November 6, 2017

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Re: Proposed Amendments to the Transmission System Code and the Distribution System Code to Facilitate Regional Planning Board File No. EB-2016-0003

Dear Ms. Walli:

On September 21, 2017, the Ontario Energy Board gave notice under section 70.2 of the Ontario Energy Board Act, 1998 of proposed amendments to the Transmission System Code (TSC) and the Distribution System Code (DSC).

Attached please find AMPCO's comments on the proposed amendments.

Please do not hesitate to contact me if you have any questions or require further information.

Sincerely,

(ORIGINAL SIGNED BY)

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Proposed Amendments to the Transmission System Code and the Distribution System Code
EB-2016-0003 Comments
AMPCO's Comments

General:

AMPCO's comments contained herein are focussed on the assignment of cost to load customers for increased transmission connection service capacity. The sections dealing with assignment of cost to generators and with replacement of connection assets at end of life are not discussed.

Much of the discussion in the report is based on a proposal by Hydro One and the IESO, which had its genesis in the SECTR project. This project seems to provide a useful example as it encompasses many possible issues to consider in developing the cost allocation policy, so AMPCO will continue to use it in its submissions as a reference case.

At the core of this report and the ensuing draft code changes is a stated principle called "beneficiary pays". While there may be alternative approaches that could be applied, the principle itself is not the Issue, but rather how it is being defined and applied.

The report itself does not directly attempt to define a beneficiary or to establish criteria to establish a beneficiary.

Merriam Webster defines a beneficiary as *"a person or thing that receives help or an advantage from something"*, which seems workable for this discussion. The corollary would seem to be that someone or something that does not receive a benefit or advantage cannot be said to be a beneficiary.

The code changes do appear to implicitly define beneficiaries as triggering customers or generators. Since distributors are customers in this case, they are assigned capital contribution responsibilities. The process proposed in the report also requires that some specific customers of the distributor be assigned individual portions of the capital contribution requirement, namely, customers with non-coincident peak demand greater than 3MW (new proposed definition of large customer) and embedded distributors. All other customers of the distributor are to be bunched together and share the remaining cost of the capital contribution through rates.

The effective definition of beneficiaries defined in the report and the proposed capital contribution process is, then, all customers serviced by the connection asset, directly or through a distributor and all other ratepayers of distributors served by the connection asset.

In this implied definition:

- A "Large" customer whose load is not growing and may even be shrinking is viewed as a beneficiary.
- Residential customers who are served by an affected distributor are defined as beneficiaries, even if their load is not growing.

- Customers of a distributor in a portion of its service area that are not served upstream by the connection asset are viewed as beneficiaries. Unless the Board and Hydro One are proposing to set different Hydro One residential rates across the province as connection assets are upgraded, it is hard to see how this outcome is avoided.
- It would appear that "large" customers of distributors that are not served by the upstream connection asset are also viewed as beneficiaries, although it is unclear how this might apply to Hydro One distribution networks, which has the largest number of large distribution supplied customers across the province.

The stated intent of the OEB application of the "beneficiary pays" principle is to avoid socialization of costs to non-benefiting parties. Unfortunately, the result of the implied definition of a beneficiary is that the portion of the cost of the connection asset not covered by future revenues will still get socialized, only across a smaller group of non-benefiting customers.

The five-year term maximum also potentially creates an inter-generational equity problem. Once the distributor has fully met its obligations under the capital contribution requirement, it will have no additional future cost associated with the upgrade (subject to annual true-up, which acts on the distributor as an incentive at seek new customer load). Presumably, the distributor could recover some of the contribution from new customers when they appear, although it is unclear if they would be forced to. Given the general desire to attract customers that any business has, it is difficult to see a connection surcharge related to the paid-off capital contribution being applied to new loads. Yet, it is these new loads that will in fact be the beneficiaries of the connection investment.

A similar issue will arise with small loads that increase demand after the capital contribution is paid off. Essentially, a hot tub installed by a residential customer six years after the in-service date could be seen here as a free rider.

There is another geographic or regional unfairness that occurs as a consequence of this proposal. Customers in large metropolitan areas such as the GTA, where growth is slow but measurable, will seldom see the effect of a capital contribution requirement. This is because Ontario's grid system is inherently designed to meet the needs of the GTA and other large urban areas, where the capacity of a new 115kv or 230kV circuit is often absorbed by revenue growth within the CCRA period. If the GTA were much smaller, the available increments of capacity (standard engineering options) would also be smaller; such as one sees in lower population density regions outside Ontario, where smaller transformer station sizes and lower transmission voltages are the norm. Effectively, the SECTR project could be seen as overly expensive not because transmission capacity increments are necessarily as lumpy as they are, but because Hydro One and the IESO are wedded to large standard capacity increments, because this arrangement works well in most of Ontario.

Taken as a whole, the impact of the proposed application of the "beneficiary pays" principle is that distribution customers in smaller centres that will not benefit from a massive increase in capacity will be forced to pay for much of it, simply because of the accident of their location and the distributor serving them, while some true beneficiaries will not. A secondary and problematic consequence of the proposed process is that, by forcing much higher costs of growth on customers and industries in regions where population and economic density is lower, it acts as another inhibition to provincial development and growth outside urban areas. This runs in direct opposition to the “postage stamp” philosophy regarding energy cost in Ontario and uniform transmission rates across the province.

Finally, there is another, fundamental problem associated with the proposed methodology. From a customer perspective (including distributors in this case), the connection asset should only be paid for once, with the transmitter being responsible for maintaining and enhancing it as time goes on. This is the case with distributors themselves; when their feeder loads reach capacity, they increase capacity to meet, the generally growing load without going back to customers for more contributions (unless specific additional capacity requests are made).

Related to the problem noted in the previous paragraph, it should be noted that, when additional capacity is built, such as in the SECTR case, it usually follows several years when the transmitter has been receiving higher than average connection charge revenue from the existing assets. Likely, the existing line connection and transformation asset costs in the SECTR study have been over-recovered for several years, with no credit to the customer “beneficiaries”. In short, the revenue benefits from fully loaded facilities are being socialized across the connection pool, while this proposal will localize the costs of new under-loaded assets.

As an alternative to the proposal, The Board may wish to consider more general socialization of at least some of the connection pool costs that arise when “lumpy” investments are required. One option might be to simply set a minimum (average) capacity increase charge for all new customers and any demand billed customers wanting to increase their load, and then use this to fund connection pool shortages. Direct connected non-distributor transmission customers could continue under the existing regulations.

Specific Comments

New definition of “Large” Customer:

From AMPCO’s perspective, there is no logical reason apparent for treating distribution customers 3MW and larger as discreet customers requiring different treatment than any other customer. All customers of an LDC pay for the LDC assets through rates, whether those assets are booked capital contributions or any other asset. The OEB proposal also does not seem to indicate whether or not the distributor’s cost allocation process must ensure that these large customers do not pay twice for the capital contribution, once directly up front and once again through the distributor’s rate setting process.

The capital contribution process generally was designed to ensure that costs were recovered from customers requesting new or enhanced connection service. Creating a new definition of a large customer in this instance would seem to be simply a mechanism to reduce the immediate capital contribution obligation on the distributor, even where the customer is not driving the expansion requirement.

Because capital contribution requirements for private companies are calculated on a shorter time period (5 – 15 yrs.), the burden of capital contributions will fall proportionately heavier on private business than on distributors and the period during which credits may be assigned will also be shorter. This will be true even if the private business receives no real benefit at all. Also, the report does not suggest how the annual CCRA revenue recovery true up process should be managed when a mixed forecast period with mixed loads is involved. For example, if a large customer of a distributor increases its load above forecast while the other customers of the distributor reduces load below forecast, does the large customer gain a credit while the distributor serving it pays a true up penalty?

Also there is an issue of fairness that comes into play between customers that are just above or below the 3 MW threshold. The treatment of a 2.9 MW customer will be very different than a 3.1 MW customer.

Non-coincident Peak Demand Criterion

The use of non-coincident peak demand in DSC 3.2.27 as it applies to large customers and distributors is technically inappropriate and unfair. Large customers typically have peak demands that are non-coincident with the demand of the rest of the distributor's customer base and thus contribute less to the distributor's total demand at peak than their maximum demand would suggest. The use of non-coincident peak demand in the capital contribution calculation thus effectively inserts a cross-subsidy into the calculation. It is the customer's contribution to coincident peak demand on the expanded facility that should be used as the basis for determining proportionate responsibility.

Lack of "Right Size" Incentives

Related to the above, the report suggests on page 12 that a transmitter should be expected to "right size" capacity as load declines and facilities reach EOL. However, specific direction from the OEB is avoided, making the likelihood of change about zero, especially given that the regulatory incentive for the transmitter is to oversize (i.e., increase rate base), not right-size capacity.

ORTAC Requirements

In the SECTR documentation, reference to the IESO ORTAC requirement is made several times, seemingly suggesting that the need to meet these requirements constitutes a "benefit" that applies to all customers serviced by the project, presumably making all these customers fit the definition of a beneficiary. ORTAC is essentially a set of IESO reliability and restoration criteria.

A very similar set of criteria are established in the TSC as delivery point reliability criteria. These were developed specifically to address the reality that not all transmission customers receive the same level of service reliability and availability. The TSC delivery point reliability criteria are only used as indicators, with very limited obligations on the transmitter to spend relatively small amounts to identify and correct deficiencies. If a substantial investment is required to remediate the reliability problem, this investment is to be made only at the option and expense of the affected customer. Thus, it would seem inappropriate if the ORTAC criteria were taken as justification to force an additional cost on customers that are not requesting improved reliability.

Advance Funding Options

The OEB proposes two new approaches (Upstream Capacity Payment and Upstream Connection Adder) that would both provide distributors with a pool of funds before the new or upgraded connection investment goes into service in order to reduce the amount the distributor would need to borrow to finance the capital investment.

AMPCO does not support options that provide advanced funding to distributors to reduce their borrowing requirement for two reasons. Firstly, AMPCO has always endorsed the principle that customers should not be required to pay in advance before an investment goes into service and essentially borrow funds before the distributor; and secondly the cost of borrowing for the distributor is significantly less than the cost of borrowing for customers. In AMPCO's view, requiring customers to pay in advance of the date the capital contribution is due to the transmitter is not appropriate or in the best interest of customers.

Bypass Compensation

The OEB is proposing to identify circumstances in the DSC where bypass compensation should be required and how it will be determined noting embedded renewable generation, energy conservation, energy efficiency or load management activities (e.g., net metering) does not trigger bypass compensation. The OEB is proposing that the 3 MW threshold apply in relation to bypass compensation. The OEB is of the view that a separate consultation process on bypass compensation is not required.

Currently the OEB has a consultation looking at rate design for Commercial and Industrial Customers (EB-2015-0043) where recent thinking shared by Board Staff with some stakeholders reflects a new rate design proposal that includes a capacity reserve charge whereby customers with behind the meter generation would be charged a "standby rate" rate based on the nameplate capacity of the generation facility to allow use of the distribution system when needed. It is unclear how the proposed bypass compensation in the DSC would interface with the rate design proposal and in AMPCO's view the two may be at cross purposes and there may be unintended consequences for customers that deserves further analysis. Under the two proposals a customer that has non-renewable generation would be required to pay both bypass compensation and a capacity reserve charge; two charges that independently and combined negatively impact the business case for behind the meter generation. It is unclear to AMPCO how energy storage would be treated and impacted under bypass compensation and the capacity reserve charge proposals. AMPCO submits the full extent of the impact between the two proposals on customers is not known and requires further clarification.

For the reasons discussed above, AMPCO submits the issue is complex and further consultation on bypass compensation and commercial and industrial rate design is required.