Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Attn: Ms. K. Walli
Board Secretary

September 20, 2018

Dear Ms. Walli:

Re: EB-2016-0003 – Revised Proposed Amendments to the Transmission System Code and the Distribution System Code to Facilitate Regional Planning

The Electricity Distributors Association (EDA) is writing to provide comments in the above-named matter. They are set out in this Covering Letter and the Attachment thereto.

Regional Planning is a demanding task that has far reaching implications. The key objective of regional planning is to ensure ongoing customer access to a system that can safely and reliably deliver power and energy to them. Cost Allocation for Regional Planning is the process that quantifies an accurate and appropriate price signal in a timely manner, suitable for the needs of many parties such as decision makers, investors, consumers, government planners and prospective supply chain participants. Under the existing "trigger" pays rules some Regional Planning costs are socialized because they were included in the Transmitter's Network Pool while others were recovered from certain identifiable parties. The proposed amendments are intended to replace the principle of "trigger" pays with the "beneficiary" pays.

These amendments operationalize the "beneficiary pays" principle. The tangible outcomes are expected to be:

- An increase in the "beneficiaries" who will be responsible for a greater proportion of the costs (and by implication a lowering of the proportion that will be recovered through Network Transmission Charges); and
- An increase in the eligible beneficiaries charge parameters.

While these outcomes result in a lower level of socialized cost responsibility they also increase the charge parameters used to assign cost responsibility for the non-socialized costs and,

Electricity Distributors Association
3700 Steeles Ave. W., Suite 1100, Vaughan, Ontario L4L 8K8 Tel/Fax 647.EDA.5300 1.877.262.8593 email@eda-on.ca www.eda-on.ca

implicitly, mitigates rate shock. If this is indeed the OEB's driver it may, or may not, align with the industry's need for policies that will put all parties on a balanced playing field.

The Independent Electricity System Operator's Market Renewal Program (MRP) has been underway since November 2016. The EDA notes that the MRP is expected to impact the need for incremental transmission and/or distribution infrastructure as well as the configuration of existing infrastructure. The EDA suggests that the OEB consider co-ordinating the proposed "Coming into Force" of any Code amendments focused on the Cost Allocation of Regional Planning with the MRP's timelines.

LDCs have a long track record of making investment decisions so that customers can have ongoing access to distribution services at a fair price. They invest to be able to accommodate new supply points (e.g., to provide feeders downstream of transmission stations or transmission connections), to address reliability (e.g., to network feeders rather than rely on radial infrastructure), to attach new customers.

LDCs expect to apply fair policies and fair rules that will result in fair outcomes for the affected stakeholders in the majority of cases. EDA members have reviewed the Board's proposed code amendments through this lens for consistency with existing regulatory policy and for an underlying Framework. LDCs note that the OEB's adoption of the 5MW threshold, versus the 3MW previously proposed, aligns with LDCs rate class structure. Our members look forward to a framework suitable for allocating costs to either emerging technologies or innovative connection configurations, and that can be confidently applied to scenarios other than those scoped in the proposed code amendments, as this was not discernable in the proposed code amendments. The EDA observes that the Board has provided special cases (e.g., End-of-Life scenarios) and that at least two of the special cases (newly attaching >5MW loads, two LDCs connecting to the same transmission infrastructure) occur so infrequently that it does not appear to be appropriate to codify them.

The EDA believes that the proposed code amendments must be "fit for purpose". The Board has articulated that it expects similar customers to experience similar outcomes. The EDA has some reservations as to why the Board has focused on achieving similar outcomes for similar customers. The Board's legislated mandate is silent on this expectation. The legislation is consistent with achieving the principal objective of economic regulation, which is setting just and reasonable rates. The EDA notes that each LDC has its unique service area, unique cost structure, and specific system constraints such that the best realization of this objective appears to be that the rules will be applied consistently and that differences between LDCs will be data driven.

Further, LDCs are concerned that it is foreseeable that the proposed amendments will result in similar customers of an individual LDC experiencing differing outcomes depending on where in the service area they choose to site their facility or the state of the distribution infrastructure. Consider the example of a large load (e.g., a server farm, a marijuana greenhouse operator, a large car park with charging infrastructure for hundreds of electric vehicles) that seeks to attach to the same LDC and is evaluating 3 different locations that will be referred to as A, B and C:

- If location A is a "green field" site the customer can expect to pay a financial contribution based on their load and the infrastructure costs, where the customer has no ability to control the infrastructure costs.
- If location B is in an area where the existing distribution infrastructure has not attained its end-of-life the customer may still be required to remit a financial contribution to support the LDCs investment in appropriately sized infrastructure as well as to remit bypass compensation because the existing, otherwise under sized infrastructure has not attained its End-of-Life. In this situation, not only will the customer have no ability to control the infrastructure costs they will also have no ability to control the quantum of the bypass charge as it is rooted in decisions made by the LDC in a prior period.
- If location C has distribution infrastructure that is inadequate to serve the projected load then the customer will be expected to remit a different amount of financial contribution to support the LDC's investment in appropriately sized infrastructure. Again, the amount to be remitted will depend on decisions made by the LDC in prior periods and where the newly attaching load customer has no ability to control the costs of the newly expanded/enhanced distribution infrastructure.

The above analysis raises a concern that the proposed amendments may not result in stable or predictable outcomes for the customer.

The EDA repeats a submission made in November 2017 on the need for worked examples (EB-2016-0003, EDA comments, Attachment A, page 4). The EDA seeks worked examples of the anticipated application of the proposed code amendments so that LDCs know they are applying the rules correctly, so that customers will know that the LDC is transparently abiding by the rules and so that all parties are equally informed of the expected outcomes. These worked examples can also be used to test whether the OEB's objectives will be achieved and may foreshadow the impact to today's customers, specifically for whether advantages they enjoy today will persist. As was also observed in the November 2017 comments, unlike transmitters LDCs engage in Regional Planning issues and considerations infrequently (EB-2016-0003, EDA comments, Attachment A, page 4). The EDA seeks provisions that will place LDCs on equal footing versus the transmitter - provisions that will provide LDCs with the ability to access appropriately skilled and experienced individuals who can readily evaluate the proposed regional plan and the associated allocation of costs. This is expected to support all parties understanding and to prepare the LDC to respond to their customer’s enquiries in the future.

LDCs note the OEB’s focus on beneficiaries and seek to better understand its scope so that they correctly operationalize the term. For example, is “beneficiary” synonymous with “user”? does “beneficiary” refer to parties who will experience indirect benefits or will connect in the future? Distribution systems are not static, and neither are the parties they serve. Orienting the analysis on beneficiaries is expected to address any concerns of benefits being obtained by free riders. The proposed “Coming Into Force” provision contemplates that the OEB will apply rules consistent with the beneficiary pays principle on a go forward basis - except for the Supply to Essex County Transmission Reinforcement (SECTR). The EDA notes that the key decisions on the SECTR project were made using the existing rules that are not based on beneficiaries. However, its costs are to be allocated using the eventual 2018 cost allocation rules. This contrasts with the treatment of all other projects that were either committed to or that were entered into service before the contemplated “Coming Into Force” date. The Board is also proposing additional powers to deem some customers to be beneficiaries of regional planning investments and to evaluate some of the outcomes of regional planning using proxy cost data. The EDA suggests that the Board adjudicate projects that rely on or are informed by the use of proxy data or that could result in impacts to deemed customers so that LDCs appropriately operationalize these concepts. The EDA proposes that the Board either not codify provisions that use deemed customers or proxy data or that it defers the “Coming Into Force” of these provisions.

The EDA anticipates that operationalizing the proposed amendments related to Bill Impact Mitigation will be difficult. LDCs understand that the effect of the installment option is to smooth the bill impact to consumers and thereby avoid undue rate shock. LDCs are unclear as to whether the mitigation is intended to result in predictable bill impacts to specific line items, whether it is to mitigate the “lumpiness” of significant capital investments over time, or whether it is intended to constrain bill increases below a threshold value. If the intention is to achieve predictable bills then there is a follow on issue of inter-generational inequities that should be explicitly contemplated and addressed. If, however, the intention is to mitigate “lumpiness” there may be cross subsidies between customer classes. LDCs acknowledge that good rate making requires that these cross subsidies not be so high as to be considered undue. LDCs also expressed that there is a risk of an unintended and undesirable consequence of this provision with respect to debt management and borrowing capacity. LDCs point out that a situation could emerge where an LDC may be off-side of the Board’s hypothetical capital structure through the combined effect of material non-discretionary distribution system relocations and the operation of the Annual Installment Option. The EDA expects that the Board will be open to considering such a situation, should it be realized.

The EDA observes that stranded debt is a significant and emerging issue and suggest that it is better dealt with through a dedicated and focused issue specific proceeding. It is undesirable to simply import a provision from another regulatory instrument. LDCs recognize that while it is helpful to understand the Board's thinking on the recovery of bypass compensation, it is not robustly rooted in an analysis of the fundamental underlying issue of stranded debt and stranded costs. LDCs need clear regulatory policy so that they can responsibly manage their resources and be able to provide service on an ongoing basis. Customers need a clear policy that demonstrates how the Board will maintain a financially viable industry that supports its fulfillment of one of its legislated objectives and delivers a key outcome of economic regulation.

The counter case to bypass compensation is asset overloading. LDCs monitor their distribution systems and gather data to discern which assets have been overloaded, the magnitude and duration of the overloading and so on. They use this data in combination with other data and resourcing considerations to manage their portfolio of assets. Overloading is not a clear-cut sign of poor asset management, rather it is an indicator that further probing is necessary. At the extreme, overloading can degrade an asset's ability to serve for its intended life or when operated at design parameters. It is important to incorporate the inherent flexibility of the infrastructure when assessing overloading. LDCs acknowledge that chronic overloading over successive periods that is not recognized is inappropriate and may be unacceptable. LDCs note that the evidence filed in the SECTR proceeding included a chart of the chronic and persistent overloading of Hydro One's Kingsville TS that has existed since the 1990's. LDCs acknowledge that there are rate making tools available that can address the drivers of overloading (e.g., curtailable rates, interruptible rates) and policy alternatives (e.g., conservation, deployment of Distributed Energy Resources). There are administrative tools also, such as financial penalties, technical audits, more frequent and more intrusive reporting requirements. The EDA recognizes that customers and the OEB expect LDCs to be good asset managers, and that all these stakeholders expect the transmitter to also be a good asset manager. Because there is a range of circumstances that give rise to overloading and a range of responses, the EDA believes the proposed rules on overloading may be premature. Instead, LDCs suggest that the OEB adjudicate an application on planned investments intended to address overloading.

The proposed code amendments raise practical implementation questions such as:

- changes to distribution rates to align with the proposed revisions to Basic Connection infrastructure;
- clarification of implications for ownership and ongoing maintenance obligations of Basic Connection infrastructure;
- revisions to all LDCs Conditions of Service.

Our members seek regulatory accounting guidance from the Board on issues such as:

- the appropriate treatment of bypass compensation;
- the methodology to use to compute and record the impact to the Net Book Value of the bypassed infrastructure if the assets are accounted for on a pooled basis;
- recording contributions charged to one entity and remitted by another; and
- how to account for bypass compensation if the affected asset is to be used to provide distribution service in a future period.

As the Board is well aware, all LDCs are engaged in the provision of a public good at commercial conditions and terms. One of the outcomes of the OEB's Renewed Regulatory Framework is a sharpened focus on customer interests. LDCs have in the past and will continue to respond to all customers interests - including those of local area governments, whether they desire to create economic growth to benefit their inhabitants (e.g., employment in for-profit firms) or to provide essential public services such as health care.

The EDA seeks OEB clarification on the appropriate implementation of the OEB's proposed "Coming into Force" provisions from the perspective of fairness. The EDA recognizes that the projects that have either been initiated or completed since the SECTR project will be caught by the existing rules. It appears that only SECTR, by virtue of the OEB authorized deferral account, could experience a different outcome. This different outcome is not a forgone conclusion. The EDA recognizes that the key decisions leading up to the design and construction of the SECTR project were made under the existing rules and that there is a principal-based argument in favour of applying those rules. If the Board were to proceed in this manner it would have the flexibility to potentially socialize such costs by authorizing their recovery through Transmission – Network charges, or, that it could phase the recovery in over time to address concerns of rate shock.

Whatever Code amendments the OEB authorizes, it will result in some parties understanding that they have, in prior periods, underpaid while others will understand that they have overpaid. It is advisable to identify and prepare for the effects of this transparency at the earliest opportunity.

Essex Powerlines, Entegrus Powerlines and ELK Energy are the three LDCs engaged in the SECTR proceeding that gave rise to the proposed code amendments. As stated earlier, the EDA raises the question of the fairness and appropriateness of applying the proposed code amendments to the SECTR project and that it will create out of chronological sequence differences. The EDA contends that, with the passage of time, their specific concerns will be recognized as generic concerns. Since the OEB adjourned the SECTR proceeding for an indefinite period these three

LDCs have lacked clear and objective data and their ability to responsibly invest capital and to respond to questions from their customers has been hindered. The OEB's timely adjudication of the costs of SECTR will provide the decisions, clarification and direction that they – and the industry – need. If the OEB declines to adjudicate on SECTR by hearing final submissions or re-opening the evidentiary portion of the proceeding it risks leaving the E3 LDCs in an uncertain situation as to the next steps including how to administer the discovery of new data and the available forms of recourse. It also raises questions about the appropriate consumer protection for the LDC when it is a consumer being served by a transmitter.

From the customer's perspective it appears that the industry and the regulator have not progressed from the situation as it existed in 2015. This is an unfortunate outcome. Furthermore, with the passage of time new investment needs have emerged. The Board needs to take steps to deal with specific investments and to simultaneously provide rules and policies. Customers need all this and expect no less.

Please refer any questions or comments to Kathi Farmer, the EDA's Senior Regulatory Affairs Advisor at kfarmer@eda-on.ca or at 905.265.5333.

Sincerely

J. Rangoon

Justin Rangooni
Vice President, Policy & Government Affairs

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