December 2, 2010

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

Dear Ms. Walli:

Re: Review of Electricity Cost Allocation Policy
Submission of AMPCO Comments
Board File No. EB-2010-0219

In accordance with the Board's letter dated September 2, 2010 regarding the above proceeding, attached please find AMPCO's written comments on the options and recommendations contained in the Elenchus Research Associates Report.

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

Sincerely yours,

(ORIGINAL SIGNED BY)

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AMPCO Comments
Review of Electricity Cost Allocation Policy
OEB File: EB-2010-0219

General Comments

AMPCO welcomes this interim review of the Board's cost allocation policy. It has now been three years since the Board's report and some progress has been made in addressing the issue of inter-class subsidies raised in EB-2007-0667.

AMPCO submitted several questions to Elenchus Research Associates (ERA) prior to the stakeholder session, and all were specifically addressed, within the limited scope of the review report. The response to AMPCO's questions as well as those of others did however reveal a shortcoming of the review. Namely, the scope of the ERA report was fundamentally a high level review of the policy approach and not one that was significantly enlightened by data and experience gathered from the past three years of cost allocation filings, COS applications and other OEB initiatives. Moreover, trends in other jurisdictions were not reviewed as part of the review.

These limitations on the review significantly constrain the outcome of the review and its ability to provide useful guidance going forward.

It is reasonable to expect that cost allocation can be further improved once smart metering data are available. At the same time, this should not preclude making improvements now, based on the significant body of information that has accumulated since LDCs were required to file cost allocation analysis with their COS applications, as well as the data acquired by the Board through research in other areas.

There is also the matter that, while smart meter data will begin to become more generally available in 2011, it will be some time before enough data has accumulated to produce a reliable body of information to inform policy development. To our knowledge, serious work on the development of analytical tools and skills for this end has yet to begin, which will mean a further lag between smart meter implementation and full leveraging of the potential information benefit. In another policy initiative of the Board, the review of Distribution System Reliability Standards (EB-2010-0249), stakeholders were cautioned that it will be years before useful smart meter data has accumulated to the point that it can support improved standards and measurement. Progress on cost allocation should not be delayed on the basis that smart meter data is needed. Moreover, most of the issues discussed in this review (e.g., embedded generation, microFIT, R/C band for streetlights and GS>50) will not be better informed by smart meter data.

One general issue that arose repeatedly during the stakeholder session was that of the scope of the review with respect to rate design versus cost allocation. It was noted several times that this process is one of cost allocation review and not one of rate design. While respecting the general desire to keep the two issues separate, it has to be acknowledged that this is an artificial separation. Issues of cost allocation invariably give rise to questions of whether the underlying cause of an apparent allocation issue is one of rate design or customer classification. These three aspects of rate structure are inherently interdependent, so we submit that the Board should not be overly restrictive in scope for this review.

In Ontario, there are now only a handful of customer classes for distribution service. The Board is understandably reluctant to increase the number of classes significantly, as this could make regulation a more difficult task. At the same time, the Board should recognize that, as the types of service required increase with the advent of microFIT, embedded generation and other developments, these changes need to somehow be accommodated. Service charges and modified cost allocation can only go so far and attempting to contain these new requirements in the existing classes may make it more difficult to manage as time goes on. The Board should consider relaxing the current resistance to new customer classes and allow some new classes where this would engender better cost allocation and analysis.

As an Association representing a relatively small number of Ontario consumers, AMPCO is aware that the overall impact of cost allocation on its members is a relatively modest portion of total distributor charges. The amounts in question may seem modest in comparison to other issues facing the Board. From the perspective of individual business customers, however, cost allocation can have a significant impact on the success and sustainability of their business.

The following specific comments are not limited to matters of direct interest only to AMPCO members. AMPCO's perspective is that a fair and accurate cost allocation system is of ultimate benefit to all customers. Hence, we have offered comments on most of the topics in the ERA report.

Specific Comments

MicroFIT Rate Class

ERA has proposed continuance with a microFIT charge versus establishment of a separate MicroFIT class, for the time being. ERA also recommends that each distributor be allowed to set its own rate, reflecting cost causality for the distributor and also perhaps some uniqueness in the local microFIT population.

The stakeholder discussion revealed significant differences in treatment of microFIT customers. For example, one utility places all microFIT accounts into the GS<50 class.

AMPCO supports the recommendation to allow distributors to set their own MicroFIT service charge specifically, as this is likely the best way to discover the actual cost of serving these customers.

Moreover, this should be taken further, to allow distributors to modify the billing weight for microFIT. ERA resisted this on the grounds that it could unfairly assign "transitional" costs to microFIT.

There are several problems with this approach. Transitional costs are real costs and by not allocating them properly, the true cost of microFIT in an LDC will not be known and will be subsidised by other customers of the particular LDC. Burying such costs in the LDC's overall billing cost will not support having them addressed and reduced over time. How much of the cost difference is transitional due to technical issues versus how much is in fact related to basic differences between microFIT and residential billing service will be difficult to discover if real costs are not used to set the weighting factor.

AMPCO members have had similar experience with weighting factors, where businesses in different service areas receive widely different fixed charges, which relate in turn to different weighting factors. While businesses would definitely prefer that high billing costs be reduced, they do accept these differences and live with them until they can be mitigated. There is no obvious reason why microFIT customers could not show similar forbearance.

Allocation of Costs to Load Displacement Generation

ERA recommends using default avoided costs and benefits to establish standby charges for load displacement generation above 500kW. AMPCO disagrees with this approach for two reasons. First, it will inevitably prove unfair to some customers with generation and perhaps also to distributors in some cases. Second, default values can act as a disincentive to developing load displacement generation that constitutes a "highest and best use" of energy resources. These points are discussed below:

1. Fairness

Load displacement generation of 500kW or greater will normally cost in excess of $1,000,000. This is a significant cost for any business and the developer deserves the full benefit of its investment. On page 38 of its report, ERA states that "When the customer owned generation is not available, generally due to an outage, the customer is supplied by the distributor for all its electricity needs". This assertion seems to assume that the customer's standby requirement would equal the output rating of the generator and that the standby charge would be based on the need for the distributor to provide "full" standby power at feeder peak. In short, ERA's assertion leads to a "worst case" standby charge, calculated without regard for the actual configuration of the customer's facilities and operating characteristics. In the previous Board process on cost allocation, distributors did state that their determination of standby charge was based on exactly this type of approach.

AMPCO asked ERA whether in fact it had done any research that supported the blanket statement on page 38. The answer was no.

It would be unfair to a customer if, in developing a generation project that actually reduced cost for the distributor, it still had to pay for distribution service as though the generation did not exist. There are several types of generation configuration and operation that can in fact require less standby service than the rating of the generator. A couple of examples:

- Where the generator produces both process heat and electricity, with the manufacturing process dependent on the process heat output of the generator (e.g., combined heat and power, or CHP). In these configurations, loss of generation diminishes the overall manufacturing process, which will then consume less total electrical energy than it did when the generator was on line.
- Where the customer has designed the generator such that it will provide a very high degree of reliability during working (peak) hours. Maintenance based outages are scheduled outside of production hours, with the intent of ensuring a very high degree of reliability/availability during peak/working hours, so that standby power is not needed when it would be most expensive for the customer to buy and the utility to deliver. A variation on this scenario is to schedule major maintenance in shoulder seasons when HOEP is lower and demand on the distribution system is

also lowest. Gas turbine generation has developed an excellent record for availability when it can be maintained regularly in times of low demand.

2. Policy Alignment

Policy in Ontario is to encourage, distributed generation, which is what load displacement generation definitely is. Customer-owned generation that provides process heat also fits the definition of combined heat and power (CHP), which encouragement is an objective of Ontario's long term energy plan. (Ontario's Long Term Energy Plan, pages 34-35).

If blanket formulas are applied to calculating standby charges for load displacement generation in general, the result will be that, for some of the best projects, the inability to realize the benefits of reduced demand on the distribution system will diminish the business.

AMPCO recommends that, for load displacement projects for which the customer believes it will not require full standby capacity, there should be a mechanism for review, consultation and reduction of the standby charge if appropriate. This could be as simple as a joint review by the distributor and the customer (or customer's consultant) of standby requirements. This mechanism would require the Board's consent that negotiated standby charges are acceptable, where a defined process has been followed.

Again, the flexibility described above may seem onerous from the perspective of the distributor. From the view of the customer, however, with a million dollar investment under consideration, this is a logical and fair approach. It is also one that would better incent projects benefiting both the customer and the distributor.

Allocation of Miscellaneous Revenues

The recommendation to allocate miscellaneous revenue to customer classes in the same manner as corresponding costs is both fair and transparent. Further, including these revenues in the revenue/cost ratio calculation by customer class is the correct approach. AMPCO supports the ERA recommendations on this issue.

Unmetered Scattered Load

The matter of how best to allocate costs for USL has been a significant issue for the Board for several years. The issue is aggravated by calculated R/C ratios for some USLs that seem to suggest this class is being significantly subsidised and by concerns of the CATV may be over-charged for service in some instances.

There were a number of issues raised in the stakeholder session that were essentially definitional; e.g., whether a "daisy chain" was one connection or several and what the relationship between account, customer and connection should be.

Whether or not ERA's recommendation for a separate sheet with default values will resolve the matter is difficult to say. At minimum, it should provide more information on the costs associated with USLs in general.

The root problem and solution may lie not in cost allocation but in customer classification. USLs are clearly distinct from other customer types in their load patterns and use of distributor services. Placing them in a general service category and then attempting to reach an appropriate cost allocation by adjusting different weighting factors may not be the best approach. Moreover, differences in load characteristics, connection arrangements and service requirements may justify separate classes for streetlights/sentinel lights and CATV.

The board may wish to consider establishing a separate class or classes for USLs, with class definitions and guidance on matters such as consumption limits for unmetered connections, bill aggregation, etc.)

Weighting Factors for Services and Billing Costs

Across Ontario's LDCs, AMPCO's members experience a wide variety of weighting factors for billing and services. These are reflected in fixed customer charges. For example, the fixed monthly customer charge in the >5000kW class in Toronto is $2,874, whereas in Horizon's service area it is $11,152.88. To say the least, it is difficult to understand how two LDCs in the same geographic area and each with relatively modern capabilities for billing and service provision could exhibit such a wide difference in costs.

The use of default weighting factors and a separate sheet as recommended by ERA may help to reduce the spread among distributors to a more credible range. At the same time, distributors should have recourse to substitute actual values where their cost is materially different than the default option. The Board should, however, require cost-based justification for departure from the default values, with more exceptional departures requiring more detailed justification.

Departure from default weights should not be allowed simply on the basis of local policy preference. Where a distributor requests an unusual departure from the default weight, it should also outline the cause of the departure and how it plans to bring any exceptional costs under control in the future.

Transformer Ownership Allowance (TOA)

The ERA recommendation to calculate TOA only for those classes containing some customers providing their own transformation is a step in the right direction, but additional guidance should be provided. Distributors should be required to track the costs of transformation specific to these classes (typically GS>50KW and above), which are different than for the residential and GS<50kW classes.

The TOA is another issue that has vexed cost allocation efforts over the years, and remains contentious. As with other persistent issues, it may indicate a deeper issue. In this case, the existence of a TOA reflects the fact that transformer ownership is a customer choice (i.e., a competitive, non-monopoly transaction), whereas cost allocation is a process for rate setting in monopoly services.

The simplest way to resolve the difficulty is to remove transformation service from the cost allocation process for those customers that may optionally choose to own their transformation. Where ownership is a customer choice, the distributor (or others) could offer a transformation service. Cost allocation for transformation need not apply and a TOA would be unnecessary. If the distributor transformation service rate was seen by the customer or others as unreasonable, the market could correct the problem.

Opening the market in this way would be similar to what has happened with line extensions and secondary service.

Allocation of Host Distributor Costs to Embedded Distributors

ERA recommends a threshold test to establish separate charges for embedded distributors. This seems reasonable and appropriate, as do the suggested criteria. Since Hydro One is the dominant host distributor, the effect of the 500kW threshold should be determined before implementation.

One of the questions in the stakeholder session related to costs that perhaps should not be allocated to embedded distributors, such as CDM, bad debt, etc. ERA has stated it has not researched this matter. To avoid pancaking of charges, the board should review the cost allocation model to ensure that all allocated costs are appropriate to embedded distributors.

Since Hydro One is the dominant host distributor and has a specific ST class with similar threshold criteria to those suggested by ERA, the Board should consider allowing Hydro One to continue classifying embedded distributors as ST-class, perhaps with modifiers to avoid rate pancaking as noted above.

Revenue to Cost Ratio Ranges

When the 2007 cost allocation process completed, existing ranges were based on a rationale that was at least partly statistical. Ranges were based on observed distributions of existing R/C ratios among distributors, with the objective to narrow the ranges over time, as additional data became available.

It would therefore seem logical that an improvement (narrowing) of the existing ranges at this time would be based on a review of what has been learned through numerous cost of service filings and other Board initiatives over the past three years. Unfortunately, the scope of the ERA review does not appear to have allowed for such supporting analyses. Rather, ERA has settled on recommending modest changes to the streetlight and GS>50kW class over the next three or four years.

The most problematic recommendation is to retain the asymmetric band for the GS>50kw class, while reducing maximum R/C to 1.40. In the original process initiative, there was some plausible justification for asymmetric bands, based on statistical evidence. With the recommendation to make the sentinel light band symmetric, that all bands would be symmetric except for the GS>50 class. Statistically, it is not plausible that one band could be asymmetric while all others in the cost allocation pool are not.

Also, one of the major sources of variation in R/C ratios among LDCs was related to different ways of calculating the effect of the transformer ownership allowance. This has now been standardized, so the statistical spread that may have justified a broad range should not longer apply.

While precise numbers are not available for the GS>50 class, it appears that all GS customers account for slightly over 20% of distributor revenue. Since this includes GS<50kW as well as intermediate and large user classes, it is likely that GS>50 customers account for 10% or less of total distributor revenue. This suggests that a 3-4 yr transition for this class (same as suggested by ERA for streetlights) to a maximum R/C of 1.20 is not likely to have a significant impact on other customer classes.

AMPCO submits that, as a principle of fairness, it is time to move the GS>50kw class to an R/C range equal to other classes, of .80-1.20, with a 3-4 year transition period.

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