FINAL ARGUMENT ON BEHALF OF

THE CLEAN ENERGY ASSOCIATION OF BRITISH COLUMBIA

Re: BRITISH COLUMBIA HYDRO and POWER AUTHORITY

Fleet Electrification Rate Application

Project No. 1599032

January 10, 2020

BC HYDRO Fleet Electrification Rate Application

Final Argument of CEABC

I. EXECUTIVE SUMMARY

The Clean Energy Association of B.C. ("CEABC") supports BC Hydro's Fleet Electrification Application ("Application") and offers some suggestions how this rate proposal or similar proposals may be improved in the future to encourage even more electrification.

The principle points that CEABC makes in this submission are:

A. The Context – BC Hydro should play the leading role in the wide scale electrification of British Columbia's energy.

B. Policy Goals and Key Rate Design Criteria.

C. BC Hydro's proposed Rates are definitely a step in the right direction, in that they recognize that the Demand Charge is the most critical obstacle to new electrification customers.

D. The Demand Transition Rate is also a step in the right direction, in that it relieves any potential electrification customers from the high cost of the Demand Charge in the early years when they would experience the lowest load factors.

E. BC Hydro should investigate the potential for using large-scale batteries and "smart" charging, as a means of avoiding the need to expand capacities.

F. Economic evaluations of the proposed Fleet Electrification Rates.

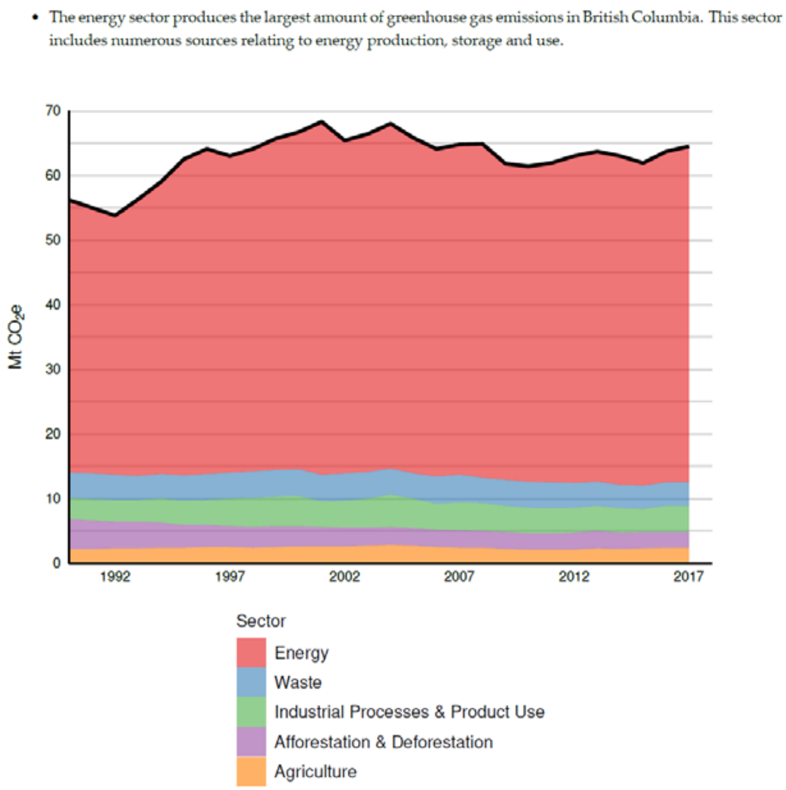
G. The cost of new capacity is a highly conjectural assumption.

II. GENERAL COMMENTARY.

A. The Context – BC Hydro should play the leading role in the wide scale electrification of British Columbia's energy.

In its Application, BC Hydro ("BC Hydro", "Hydro" or "BCH") points out that "Road Transportation" was responsible for roughly 17 million tonnes per year ("Mtpa") of CO2e, *"which represents 27% of the total greenhouse gas emissions in B.C."*[1]

The 2017 provincial inventory[2] gives the updated figure for the total provincial GHG emissions at about 64.5 Mtpa, of which 17.5 Mtpa is allocated to "Road Transportation." The provincial inventory also points out that the vast majority (81%) of B.C.'s emissions are due to the energy sector -- the production, storage, and use of energy.[3]



This revelation emphasizes that the majority of the required emission reductions can only be achieved by replacing fossil fuel energy with clean, non-emitting electrical energy as fully and rapidly as possible. Clearly, to accomplish such an extensive electrification, BC Hydro should play the leading role.

---

[1] Exhibit B-1, Application, page

[2] Available at https://www2.gov.bc.ca/gov/content/environment/climate-change/data/provincial-inventory

[3] http://www.env.gov.bc.ca/soe/indicators/sustainability/print_ver/envreportbc_ghg_emissions_Sep2019.pdf

The electrification of the two bus fleets that are the focal point of this Application, TransLink and BC Transit (each with about 1500 potential electric buses), will be a significant step forward, but it is only a very small step towards achieving the provincial goal of a 40% reduction by 2030.

Of the 64.5 Mtpa of total provincial emissions, the BC Transit fleet reported 64,323 tonnes of GHG emissions in 2017 – i.e. approximately 1/1000th of the total provincial emissions. The TransLink fleet is approximately the same size. Together, if both of these two fleets (the largest in the province) were completely electrified tomorrow, the inventory of provincial emissions would only be reduced by 0.2%. Somehow, a 40% reduction has to be achieved in the next 10 years, and most of this achievement will rely on BC Hydro's ability to electrify the load.

The underlying objective of this Application is to encourage, and to incentivise, a rapid shift from fossil fuel burning to electrical power for the largest diesel bus fleets in the province. Converting these bus fleets is an essential step in the electrification of British Columbia. But there is much to do beyond these bus fleets. Of the heavy duty diesel vehicles, bus fleets are the easiest conversion prospects. Long-haul trucks will be much more difficult, if only because they don't return to the same depot for daily recharging.

The next best source for GHG reductions in the Road Transportation sector will most likely be the light and heavy duty gasoline trucks, and the gasoline cars. Of the 17.5 Mtpa emitted by Road Transportation vehicles, these two categories emit 63% (7.1 and 3.9 Mtpa respectively)[4].

However, BC Hydro will be very challenged to encourage the electrification of those vehicle segments. BC Hydro has already expressed concern that the fleet rate options in this Application cannot be applied to charging facilities for third-parties:[5]

> *"…stakeholder feedback with regard to this Application indicated a desire to expand the availability of the proposed services, and rates, to customers that provide charging services to third-parties. In BC Hydro's view expanding the availability of the proposed services to that customer segment would materially reduce the likelihood that ratepayers would benefit from them and thus undermine their lawfulness."*

It remains to be seen what creative solutions BC Hydro will come up with to electrify those other vehicle segments, but out of necessity, BC Hydro must accomplish that electrification if British Columbia is to meet its GHG reduction goals.

---

[4] From the Provincial GHG inventory table located at the previous citation
[5] Exhibit B-1, Application, page 13

B. Policy Goals and Key Rate Design Criteria

BC Hydro states that the new rates in the Application, namely the Overnight Rate and the Demand Transition Rate ("Rates" or "Fleet Electrification Rates"), are specifically intended *"...to support the electrification of fleet vehicles and vessels in BC Hydro's service territory."*[6]

It further states, under Policy Goals:[7]

> *"In November 2018, British Columbia's Climate Change Accountability Act was passed and sets legislated targets of a 40 per cent reduction in carbon emissions from 2007 levels by 2030, a 60 per cent reduction from 2007 levels by 2040, and an 80 per cent reduction in emissions by 2050. On December 5, 2018, the B.C. Government released its CleanBC plan (**CleanBC**) aimed at reducing greenhouse gas emissions in British Columbia. The plan identifies further efforts in cleaner public transportation as an action to help the reduction of greenhouse gases. Included in the B.C Government's Mandate letter to BC Hydro dated February 21, 2019, is a request that BC Hydro ensure that its operations align with the B.C Government's new climate plan."*

BC Hydro has adopted the Government's Policy Goals and is seeking to reduce B.C.'s greenhouse gas emissions by electrifying some of the fossil fuelled transportation sector.

In the Application, BC Hydro broadly groups its Rate Design Criteria,[8] and in its Workshop slides[9] these are described as the "Key Rate Design Criteria":

> *"1. Economic Efficiency – price signals that encourage efficient use and discourage inefficient use;*
>
> *2. Fairness – fair apportionment of costs among customers, no undue discrimination;*
>
> *3. Practicality - customer understanding and acceptance, practical and cost effective to implement; and*
>
> *4. Stability – revenue and rate stability."*

The above criteria are a summary grouping of the Bonbright Rate Design Criteria against which BC Hydro subsequently evaluates each of the new Rates. However, the Policy Goals have been overlooked or forgotten from this list of Key Criteria.

---

[6] Exhibit B-1, Application, page 2
[7] Ibid. page 5
[8] Ibid. page 14
[9] Ibid. Appendix G, slide 18 of 57

The Bonbright Rate Design Criteria should not be the sole determinatives when the implementation of provincial Policy Criteria is the underlying objective.

The effectiveness of the Rates in achieving the Policy Criteria should be the first order of priority. The other criteria, such as cost efficiency are secondary considerations that can be used to distinguish between equally effective alternatives. They should never supersede the first order of priority.

The most important aspect to be evaluated for these Rates should be the degree to which they succeed in electrifying the maximum amount of the fossil fuelled energy load. I.e., how effective are the Rates at electrifying the loads? Inducing electrification is, after all, the real underlying objective of these Rates. Will the new Rates remove the obstacles to that electrification and encourage those loads to be converted as quickly and fully as possible? How much conversion will it achieve, and how quickly?

CEABC recommends that BC Hydro should start its process in a similar way to how it approaches conservation and efficiency programs, namely by posing the question: Given that we want this load to convert to electricity, what will it take to induce that customer to make the conversion?

Beginning the process from the customer's point of view is what is done in planning customer conservation and efficiency programs. The objective is to remove the obstacles (economic or otherwise), and thereby induce and incent the customer to make the change. Only once effectiveness is assured, should the other questions be asked, as to how to achieve that result in a practical, least cost way, with fairness to all.

C. BC Hydro's proposed Rates are definitely a step in the right direction, in that they recognize that the Demand Charge is the most critical obstacle to new electrification customers.

The concept of the Demand Charge is specifically intended to cover the potential cost of the utility having to expand its capacities, either for generation, transmission, or distribution. Since the need to increase capacity is only triggered by the utility's peak load, it is only ever triggered by the load in the peak hours (usually the early evening). In the case of generation and bulk transmission capacities, it would only ever be triggered by a load that coincides with the system peak load, which is measured on the 4 coldest days of the winter season.

It's only when a customer load is actually coincident with the system peak load, that the need for new capacity could be triggered (and even then, only if that caused the new peak to exceed the peak of record). Accordingly, it's not the customer's peak load that should be assessed a Demand Charge, it's the customer's load that coincides with BC Hydro's system peak.

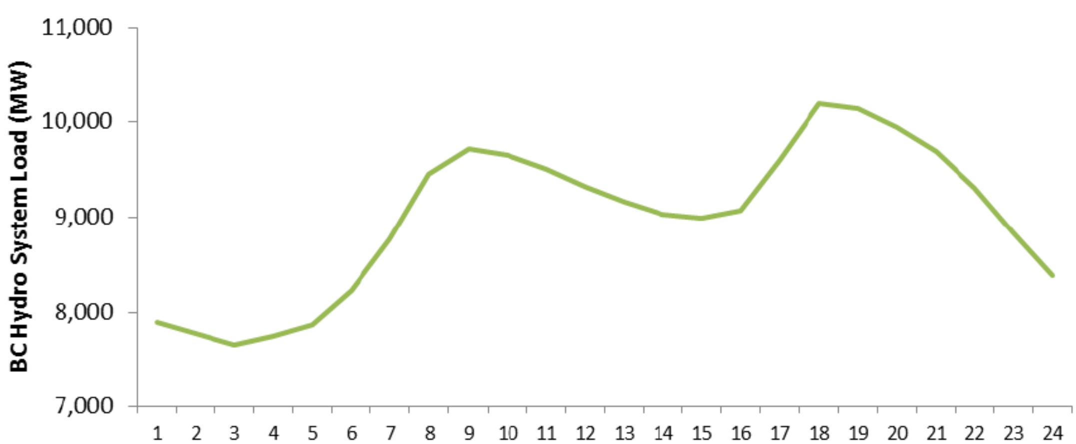
If a customer can manage its load so that it never augments the system peak, then it will never contribute to the need for expanded capacity, and theoretically there should be no need, or justification for imposing a Demand Charge. Most customers cannot guarantee they will not contribute to the system peak, but a customer that only takes its energy during the off-peak periods can give that assurance.

It is, perfectly logical, and therefore justified, that the Overnight Rate proposal explicitly recognizes that BC Hydro's need to expand its capacities is highly unlikely to be triggered by the load during the overnight period. Since these new loads will not contribute to the system peak load, there is no necessity for a Demand Charge.

CEABC anticipates that this Overnight Rate proposal should, therefore, be a very effective rate for encouraging the electrification of any fleets that can be recharged in the overnight period.

However, it could be made even more effective if BC Hydro were to "relax" the Zero-Demand-Charge time period by an hour at each end. This would recognize the fact that BC Hydro's load begins to drop off after 8:00 pm and declines by roughly 300 MW every hour, and it doesn't really increase again until after 7:00 am. The typical daily profile of BC Hydro's system load was depicted in Figure 1 below:[10]

Figure 1 Illustrative Load Profile of Depot Charging Load



From this chart, it appears there would still be no danger of augmenting the daily peak load if the Zero-Demand-Charge period were extended from 2100 to 0700,

[10] Ibid. page 4

giving a 10 hour opportunity for fleet recharging, instead of merely 8 hours. There is no real necessity to have the Zero-Demand-Charge period coincide with the definition of Light Load Hours. The period can be set at whatever the Overnight Rate defines it as, and the spreading of the charging over a longer period will make it easier for the customer to operate – without adding any additional cost to BC Hydro.

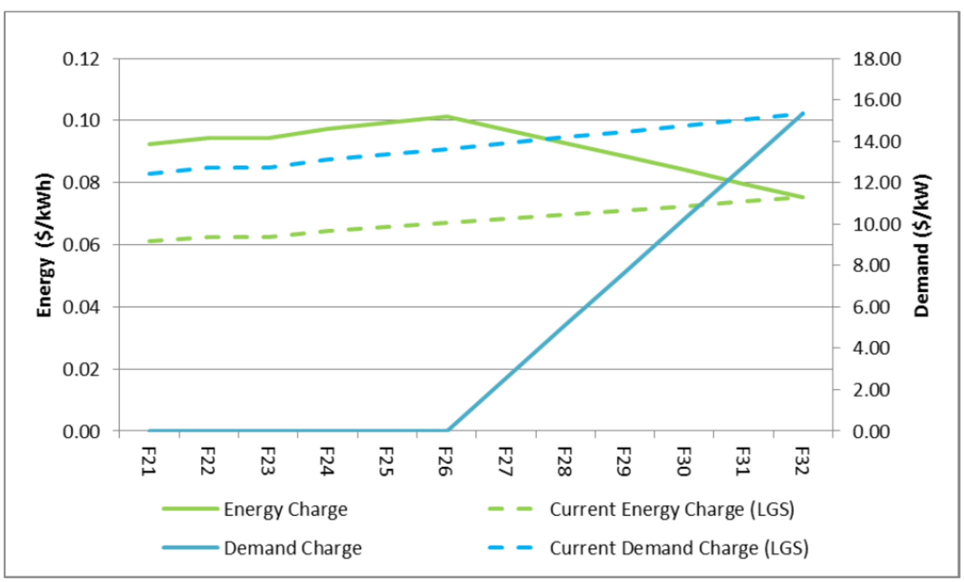
D. The Demand Transition Rate is also a step in the right direction, in that it relieves any potential electrification customers from the high cost of the Demand Charge in the early years when they would experience the lowest load factors.

A Demand Charge is particularly costly when the load factor is well below 50%. The reason is fairly simple: the customer must pay the Demand Charge on a peak load that is much higher than their average energy demand. The extra Demand Charge can more than double the effective cost of the energy they use. Once there are enough converted buses, they can stagger their recharging so as to more fully utilize the charging facilities and draw the load more evenly over time.

The Demand Transition Rate proposes a 6 year "holiday" from the Demand Charge, during which the Energy Charge would be elevated well above the normal rate for an LGS customer. The initial 6 year "holiday" period, is then followed by a 6 year "ramping" period when the Demand Charge is ramped up and the Energy Charge ramped down. After 12 years, the rate reverts to the normal LGS rate.

The Demand and Energy Charges over time are depicted in Figure 4 below:[11]

Figure 4 Proposed Demand Transition Rate Design Schematic



[11] Ibid. page 11

CEABC believes this proposed rate structure will be somewhat effective at inducing the desired fleet electrification. However, CEABC considers it to be very significant that BC Hydro believes the new rate will not be attractive to customers with load factors above 52%. Once load factors exceed 52%, the LGS rate will be more attractive.[12] This indicates that the new rate could be enhanced to induce even more electrification more quickly.

Accordingly, CEABC recommends 3 minor adjustments which could enhance the effectiveness with negligible cost to BC Hydro's other customers:

1. Rather than a fixed term ending in 2032 for all customers, the term could be set for each customer from the date of that customer's initial service. It appears that BC Hydro presently only contemplates one customer using this rate (i.e. TransLink). However, the rate should be available for other customers to enter at a later date.
2. The Demand Charge "holiday" period should be extended to 8 or even 9 years, rather than 6 years. A longer Demand-Charge-free period would offer a stronger incentive to overcome the high capital cost of conversion and thereby induce more potential fleets to electrify. One big obstacle with the 6 year "holiday" period is the turnover period for the existing fleets. Most fleet owners will be reluctant to convert their existing vehicles before they have completed their active service life. The "ramping" period can remain at 6 years, or even be reduced to 5 years.
3. Change the time definition of the peak load that is subject to the Demand Charge to exclude the period between 11:30 am and 4:00 pm. Given the "saddle" shape of BC Hydro's typical daily load profile, as depicted in Figure 1 above, there is a mid-day "dip" in the load of nearly 1,000 MW. It is quite possible that a fleet customer, such as TransLink, could schedule a good portion of its in-route recharging to be done during this 1,000 MW "dip" period, between 11:30 am and 4:00 pm, thus avoiding both the morning and afternoon peak periods. Since this would only be to BC Hydro's benefit (i.e. more evenly distributing the load during the day, while never augmenting the system peak load), the customer should be strongly incented to do this if it is possible.

E. BC Hydro should investigate the potential for using utility-scale batteries and "Smart" charging, as a means of avoiding the need to expand capacities.

[12] Exhibit B-4, response to BCUC IR 1.1.3

It seems that the biggest obstacle to the growth of electrification is the presence of the Demand Charge. And the real reason for the Demand Charge is to pay for the potentially heavy cost of having to expand the system capacities. In turn, this heavy potential cost is caused by the fear of increasing the system peak loads.

What if the loads could be managed so they never increased the system peaks? This would represent an ideal world, especially in terms of the more efficient use of all the system's resources.

It's clear from the load profile depicted in Figure 1 above, that BC Hydro could avoid much of the need to expand its capacities if it could merely "level out" the load over the 24 hours of the day, in such a way that it could avoid increasing any of the peak load periods.

In the case of large charging loads, such as those contemplated for the bus fleets, their charging needs could be accommodated with the existing generation and transmission capacities, and even with the existing distribution network facilities. What would be required would be the installation of strategically placed large scale battery packs and the use of "smart" charging software that could schedule charging to take place during the off-peak periods whenever possible. The necessary investment could be made by BC Hydro and/or the customer.

Of course the management of the charging scheduling would have to be worked out cooperatively between BC Hydro and its customers, but the economic incentives are significant for both.

A proper use of Demand Charges would be to induce customers to shift their load profiles to suit BC Hydro's system needs. Demand Charges could operate in much the same way as a Time-of-Use Energy Charge, inducing and incenting customers to operate more efficiently for the overall system's health (and cost).

CEABC recommends that the BCUC suggest that BC Hydro study and report back on the future potential for using the latest modern battery technology and "smart" scheduling software to more efficiently manage the customer loads to fit more efficiently within BC Hydro's system constraints.

Not all customer loads could be managed to optimize the utility's assets, but electric vehicle charging is one of those loads that has great potential for such active management – and the result would be to everyone's benefit. More efficient use of existing infrastructure and less need to expand capacities, would lead to lower rates for all.

F. Economic evaluations of the proposed Fleet Electrification Rates

BC Hydro evaluates each of the Rates in terms of its expected economic impact on the other ratepayers. This is essentially an estimate of whether, on a marginal or incremental basis, the new service will bring in revenues greater than the cost of providing the service. I.e. the evaluation attempts to estimate the expected "ratepayer impact".

The evaluations, however, do not look deeply into the consequences for the prospective new customers, or at the benefits to society in general (such as the reduction in greenhouse gases). However, since these rates are specifically intended to implement a Government policy to reduce greenhouse gas emissions (i.e. a societal benefit), it should be an important part of the evaluation to assess the impact on the society in general, and also to understand how the obstacles and incentives are being seen by the targeted new customers, which will have a critical impact on the expected degree of success at eliminating GHG emissions.

It's ironic that this approach is the complete opposite of the way DSM programs are evaluated. Although DSM programs are not the subject of this proceeding CEABC brings them into the discussion in order to point out the inconsistency in the way the proposed Fleet Electrification Rates are being evaluated compared to the way DSM programs are evaluated. The later being evaluated on the basis of the total resource cost or "TRC".

For DSM programs, the key focus is on the overall societal impact, while the impact on the general level of rates is almost completely ignored. To be comparable to the way the Fleet Electrification Rates are being evaluated, the DSM programs would have to be evaluated using a test called the Ratepayer Impact Measure test ("RIM" test) – a test which measures the impact on the utility's general rate levels. Or the Fleet Electrification Rates on the basis of TRC.

The proposed Fleet Electrification Rates are being evaluated using what is effectively an RIM test, whereas DSM programs on the basis of TRC. The CEABC appreciates that the BCUC has been given specific direction that a DSM measure may not be rejected because of its adverse impact on the utility's ratepayers but there is no apparent reason why the BCUC could not adopt TRC for Fleet Electrification or similar rates.[13]

If DSM programs were evaluated in the same way as the Fleet Electrification Rates, using an RIM test, then many of BC Hydro's Demand Side Measures would

[13] Subsection 4(6) of the DSM Regulation states that the BCUC cannot determine that a demand side measure is not cost-effective on the basis of the results of the Ratepayer Impact Measure test.

show that they would produce large adverse impacts on the general rate levels. This can be seen in the following table provided by BC Hydro:[14]

Table A-7 Benefit Cost Ratios

	LRMC ($105 per MWh)			Market Price ($30 per MWh)	
	Modified Total Resource Cost Test	Total Resource Cost Test excluding NEBs	RIM	Utility Cost Test	RIM
Rate Structures					
Residential Inclining Block Rate	n/a	n/a	n/a	n/a	n/a
General Service Rate	n/a	n/a	n/a	n/a	n/a
Transmission Service Rate	1.4	1.4	1.0	11.1	0.3
Total Rate Structures	**1.4**	**1.4**	**1.0**	**11.1**	**0.3**
DSM Programs					
Residential Sector					
Low Income	3.5	2.7	0.8	0.9	0.4
Non Integrated Areas	2.2	1.8	1.1	1.8	1.1
Retail	6.0	6.3	1.0	2.0	0.5
Home Renovation Rebate	1.9	1.5	1.0	2.3	0.5
Residential Sector Total	**2.6**	**2.1**	**0.9**	**1.6**	**0.5**
Commercial Sector					
LEM-C	4.0	2.4	1.1	2.5	0.4
New Construction	3.0	2.0	1.1	1.5	0.4
Commercial Sector Total	**3.8**	**2.3**	**1.1**	**2.2**	**0.4**
Industrial Sector					
LEM-I	4.4	3.1	1.2	1.8	0.4
Thermo-Mechanical Pulp	2.7	2.7	1.2	1.2	0.4
Industrial Sector Total	**3.9**	**3.0**	**1.2**	**1.6**	**0.4**
Total Programs	**3.6**	**2.6**	**1.1**	**1.7**	**0.4**
Energy Management Activities	n/a	n/a	n/a	n/a	n/a
Supporting Initiatives	n/a	n/a	n/a	n/a	n/a
Codes & Standards	n/a	n/a	n/a	n/a	n/a
PORTFOLIO TOTAL	**2.5**	**1.9**	**1.0**	**1.1**	**0.4**

The values in the far right column of this Table A-7 are the results of the Ratepayer Impact Measure test ("RIM" test) applied to each of the various categories of DSM Programs. The RIM test is the only benefit/cost ratio that measures the impact on the general level of the utility's rates.

The fact that the RIM ratios in that far right column are considerably less than 1.0 simply means that the billing revenues lost by the utility, as a result of each measure, are greater than the savings achieved by the utility.

A ratio of 0.5 means roughly that the lost billing revenues due to that measure (or category of measures) exceed the amount saved by BC Hydro by a factor of two. A ratio of 0.4 indicates the lost billing revenues exceed the savings by a multiple of 2.5, roughly speaking.

When compared to the very low ratepayer benefit/cost ratios for these DSM programs, the benefit/cost ratios calculated for the two proposed new Fleet Electrification Rates appear dramatically higher.

[14] Exhibit B-5, response to CEABC IR 1.1.5

Table 4 below shows the Ratepayer Benefit/Cost Ratios calculated for the proposed Overnight Rate:[15]

Table 4 Overnight Rate Ratepayer Impact

Time Period (Years)	Ratepayer Benefit Cost Ratio
5	1.13
10	1.43
15	1.42

The fact that these ratios exceed 1.4 indicates that the additional billing revenues being earned by BC Hydro from these new customers are roughly 40% greater than the actual incremental cost of providing the service (and this revenue is purely from the Energy charge, since there is no Demand Charge being levied). This new rate will apparently be very financially beneficial for BC Hydro, certainly far more beneficial than any of the Demand Side Measures undertaken over the past decade.

Table 7 below shows the Ratepayer Benefit/Cost Ratios calculated for the proposed Demand Transition Rate:[16]

Table 7 Demand Transition Rate Ratepayer Impacts

Time Period for Load Factor	F2021 - F2025	F2026 - F2029	F2030 - F2034
Load Factor	15%	30%	52%
Time Period used for Ratepayer Benefit Cost Analysis	5 Years F2020-F2024	10 Years F2020-F2029	15 Years F2020-F2034
Ratepayer Benefit Cost Ratio	0.74	1.04	1.16

Compared to DSM programs, the Benefit/Cost Ratio for this proposed rate is much more attractive to BC Hydro, even though it is not as attractive as the Overnight Rate. Still the ratio of 1.16 indicates the billing revenues are expected to exceed the marginal cost of providing the service by approximately 16%.

The critical question that has not been asked, but should be, is: How effective will this rate be at inducing the desired electrification of the bus fleets as fully and quickly as possible? BC Hydro offers no evaluation of that critical question.

G. The cost of new capacity is a highly conjectural assumption.

---

[15] Exhibit B-1, Application, page 37
[16] Ibid. page 47

When BC Hydro's analysis shows that the benefits exceed the costs by X%, that is based on a pretty sound understanding of the benefits (i.e. the billing revenues under the new rate), but on the cost side, the assumptions are theoretical and based on highly conjectural assumptions.

In particular, the costs of new capacities for generation, transmission and distribution are based on a table of assumed costs like the following:[17]

Fiscal Year	Energy Marginal Cost 2018 $/MWh	Energy Marginal Cost Nominal $/MWh	Generation Capacity Marginal Cost Nominal $/kW-yr	Distribution Capacity Marginal Cost Nominal $/kW-yr	Non-bulk Transmission Capacity Marginal Cost Nominal $/kW-yr
2020	23.19	24.34	39.88	26.24	52.48
2021	25.20	27.01	40.72	26.79	53.58
2022	28.24	30.87	41.54	27.33	54.65
2023	29.04	32.38	66.90	27.87	55.75
2024	29.59	33.66	68.23	28.43	56.86
2025	29.78	34.55	69.60	29.00	58.00
2026	30.50	36.08	70.99	29.58	59.16
2027	30.95	37.35	72.41	30.17	60.34
2028	30.98	38.13	73.86	30.77	61.55
2029	31.28	39.28	75.34	31.39	62.78
2030	32.06	41.06	76.84	32.02	64.04
2031	32.38	42.30	78.38	32.66	65.32
2032	32.69	43.56	163.89	33.31	66.62
2033	32.75	44.51	167.17	33.98	67.95
2034	33.78	46.84	170.51	34.66	69.31

These cost assumptions for the next 15 years are not known with any certainty. They are highly conjectural and may be questionable. For instance, why should the cost of new generation capacity suddenly jump in F2023? Or why should it double in F2032?

What is even more conjectural is that these very rough estimates of the costs in dollars per kW per year are simply multiplied by the customer's maximum demand level in each billing period in order to calculate the total cost to BC Hydro. This is a totally hypothetical cost. It is unlikely to actually happen. The actual cost for new capacity is a much more complex issue. What this means is that the cost side of all those benefit/cost ratios (i.e. the denominators in the ratios) is largely illusory – a pessimistic estimate, at best.

While these concerns are perhaps more suited to a general rate design application review, the CEABC wishes to table them in the context of the review of the Application because they are applicable to it, and are going to continually arise whenever BC Hydro brings forward new rate proposals in its effort to fulfill its government mandate to electrify more of B.C.'s fossil fuel energy.

[17] Exhibit B-3, BC Hydro response to BCUC request for ratio calculation models, Appendix E, Attachment 1, Input tab

All of which is respectfully submitted.

January 10, 2020

Clean Energy Association of B.C.