Association of Major Power Customers of BC (AMPC)

BC Hydro Application for a Certificate of Public Convenience and Necessity for the Dawson Creek and Area Transmission Line (DCAT), Project No: 3698640

Response to Information Request No.1 of BC Old Age Pensioners' Organization (BCOAPO)

June 14, 2012

1.0 Topic: AMPC
Reference: Exhibit C-3-10, pages 4-9

Preamble: The first response in Section 3.1 describes the postage stamp rate principle as rates that do not differ by location or vintage of customer. The subsequent questions deal specifically with the issue of customer contributions for new transmission infrastructure and why they are necessary in the context of postage stamp rates that are designed to recover the fully allocated cost of service.

1.1 Do the same issues exist with respect to the cost of new generation that will be required to serve new customers seeking service from BC Hydro in that the typically higher cost of this new generation will be rolled-in with the lower depreciated cost of existing facilities?

Response:

No. The same contribution policy issues do not exist with respect to generation, which is normally excluded from consideration.

For utilities offering postage stamp rates, the cost of new generation is not included in the calculation of customer contributions ***except*** *where local generation may be deployed as an alternative to, or substitute for transmission additions otherwise required to serve the new customer*(s). BC Hydro is the only utility that AMPC is aware of that has proposed burdening new customers with the incremental costs of the common generation system.

An example of how the local generation exception may work in practice follows from the recent government policy decision that natural gas-fired generation supporting LNG plants is “clean”. Apart from its flexibility to deal with uncertain load forecasts and load persistence, subsequent local gas-fired generation would avoid the higher costs of transmission reinforcements as proposed for DCAT, and potential additional lines to Kitimat or the Peace River region. An appropriate tariff would allow the recovery of a significant portion of the local gas-fired generation costs through customer contributions and limit the upward impact on postage stamp rates, without resorting to special “off-tariff” negotiations for each major resource development.

1.2 If not, why not?

Response:

All utilities determine their generation requirements to meet the aggregate system load regardless of individual customer vintage, location or size. There are sound theoretical and practical reasons for the complete roll-in of new generation costs and avoidance of contributions or special tariff negotiations. Typically a utility will roll-in higher cost new generation with lower cost (depreciated) older generation whenever new generation, such as new IPP purchases, are required to meet increases in the aggregate system demand, or to replace generation at end of life, such as the refurbishments recently approved for the Ruskin dam and under consideration for the John Hart facility.

In his classic text "*The Economics of Regulation: Principles and Institutions*" Alfred E. Kahn addresses at length the problems of defining marginal costs and applying them to ratemaking where a large proportion of the costs are common, and why existing customers are considered as responsible as new customers for increments of common generation costs.[1]

The electric system functions as a continuum, with generators connected (topologically) at one end and new customers at the other. The generator side is the most "collective", and the customer's dedicated substation is the least collective. Cost causation at the customer connection end of an electric system is therefore always the sole responsibility of the new customer and conversely, cost causation at the generator end is always the collective responsibility of every customer in aggregate. Cost causation at intermediate parts of the transmission network will fall between these two extremes.

Professor Kahn describes how the existing customer who maintains their load in the forecast period (and does not reduce it by, e.g., one MW) is just as responsible for increments of generation costs as the customer who brings a new load (e.g., for one MW).[2] According to this rationale, there is no theoretical basis for discriminating between old and new customers based on the costs of generation. Nor is any "subsidy" created when the new customer enjoys a rolled-in rate that is less than the cost of new generation. This discrepancy is common to all electric utilities with postage stamp rates, and is addressed in BC through stepped rate structures for all rate classes that send a marginal cost consumption signal to every customer, regardless of whether the customer is large, small, old or new.

More practically, tariff contribution mechanisms that take into account the incremental cost of generation will likely fail in practice due to the

[1] Alfred E. Kahn, "*The Economics of Regulation: Principles and Institutions*", (Massachusetts Institute of Technology, 1988), Volume 1, part 1, pp. 70-87.
[2] This rationale also forms the basis for treating DSM as a substitute for new generation, e.g., the expression "NegaWatts".

impossibility of establishing precise cost causation linkages, extreme instability based on order of arrival, and the associated risk of regulatory or legal challenge. For example, the timing of load forecasts, offsetting conservation initiatives, and the magnitude and timing of major generator or system reinforcements all present significant challenges to this type of tariff being reliably applied from a mechanical perspective (to say nothing of issues arising from changes in energy policy).

As new generators often result in large incremental increases ("lumpy" additions) with uncertain timing (for instance Site C) and are built to meet aggregate rather than individual loads, it cannot be established which sufficient certainty which customer tips the balance or exactly when this would happen. There will always be unresolved issues over the exact margins required, how much "surplus" exists at what time, who is "backing up" whom, and who should pay for surplus or remedial increments once the collective approach to generation is abandoned.

The expected development of LNG plants on the North Coast provides an illustrative example of the practical difficulties with a tariff that seeks to capture customer contributions for incremental generation capacity. According to BC Hydro's IRP, BC Hydro currently maintains sufficient generation to serve two LNG customers: the Douglas Channel and Kitimat LNG (Apache) projects. The third LNG project, presumably Shell and partners, however, represents the generation capacity of Site C. The Apache project arguably has no incremental generation cost and the Shell project would have a massive incremental cost.

TS #6 would seek to recover these common generation costs (theoretically $0 and Site C's approximately $8 billion), in order of appearance because each load exceeds 150 M.VA, resulting in very different tariff treatment for similar projects - but fairness and customer acceptance can only be met by similar treatment. The situation is compounded by considering that the circumstances could be reversed if the timing and phasing of either project were to shift.

Assignments of the common costs of generation in this manner could not be sustained and would be successfully challenged on both pragmatic and theoretical grounds. Developers facing zero contributions would likely proceed with electric service at the expense of all existing customers. Developers facing billion dollar contributions would likely take their revenue and royalty producing projects elsewhere.

Transmission costs (or local generation that displaces transmission) are less collective as they serve customers in a well defined area and are fairly and appropriately assigned through a contribution policy that is designed to function under high growth conditions.

1.3 If yes, should similar customer contribution requirements/principles be applied to the incremental generation costs triggered by "new" customers?

Response:

See response to 1.2.

2.0 Reference: Exhibit C-3-10, page 8, lines 26-31

2.1 Please outline the basis/sources supporting the 20% rough rule of thumb referenced in the Evidence.

Response:

The 80/20 "rule of thumb" has been considered a contribution policy guideline by a number of utilities and commissions over the years, notably in Alberta. A relatively recent decision of the Alberta Energy and Utilities Board (now the Alberta Utilities Commission) suggests that this rule was relied on too heavily in previous years, resulting in setting the revenue multiplier too high.[3] Multiplier "creep" is a phenomenon where the utility is over-rewarded from an increased ratebase following repeated roll-ins. The EUB instead established a reduced revenue multiplier of 1.15. In addition to the issue of an appropriate multiplier level, the decision reinforces the need to review tariffs, including contribution policy mechanics and revenue multipliers regularly and especially when significant changes to growth rates are expected.

3.0 Reference: Exhibit C-3-10, page 9, Footnote #2

3.1 Please outline the basis/sources supporting the 2-3 year revenue multiplier as being the industry norm.

Response:

Mr. Stout relied upon his familiarity with tariff design, derived in part from contribution policy comparisons undertaken in his role of developing transmission tariffs for Alberta Power (since split into ATCO Power and ATCO Electric) and the AESO in the 1990s and early 2000s. Both of the Alberta Power and AESO tariffs were designed to accommodate the "boom and bust" cycles of oil and gas development, and operate effectively in times of system expansion as well as dormancy.

Alberta now uses a multiplier of 1.15 of transmission revenue for transmission extensions.[4] Saskatchewan Power uses a general revenue multiplier of 2 for smaller services and a less generous discounted cash flow (DCF) analysis for "radial" extensions serving loads greater than 2,000 KVA.[5]

[3] EUB Decision 2007-106, p. 93.
[4] Ibid.
[5] SaskPower Electric Service Business Policy - EP 2.0.

4.0 Reference: Exhibit C-3-10, page 3, lines 7-14 and page 13, lines 8-13

4.1 Is the main reason for the different capital contribution outcomes between DCAT and NTL due to the fact that a higher portion of NTL costs are associated with Transmission Connection and therefore 100% the responsibility of the customers with no associated offset allowance? If not, what is the reason?

Response:

AMPC and Mr. Stout are unaware of the proportion of NTL Transmission Connection costs relative to the rest of NTL costs, as these are subject to negotiation outside of existing tariff provisions.

The larger issue, however, is the definition of Transmission Connection cost categories in the first place. By treating extensive radial additions as entirely "connection", they are ineligible for any roll-in treatment, whereas non-radial additions are eligible for an unusually large offset allowance. AMPC is not aware of any other utility that does not also allow customers served by radial extensions to benefit from the available roll-in allowance.

5.0 Reference: Exhibit C-3-10, Appendix A

5.1 Please confirm that including transmission connection in the costs subject to the "sharing formula" would reduce the contribution required from customers (per bullets 1 – 3 and 5).

Response:

The classification of transmission elements proposed by AMPC would render the radial transmission additions of NTL (with the exception of individual substation costs) eligible for the *reduced* roll-in allowance also suggested by AMPC. This would reduce the contributions expected from NTL customers as TS #6 offers no roll-in allowance for this radial development despite representing significant future revenues for BC Hydro. It would also remove the need for departures from the published tariff and controversial negotiations at this and subsequent developments.

5.2 Please confirm that using a revenue multiplier of between 2 and 3 would tend to increase the amount of contribution required from customers.

Response:

Confirmed. AMPC's proposal would also cause some customers to be assessed a contribution where they would not otherwise face one under TS #6. Please note, however, that contributions could cause some DCAT customers to prefer natural gas drives or self-generation, potentially resulting in a smaller DCAT scope, revised timing and lower resulting costs to BC Hydro.

5.3 What principles should be used in establishing the value of the "revenue multiplier"?

Response:

There are two schools of thought on how to establish the quantum of a contribution policy revenue multiplier.

One approach is to conceptually simplify the system as a static network with a new radial connection and then perform a DCF or net present value (NPV) comparison of the lifetime cost of the theoretical "connection" with the expected lifetime revenues at regulated rates.[6] This method emphasizes the theoretical contribution price signal in selecting a societally efficient outcome, implicitly assuming no impact on the broader system and that a high degree of precision in contribution calculations is important.

In Mr. Stout's view this method is acceptable for distribution level considerations but is too static and narrowly defined for use in transmission tariffs. The DCF/NPV method relies on a number of simplifying assumptions that are unrealistic for transmission planning under high growth scenarios:

- a static and non-lumpy transmission network without "looped" reinforcements;
- radial extension costs continuously variable to the nearest kilometre; and
- that customers' alternative locations or alternative energy sources are similarly variable.

The DCF/NPV method concentrates on the new customer price signal to the exclusion of the primary purpose of a contribution policy, which is not to facilitate perfect retail competition, but to limit excessive general rate increases and maintain the universal applicability of averaged postage stamp rates.

The DCF/NPV "accounting" method has the advantage of being readily quantifiable (though this should not be confused with useful accuracy) and is reasonable for use in determining utility "investment" on behalf of smaller new customers such as residential or commercial services that invariably involve small radial "taps" and do not precipitate major transmission additions. The DCF/NPV approach is a useful consideration for a Commission charged with regulating competition between gas and electric utilities for smaller distribution level customers. This method fails to satisfy its more fundamental purpose however, when applied to transmission extensions involving significant increments of growth.

AMPC prefers a "planning-based approach," with recognition that it is more important for a contribution policy to shield customers from excessive rate increases and provide stability by treating all new

[6] E.g., this approach is discussed in Ex. A2-2, the 1996 "Utility Extension Test Guidelines" recently posted by Commission Staff.

customers with fairness and predictability, than it is to achieve precise and linear contribution “price signals”.

The planning-based approach requires public transparency and consistency in planning to meet forecast loads. Under this approach parties and the regulator are provided with estimates of likely electric system configurations, rate effects and potential revenue multipliers over at least a five-year future timeframe, as well as access to historical contribution calculations. The potential revenue multipliers and resulting customer contribution levels are “reverse engineered” from the starting point of ensuring future rate stability. This allows parties to estimate the effectiveness of the contribution policy using forecast and historical data. The approach was successfully used in Alberta to maintain stable postage stamp rates while accommodating the vicissitudes of oil and gas development cycles.

This approach does not allow precise linear price signals for individual extensions, but doing so is not necessary. Customers never truly have contiguous and smoothly variable alternatives, but rather binary decisions between local or distant resources, or between one fuel type or another. The reasonable existence or absence of a contribution, even if imprecise, is the most important result of a contribution policy and is necessary to guide an economic and orderly choice of development. An effective contribution policy provides more certainty for new and existing customers and obviates the need for ad-hoc “off-tariff” negotiations and attendant uncertainty that tend to stall economic development.