Board has clearly adopted the 'beneficiary pays' principle in place of the 'trigger pays' principle, the simplest funding option would have those that receive benefits from transmission investments paying for those benefits as they receive them. It is, in essence, a direct implementation of the 'outcomes' approach to ratemaking.

To do this, though, it is necessary to stop thinking about a distributor as a 'beneficiary' of a transmission investment. A distributor is an intermediary. The actual beneficiaries of a transmission investment are the customers of the distributor. It is the customers that have increased capacity to meet their needs, and increased reliability and similar benefits.

Thus, in the simplest case all transmission investments should be socialized as part of ongoing transmission rates, because if transmission planning is done correctly, all customers throughout the province will benefit roughly equally from transmission investments over time.

With that said, there are two exception..

First, transmission investments are based on forecast load. What if the load does not materialize? Right now, under the TSC the transmitter gets a capital contribution to reflect the net present value of any known shortfall in load in the future, and then gets periodic five year true-ups if the forecast is not achieved.[1] If the load is greater than the forecast, as is often the case, the transmitter put the difference in a notional account to act a credit against any amount a customer may owe at the end of each 5 year true-up. Only after the last true-up, does the transmitter credit the remaining balance on the notional account back to the customer.

The conceptually sensible approach would be to get rid of the capital contribution, and instead require all of the customers of a distributor to pay, for transmission, the revenue included in the forecast. If the actual load is too low, the unit cost to the customers would have to increase. If the actual load is higher than projected, the customers will have a lower unit cost. This is, in essence, the same as a true-up, but annually, and without the up-front payment.

That leads to the second exception. What if the load does not materialize, and there is no customer to pay the difference? This is, in practical terms, only an issue for directly connected large users. A manufacturing company may expect to be in existence for the forty-year life of new transmission assets, but sometimes that is not the case. Without some form of up-front payment, the transmitter would be left with stranded assets.

The same is not true of a distributor. Collectively, the customers of a distributor will still be around for the full life of the new transmission assets. The transmitter does not have a risk those assets will be stranded.

This makes clear that the capital contribution approach to funding is not really necessary for distributors. It is in fact an artifact of the 'trigger pays' approach, and could be scrapped without any loss of protection for the transmitter. A system that had no initial payment, and annual adjustments to transmission rates for the customers of a distributor reflecting load variations, would be full protection. Indeed, there may be a net benefit to customers, since transmitters generally can finance capital at lower rates than distributors.

Even in the case of large customers (3MW or above as proposed or some other threshold), the capital contribution approach may not be necessary. Many large businesses are users for a very long time, so a system in which their annual transmission bill is based on their load relative to forecast (or relative to dedicated costs) would produce the correct result, and save the customers some money. To protect against the possibility of the customer ceasing to be there, the customer could be required to provide prudentials, such as a letter of credit, just as distributors do to the IESO today. Actually writing a cheque up-front is not really necessary.

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[1] TSC, s. 6.5.7

SEC understands that a re-thinking of transmission investment recovery at this fundamental level has not been part of this consultation. We believe, however, that the Board should schedule this kind of more basic review in the near future, to stay ahead of the substantial changes currently taking place in the Ontario wires sector.

B. Beneficiary Pays and Allocation

Compared to the current mechanism, SEC agrees with the Board's two guiding principles for the appropriate approach to cost allocation associated with distribution and transmission connect investments – optimal infrastructure solutions and beneficiary pays. Moving towards a beneficiary pays instead of a 'trigger' pays approach is conceptually sound as it represents a fair application of normal cost allocation principles used in rate design. The concerns that arise from the Notice and the code amendments are twofold. First, the benefits that would require a customer of a transmitter to pay under the benefit pays principle are not defined. Second, the apportionment of costs between the beneficiaries under the proposed 'proportionate *benefits'* approach is really an apportionment of proportionate *costs*.

What are the Benefits? Missing from the Notice is any definition of benefits. This is important since the beneficiary pays principle is premised on the noting that the 'beneficiaries of an infrastructure investment will contribute to the cost of an investment".[2] This is important as the upfront capital cost of the investment is split between a transmitter, one or more distributors, and potentially multiple large customers of those distributors.

In the most straightforward of cases, if a distributor requires new capacity, and the proposed solution provides that capacity, they are considered beneficiaries (subject to our earlier comments), and they should pay. But if an investment undertaken by a transmitter provides for a reliability benefit to the connecting distributor, they may also be a beneficiary and also be required to also pay a portion of the capital cost through a contribution. Yet, the distributor, or more importantly, its customers may not consider the reliability benefit worth the cost. In essence, it is an unwanted benefit. It would seem contrary to the Board's principles of customer focus in the *Renewable Regulatory Framework for Electricity*[3] to be required to pay for a benefit under the TSC that they do not value.

As discussed above, the benefit of capacity is more straight forward, unless the issue is differing time horizons. Under the proposed approach, if one distributor requires additional capacity in the next 2-3 years, and a second requires additional capacity in the next 10-15 years, a new single transmission solution may be put in place that would consider both beneficiaries right away by allocating capacity to both. The second distributor, and its customers, will be required to pay now for capacity it will not need for a decade. In fact, the second distributor is further at risk since it is harder to predict load growth the farther out one goes. The load may not materialize, which may lead to additional costs to be borne by its customers through the true-up process. This does not appear fair.

Proportional Benefits Approach. Another concern SEC has is with the application of the proportional benefit approach as set out in the proposed amendments. This allocation methodology calculates the cost to serve the individual customers' needs alone, and then the costs to serve the

[2] Notice, p.3
[3] *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18 2012, p.2

networks' need alone, and then calculates the ratio of the two, and applies that ratio to determine the optimal integrated solution.[4]

The problem is that this does not actually calculate the proportional *benefits*, but the proportionate *costs.* These are not necessarily the same and especially not in the transmission context where capital investments are lumpy. For example, the step increases in transmission voltage of lines (115kv versus 230kv) do not allow for precise right sizing of a capacity need. The proportion of the single integrated solution may very easily result in a different proportion of the actual benefits between system and customer need as compared to the proportion of costs of the individual solutions. The issue is likely to be more pronounced in the allocation of customer costs amongst multiple distributors.

SEC agrees with the Board that there is a need for a Board adjudicative process to review the requests for apportionment, but it must not be limited to applying the proportionate costs of the individual solutions to the integrated solution between the network pool and connection customers. The Board should also ensure that the benefits are actually fair benefits to the connecting distributor of the proposed integrated solution. Further, the Board should ensure that the allocation methodology fairly appropriates those benefits, including in certain circumstances deviating from the proposed application of the proportionate benefits approach.

Allocation Between Larger Customers and the Distributor*.* Requiring capital contributions from large customers (3WM or greater), while not requiring it from other customers, may result in double counting. Unless the capital contribution is able to account for the revenue stream that the customer is expected to provide the distributor in distribution rates, it will be paying twice. This is because distributors will allocate some portion of the capital contribution that is being socialized among all its ratepayers to the GS>50 rate class through the normal cost allocation process. Since most distributors do not have large rate classes or ones that begin at demand greater than 3MW (GS>3000), they will be placed in the GS>50 rate class (or in some cases GS > 1000 if there is a large user class), that will include the large customers who, are also also paying the capital contribution.

If the purpose of allocating a greater amount of new or upgraded transmission connecting assets to distributors (and their customers) who benefit from them is to more fairly allocate costs amongst ratepayers, the method that underlies the proposed amendments is becoming less precise with increasing sector distributor consolidation. While a small distributor may be served by one or two connection points from a transmitter, large distributors, who serve the majority of end-use customers in the province, may be serviced with half a dozen or more, and they may be very far apart. Under the proposal, if a capital contribution is required to be paid from a small distributor with one connection point to a transmitter, it makes some sense that all the customers share in the cost, as they all benefit from it. But if a distributor has multiple connection points, spanning a large service territory, their customers do not benefit in the same way.

This problem is most accurate with Hydro One Distribution. For example, they may be required under the proposed approach to pay a capital contribution to connect for an upgrade of a

[4] Notice, p.8

transmission station outside of Kingston (which they partially serve). Yet, because the cost allocation approach is not geography based (it does deal with density), customers in northern Ontario and southwest Ontario will have to pay as well. Socializing costs within a distributor is currently the norm for distribution assets, but it is in a sense inconsistent with the intent of the beneficiary pays principle of allocating transmission connection costs downstream to the distributor and certain large customers.

Clarification is required on how this will affect large customers (3MW or greater). The Notice would appear to indicate that all large customers in a distributor's territory would have to pay[5], while the proposed DSC provisions state that only large customers who are beneficiaries and contribute to the need are required to pay based on their incremental capacity needs.[6] The latter would avoid the situation of where a mine in Northern Ontario paying for an upgrade of capacity to serve a new manufacturing facility in southwest Ontario, both of which are served by Hydro One.

C. <u>Replacement of End-of-Life Distribution Connection Assets</u>

In the Notice, the Board recognizes that where a customer's load has materially declined, it would expect a transmitter to apply its judgment and replace an end-of-life asset with a new connection asset that meets the lower forecast need.[7] Yet, the Board has decided not to include a code requirement to 'right-size' to a lower capacity. SEC believes the Board should not just include a provision to make clear that a lower capacity replacement connection is a potential outcome, but the expected outcome. Transmitters have a financial incentive to replace an end of life asset with at least a like-for-like asset, and not a smaller and less expensive option. The higher the value of the replacement, the larger the rate base on which it earns a return.

Since most individual end of life asset replacements are themselves not large enough to meet the materiality threshold, there will likely be no opportunity for review these for prudence. But these individual asset replacement choices add up over time. Requiring in the TSC that a transmitter must right-size will help protect the interest of customers.

Bill Impact Mitigation Options

The Notice has identified that distributors may not be implementing the 'optimal' transmission connection solution because the current cost current cost arrangement incentivizes, non-optimal investments.[8] One of the reasons is that there are significant cost implications and bill impacts due to the lumpy nature of these usually large capital investments that may require large capital contributions from individual distributors.[9] The Board has proposed three alternative funding alternatives to mitigate these concerns. SEC has a number of concerns with the proposal, but it is important to note, none of them truly address all the issue which was originally raised in the SECTR proceeding which in part led to this consultation.

In the SECTR proceeding (EB-2013-0421), a concern arose that one problem in moving from a trigger pays to beneficiary pays principle is that a distributor may find themselves being required to

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[5] Notice, p.10
[6] Proposed DSC Provision 3.2.4A
[7] Notice, p.12
[8] Notice, p,17
[9] *Ibid*

pay a large capital contribution for a transmission solution which in their view may not be have required or a distributor may not value the benefits (i.e. reliability) when weighed against the cost. In a trigger pays model, the distributor is in control and simply can choose not to make the investment themselves. In a beneficiary pays model, they may lose some of that control and be required to pay the transmitter a large capital contribution. In the SECTR case this would have represented capital contributions equal to, for one distributor (ELK Energy Inc.), over 100% of the value of its rate base.[10]

Besides the obvious cash flow problem this creates for a distributor, the impact of those costs being added to rate base would lead to very material rate impacts. In the SECTR proceeding, ELK (as part of the E3 Coalition) provided evidence that the proposed Hydro One transmission project would have resulted in a capital contribution that would alone have led to a 5.88% distribution bill impact for an average residential customer.[11] Both the annual instalment payment option and the upstream connection adder option, simply smoothed out the impact over a number of years (either before or after it goes in service). Neither does anything about the overall increase. The real benefit to the installment proposal is it may help distributors with their cash flow concerns. It does not benefit consumers with respect to rate recovery of the capital contribution paid to the transmitter

Advanced Funding Approaches. SEC is opposed to both the advanced funding proposals, as they lead to customers paying before the assets go into service. To do so would be a marked departure from the Board's fundamental ratemaking approach, which requires assets to be used or useful, before their impact is includes in rates.[12] The advance funding proposals would lead to unjust and unreasonable rates. The two examples that the Notice cite where similar approaches have been taken are not comparable. Both smart meters and investments for renewable connections were done as a result of the need for quick implementation of government policy. In the smart meters case this was due to the promulgation of Reg. 233/08, O. Reg. 235/08, O. Reg. 234/08) and for renewable connections, the passing of the *Green Energy Act.*

Both proposed advanced funding options create significant intergenerational equity issues. Customers are being required to pay for assets that will not be in-service for years. The Notice and DSC code amendments do not provide any guidance on how long before the asset is forecast to go in-service, will either advanced payment options be in place. Footnote 16 of the Notice claims that it "typically takes two years for a line connection and three years for a transformation station from confirmation of the need for the new asset to the date construction is complete and goes into service".[13] SEC is not sure the basis of those numbers, but experience shows that it takes longer, and especially transformer stations are often delayed. This is especially true when they are to service an incremental load, that itself often gets delayed. Often a distributor may base incremental load needs on subdivision and commercial development information that comes from the municipality they service. Experience shows that municipalities are very optimistic on the level and timing of developments in their community. Rightly, transmitters and distributors delay work that would be required to serve them.

[10] EB-2013-0421, E3, Notice of Intervention and Cost Eligibility Request, November 26 2014, p.3
[11] EB-2013-0421, Evidence of E3 Coalition, p.7, Table 1
[12] For example, see *Partial Decision and Order* (EB-2012-0064 - Toronto Hydro-Electric System Ltd), April 2 2013, p.13
[13] Notice, p.20, Footnote 16

In some cases the projected load never materializes, and the work does not actually occur. The advanced funding options may then have customers paying for assets up to 5 years in advance, and in some cases for capital work that may ultimately never be built In the latter case, distributors would presumably be refunding the amounts like any other deferral account credit, on a prospective basis. This leads to intergenerational equity issues.

The upstream capacity payment approach is probably the most egregious. Under this approach, only new customers are paying a per kW payment for some <u>future</u> identified expansion. It is not clear why these new customers are any different from existing customers and so should be required to pay. Yet, those future customers who are driving the need for the transmission expansion will not be charged the per kW capacity payment. This seems contrary to the beneficiary pays principle.

Implementation. The Notice provides that the distributor is given the option to implement any of the three mitigation options, as well as the current status quo option (i.e. single lump sum payment), to allow it needed flexibility.[14] SEC submits that while distributors should be given the option to *propose* use of any of the three mitigation options, they should not be implemented without Board approval. For a distributor, they are held whole with each option. It is their customers who are paying on a flow-through basis. As the Notice points out, depending on the situation, different funding methods will more or less be cost-effective. [15] The distributor has incentive to choose the option that benefits they distributor, not its customers. The selected option must require testing in a hearing by customers, and approval by the Board.

D. <u>Bypass Compensation</u>

The Notice proposes that the bypass compensation provision be added to the DSC to align it more with what is provided under the TSC. SEC provides a number of comments.

Notice and DSC Amendments Are Different. The actual DSC provisions do not appear to mirror the intent of the Notice. The proposed sections 3.5.1(a) and (b) appears to apply only when a large customer (3MW or greater) fully disconnects from the distribution system and the distributor no longer receives any rate revenues from its connection assets.[16] In contrast, the Notice appears to indicate that as customers are now becoming more active, they are reducing their use of the distribution system which may strand assets that were put in place to serve them.[17] Yet the DSC amendments, as SEC reads them, would require a large customer not just to reduce their use of the system, but fully disconnect. This cannot be the intent of the provision, and would not be consistent with the method of calculating the bypass compensation. Further, it is also inconsistent with the

[14] Notice, p.23-24
[15] Notice, p.23
[16] Proposed DSC Provision 3.5.1:

> A distributor shall require bypass compensation from a customer, with a non-coincident peak demand that meets or exceeds 3 MW, if:
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> (a) the customer disconnects its facility from the distributor's distribution system and subsequently connects that facility to a generation facility or to the facilities of any customer such that both the load facility and a generation facility are connected to the distributor's distribution system on that customer's side of the connection point; and
>
> (b) the distributor will no longer receive rate revenues in relation to that distribution asset

[17] Notice, p.32

bypass provisions of the TSC (both current and proposed). SEC submits, at the very least, the current DSC language for bypass compensation is very unclear.

Exemptions. The Board is proposing that not all load reducing measures undertaken by a large customer (3MW or greater) will trigger bypass compensation to be paid to a distributor.[18] The proposed amendments to the DSC state that no bypass is payable when load reduction (withdraws from the distribution system) are obtained from embedded renewable generation, energy conservation, energy efficiency, or load management activities. No rationale has been provided for why said embedded renewable generation is exempt but no other forms of embedded generation.

SEC is concerned with how the bypass provision would interact with the proposals that have been discussed between Board Staff and stakeholders in regards to the Board's ongoing consultation on Commercial/Industrial Rate Design (EB-2015-0043). In a meeting with stakeholders, Board Staff proposed a capacity reserve charge concept. Under the proposal, customers with embedded generation would be charged a rate equal to the nameplate capacity of its embedded generation facility. This would act as a type of standby rate reflecting the cost of ensuring the distribution facilities are available if needed. Under the proposed DSC bypass compensation provisions, a customer who installs behind the meter (non-renewable) generation is required both to pay bypass compensation and capacity reserve charge. Either it should be charged the lump sum bypass compensation to reflect that it is stranding assets, or it should pay the ongoing capacity reserve charge to reflect the cost of those same stranded assets it may use. It cannot be required to pay both.

The proposal to require bypass compensation for changes in load caused by behind the meter generation is also entirely inconsistent with Ontario government policy. The IESO's Industrial Conservation Initiative ("ICI") program, which has recently been expanded, is aimed at incenting customers to reduce their peak demand, which benefits the entire system.[19] One of the most common ways for large customers to do this is by investing in behind the meter generation (i.e. combined cycle facilities). The current bypass proposal would create a strong barrier to adoption, as it would create a large upfront penalty to these customers who are required to pay bypass compensation. The proposal would also stymie innovation in storage technologies which customers may deploy to reduce their peak demand behind the meter. Under the current proposed amendments, storage would not be considered under any of the exemptions. Large customers who deploy storage may be required to pay bypass compensation upfront, which would likely make such investments uneconomical.

SEC believes that the Board should reconsider the view taken in the Notice[20] that a separate consultation is not needed for the issue of bypass compensation. The issue is complex. and raises specific policy issues relating to fundamental changes that are occurring, with customers increasingly being active energy participants. It is also not clear why only large customers (3MW or greater) should be liable for bypass compensation. Other larger customers have the same ability to strand assets, which would currently have to be paid for by all other customers.

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[18] Notice, p.33
[19] See http://www.ieso.ca/sector-participants/settlements/global-adjustment-class-a-eligibility
[20] Notice, p.32

The Board should initiate a separate consultation, or consider adding the issue to its current Commercial and Industrial Rate Design consultation (EB-2016-0004) which is already grappling with some of the same conceptual issues.

Yours very truly,
Shepherd Rubenstein P.C.

Original signed by

Mark Rubenstein

cc: Wayne McNally, SEC (by email)
Interested parties (by email)