# FINAL ARGUMENT

## Clean Energy Association of British Columbia

## Re: British Columbia Hydro and Power Authority

## FISCAL 2022 REVENUE REQUIREMENTS APPLICATION

**Project No. 1599164**

**April 6, 2021**

# FINAL ARGUMENT of Clean Energy Association of B.C. ("CEABC")

# Re: B.C. Hydro and Power Authority ("BC Hydro")

# FISCAL 2022 REVENUE REQUIREMENTS APPLICATION

# ("Application" or "F22 RRA")

## I. INTRODUCTION

In view of the limited time available in the "streamlined" review process dealing with this Application, CEABC will address its observations and arguments to the following selected set of issues:

1) The use of the March 2020 Load Forecast, and the use of "Scenario A" to adjust for the impacts of the Covid-19 pandemic.

2) The impact of successful Demand Side Management on BC Hydro's rates.

3) The need for an EV Costs Regulatory Account and the accounting for electrification initiatives, in general.

4) Transfer of EV credits to Powerex.

5) CleanBC Industrial Electrification Rates (RS 1894 and 1895).

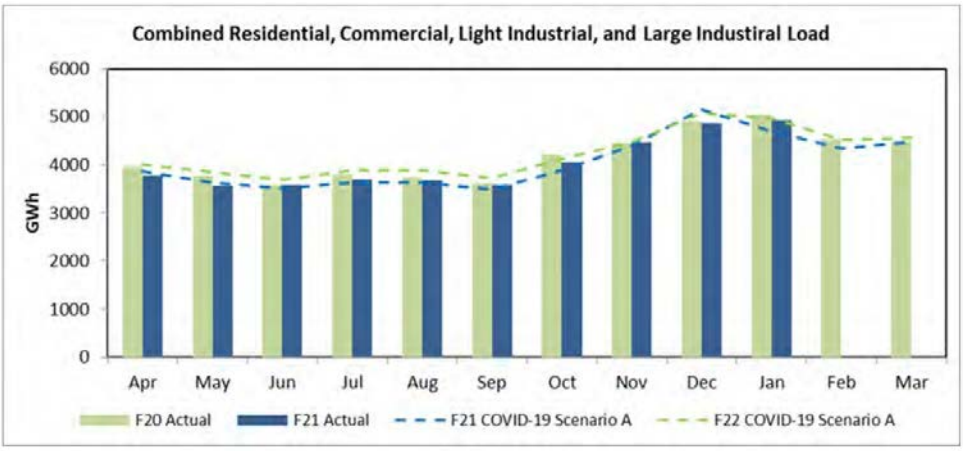
6) Electrification of the Montney Oil and Gas Fields.

## II. CEABC ARGUMENT

### 1) The use of the March 2020 Load Forecast, and the use of "Scenario A" to adjust for the impacts of the Covid-19 pandemic.

BC Hydro deals with its Load Forecast and adjustments in Chapter 3 of the Application. Section 3.1 states that*: "BC Hydro prepared a comprehensive 20-year load forecast (the March 2020 Load Forecast)… prior to the onset of impacts associated with the COVID-19 pandemic."* It then developed two scenarios intended to adjust for the impacts of the pandemic, of which: *"**Scenario A** is used in the calculation of the Test Period revenue requirements."*

In Section 3.2 of the Application, BC Hydro provided charts to illustrate the Scenario A adjusted loads for each major load sector and, at CEABC's request, also provided the following chart showing the impact of Scenario A on the combined load of all sectors:[1]




CEABC accepts that the Scenario A adjustments, as designed by BC Hydro, appear to reasonably reflect the impacts of the Covid-19 pandemic on the loads in F2021, in so far as was feasible prior to the submission of the Application. It remains to be seen how far into the future the pandemic will continue to impact electricity loads. BC Hydro has made the following predictions going out to F2025 (although these go beyond the 1-year test period ("Test Period") of this Application):[2]

**Table 3-2 COVID-19 Scenarios Difference from March 2020 Reference Case**

| Billed Sales Projections - After Rate Impacts and after Demand-Side Management[1] | | | | | | |
|---|---|---|---|---|---|---|
| Fiscal Year | Main Customer Sectors[1] | | | | | |
| | Residential Sales (GWh) | Commercial Sales (GWh) | Light Industrial Sales (GWh) | Large Industrial Sales (GWh) | Change In Domestic Sales (GWh) | Change In Domestic Sales (%) |
| **COVID-19 Scenario A Relative to March 2020 Forecast** | | | | | | |
| F2021 | 454 | -1,138 | -505 | -2,015 | -3,204 | -6 |
| F2022 | 0 | 0 | -457 | -1,126 | -1,582 | -3 |
| F2023 | 0 | 0 | -458 | -887 | -1,346 | -2 |
| F2024 | 0 | 0 | 0 | -790 | -790 | -1 |
| F2025 | 0 | 0 | 0 | -790 | -790 | -1 |
| **COVID-19 Scenario B Relative to March 2020 Forecast** | | | | | | |
| F2021 | 607 | -3,259 | -680 | -3,294 | -6,626 | -12 |
| F2022 | 187 | -1,626 | -768 | -4,918 | -7,124 | -13 |
| F2023 | -295 | -734 | -809 | -2,963 | -4,801 | -9 |
| F2024 | 0 | 0 | 0 | -790 | -790 | -1 |
| F2025 | 0 | 0 | 0 | -790 | -790 | -1 |

[1] Exhibit B-5, response to CEABC IR 1.6.2, Attachment 1
[2] Exhibit B-2, page 3-13

This table shows that the adjustments under Scenario A are much less severe than those under Scenario B,[3] and BC Hydro confirmed that Scenario A has tracked reasonably well with the actual loads up to the time of filing of the Application.

CEABC is concerned that both adjustment scenarios are predicting a persistent reduction that extends to F2024 and F2025. It is only about a 1% decline in overall combined load, but it is all confined to the Large Industrial sector, where it constitutes almost a 5% reduction. This is a very significant predicted reduction and CEABC suggests that it should be thoroughly examined in the next RRA. Why should the pandemic be expected to cause such a deep and long lasting decline in Large Industrial loads?

CEABC is also concerned that the March 2020 Load Forecast used for this Application excludes much of the necessary electrification loads required to achieve the GHG reduction goals targeted by the Government in its CleanBC Plan. Hopefully, this omission does not impinge too severely on the immediate 1-year test period being used for this F2022 RRA, but this shortcoming must be remedied as soon as possible, in any future plans and RRAs.

More detail about the March 2020 Load Forecast is provided in Exhibit B-8, filed in the BC Hydro LTRP Filing Date proceeding. Therein, BC Hydro describes the Electrification Scenarios that were used in the forecast, stating that:

> *"The Government of B.C.'s CleanBC Plan established GHG reduction goals for 2030 and includes actions to achieve the first 75 per cent of these reductions…*
>
> *Table 1 below specifies the electrification measures included in the March 2020 Load Forecast as well as three illustrative electrification scenarios. These scenarios were derived from a report by NAVIUS entitled* ***British Columbia Electrification Impacts Study: Forecasting the Impact of Achieving British Columbia's Greenhouse Gas Emissions Targets on Provincial Electricity Consumption****. This report estimates the total demand from electrification if provincial GHG reduction targets are achieved." [emphasis added]*

In Exhibit B-8 (filed in the LTRP Filing Date proceeding, pages 4-6), BC Hydro explains that the Navius report concludes that all of the scenarios described in Table 1 are required in order to achieve the CleanBC Plan GHG reduction goals for 2030. However, in its March 2020 Load Forecast, BC Hydro only includes the first level of electrification activities, captioned "Load Forecast – Reference case", on the grounds that these: *"… have a higher level of probability of materializing…".*

Included in the Navius scenarios that go beyond the Reference Case scenario, there are incremental electricity loads that are stated to result from "strong policies" (presumably by Government). All of these incremental loads are necessary to meet the

[3] Scenario A shows 6% and 3% reductions for F21 and F22, compared to 12% and 13% reductions for Scenario B. Scenario A appears to be tracking the actuals better than Scenario B.

GHG reduction goals in the CleanBC Plan. According to Table 1, "strong policies" will result in additional electrical loads amounting to:

- 7,000 GWh for light duty EV load, plus 700 GWh for medium and heavy-duty vehicle electrification, although the majority will be after 2030;
- 5,600 GWh for Oil & Gas subsector load, with most of that growth occurring before 2030;
- plus an additional 3,000 GWh from electrification of the Oil & Gas subsector;
- plus an additional 4,000 GWh for built environment, primarily on the South Coast, with more than half before 2030;
- plus an additional 10,000 GWh for LNG and Mining electrification, with most showing up before 2030

These scenarios described in the Navius report are not outcomes that BC Hydro can simply assess as to their: "*higher or lower levels of probability of materializing*". These are outcomes that must be accepted as mandatory outcomes that BC Hydro must plan on achieving, if British Columbia is to reach the emission reduction levels stated in the Climate Change Accountability Act. And, as such, they need to be incorporated as the Reference Case in all of BC Hydro's planning.

These incremental loads can total to more than 15,000 GWh/year by the year 2030. When CEABC asked BC Hydro why it had not included adjustments for these electrification loads in its load projections for this Application, it responded:

> *"The questions and issues related to BC Hydro's long-term load forecast, and alignment with the long-term goals of the CleanBC plan are best addressed as part of the review of BC Hydro's 2021 Integrated Resource Plan."*

It is unfortunate that, due to the timing of this Application, and the brevity of the review process, BC Hydro cannot, at this time, incorporate a load forecast which fully reflects the findings of its own Navius consultant's report. This means that all of its activities and spending plans are effectively based on a Reference Case projection that is certain to not achieve BC Hydro's objectives – and these are the mandatory objectives of the Government and the people of British Columbia.

In view of the fact that this Application is for only a 1-year test period, the shortcomings of this omission are, hopefully, limited. However, if ambitious objectives are to be achieved by 2030, it must be recognized that significant efforts must be underway as early as possible. Fiscal 2023 will leave only 7 years to achieve those objectives.

CEABC believes it is essential that BC Hydro makes the connection, very visibly, between its near-term activities (as reflected in its revenue requirements applications) and its longer-term objectives (as reflected in its Long Term Resource Plan), and that this connection can be readily seen by the Government, by the regulator, by the interveners, and by the people of British Columbia.

CEABC looks forward to BC Hydro being able to incorporate the Navius findings as soon as possible, as the Reference Case in all of its future activities and plans, including its next Revenue Requirements Application ("F23 RRA"), and certainly in its Long Term Resource Plan ("LTRP" or "IRP") due to be filed for review in December, 2021.

## 2) The impact of successful Demand Side Management on BC Hydro's rates.

BCUC staff posed the following question as to whether DSM savings that reduce the overall revenue requirement would also necessarily reduce rates to all ratepayers:[4]

> *"… a DSM portfolio with a net levelized cost less than $33 per megawatt hour would still be cost effective under the utility cost test and would have a positive impact on BC Hydro's revenue requirement.*
>
> *So does it follow that because the overall revenue requirement may be reduced with additional DSM expenditure, that all customer classes would benefit from a reduction in rates?"*

BC Hydro responded: [emphasis added]

> ***"…** DSM operates a little bit differently than what we might think of with typical expenditures within BC Hydro.*
>
> *So as much as our DSM expenditures can have a downward pressure on the overall cost that BC Hydro has to recover, <u>it</u> <u>doesn't</u> <u>follow</u> <u>necessarily</u> <u>that</u> <u>it</u> <u>has</u> <u>a</u> <u>downward</u> <u>pressure</u> <u>on</u> <u>rates</u>. And so in this surplus environment it doesn't necessarily follow that we have a downward pressure on rates just because we have a downward pressure on revenue requirement.*
>
> *So the $19 being lower than the 33 is an indication with the utility costs test that we have a lower revenue requirement as a result of our DSM expenditures, but <u>we</u> <u>do</u> <u>have</u> <u>an</u> <u>upward</u> <u>pressure</u> <u>on</u> <u>rates</u> <u>and</u> <u>that</u> <u>was</u> <u>part</u> <u>of</u> <u>the</u> <u>consideration</u> <u>in</u> <u>the</u> <u>moderation</u> <u>strategy</u> going back to the '17 and '19 RRA that was considered and continues to be a consideration for us moving forward."*

CEABC has been pointing out this anomaly since well before the F17-F19 RRA. This does not mean that CEABC members are opposed to effective DSM. In fact, they are emphatically in favour of encouraging the most efficient usage of energy.

However, CEABC has also frequently pointed out that the conventional metrics used to measure the effectiveness of DSM measures (namely, the Total Resource Cost and the Utility Cost metrics), do not assess the impact of those measures on the general rate levels the utility has to charge – principally because they do not consider the

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[4] Transcript, Vol 2, page 283

impact of the lost billing revenues, which can very well exceed all the utility's savings. The only metric that assesses this impact is the Ratepayer Impact Measure (RIM) test.

It is true that participating customers will see bill reductions due to their reduced consumption. However, it may also be true that rate levels in general will have to rise because of the reduction in overall load and a continual increase in fixed costs. In periods when BC Hydro is marketing surplus energy at prices much below its billed rates to customers, this will mean that any energy saved by successful DSM will have to be sold off at prices that do not compensate for the lost billing revenues. (The same would apply whenever BC Hydro is able to fill any energy deficits at prices below its billing rates.) This, in turn, means that customers in general will face rate level increases as a result of the success of the DSM measures.

While it may be true that the overall revenue requirement will be reduced by cost effective DSM measures that does not mean that the utility's rates will be reduced. In fact, the rates in general will have to increase whenever the reduction in load is greater than the reduction in revenue requirement. The only metric that reflects this impact is the RIM test.

While it may seem like an anomaly, this upward pressure on rates is explained by the fact that the greatest portion of BC Hydro's costs are fixed in nature. The actual recoverable value of the energy "saved" is much less than the billing rates charged to ratepayers. When one customer reduces their energy consumption, the portion of BC Hydro's fixed costs that customer had been paying must now be shifted to other customers, thus leading to a general rate increase.

And, as stated in BC Hydro's response, this upward pressure on rates is a significant reason why BC Hydro has adopted a more moderated approach to its DSM programs.

CEABC believes this is why DSM measures, designed to encourage efficient usage of electricity, should be aggressively coupled with other initiatives designed to take up that "saved" electricity and market it to new customers, thus avoiding a net loss of load – and of billing revenues – while still assuring the most efficient usage of the energy.

While it is unquestionably a good idea to use energy as efficiently as possible, the reduction in loads will lead to general rate increases, unless the utility remarkets that saved energy (and capacity) to new customer loads, to recover its billing revenues. Without new loads to absorb the "saved" energy, the net result of the reduced loads will be a general rise in rates.

How significant is the economic impact of this, on ratepayers?

BC Hydro summarized the Benefit/Cost Ratios of its DSM measures in Table 5 of Appendix W.[5] However, CEABC noted that evaluating these metrics using a hypothetical value for saved energy of $105/MWh was inappropriate. Accordingly,

[5] Exhibit B-2-2, Appendix W, BC Hydro's DSM Annual Report for Fiscal 2020, page 12, Table 5

CEABC asked that the Ratepayer Impact Measure Test be recalculated using saved energy values of $30 and $24, which more closely align with the actual expected value of any energy savings.[6] BC Hydro responded with the following table:[7]

**Benefit Cost Ratios**

| | **$30/MWh** | **$24/MWh** |
|---|---|---|
| | Ratepayer Impact Measure Test | Ratepayer Impact Measure Test |
| **Rate Structures** | | |
| Residential Inclining Block Rate | n/a | n/a |
| General Service Rate | n/a | n/a |
| Transmission Service Rate | 0.3 | 0.3 |
| **Total Rate Structures** | **0.3** | **0.3** |
| **DSM Programs** | | |
| *Residential Sector* | | |
| Low Income | 0.4 | 0.3 |
| Non Integrated Areas[1] | 0.4 | 0.4 |
| Retail | 0.4 | 0.4 |
| Home Renovation Rebate | 0.4 | 0.4 |
| *Residential Sector Total* | 0.4 | 0.4 |
| *Commercial Sector* | | |
| LEM-C | 0.4 | 0.3 |
| New Construction | 0.4 | 0.4 |
| *Commercial Sector Total* | 0.4 | 0.3 |
| *Industrial Sector* | | |
| LEM-I | 0.4 | 0.3 |
| Thermo-Mechanical Pulp | n/a | n/a |
| *Industrial Sector Total* | 0.4 | 0.3 |
| **Total Programs** | **0.4** | **0.4** |
| Energy Management Activities | n/a | n/a |
| Supporting Initiatives[2] | n/a | n/a |
| Codes & Standards | n/a | n/a |
| **Portfolio Total[3]** | **0.3** | **0.3** |

Using these more realistic values for the saved energy the Benefit/Cost ratios for most of the items in the table are now seen to be in the range of 0.3 to 0.4. This indicates that the costs borne by the utility (when lost billing revenues are included) for each of these measures are roughly 2.5 to 3 times the value of the savings (including both the energy and capacity savings to the utility). This is a significant cost premium, over and above the value of the benefits. It should furnish a strong incentive for the utility to want to remarket that significant amount of "saved" energy and capacity, by finding and encouraging incremental customer loads.

What is the extent of that saved energy? If we examine the amounts of the loads that have been reduced by the various DSM measures, BC Hydro offers the following summary in its Service Plan:[8]

[6] Exhibit B-5, as discussed in CEABC IR 1.8, $30 corresponds to BC Hydro's Mid-C price forecast and $24 corresponds to Puget Sound Energy's Mid-C price forecast.
[7] Exhibit B-5, BC Hydro response to CEABC IR 1.9.2, Attachment 1
[8] Exhibit B-2-2. Appendix Q, F2021 BC Hydro Service Plan, page 14 of 29

| Performance Measure(s)[1] | 2018/19 Actuals | 2019/20 Forecast | 2020/21 Target | 2021/22 Target | 2022/23 Target |
|---|---|---|---|---|---|
| 4.a Energy Conservation Portfolio (New incremental GWh/year)[2] | 868 | 734 | 700 | 500 | 500 |
| 4.b Clean Energy (%) | 97.4[3] | 96.4 | 93.0 | 93.0 | 93.0 |

And it subsequently provided the revised numbers for F2019 and F2020 as 1210 and 722 GWh, respectively.[9] That indicates that the total amount of annual "saved" energy will have increased by approximately 3,600 GWH per year, over this 5-year period.

If the cost of this saved energy is 3 times the value of the savings, what does that imply in terms of an overall net cost to ratepayers? The answer to this question can be gleaned from BC Hydro's present value calculations in the following table:[10]

| SUMMARY PV DATA | Energy Benefits ($30/MWh) | Capacity Benefits (T&D) | Capacity Benefits (Gen) | Utility NEBs | Non-Incentive Costs | Incentive Costs | Lost Revenues | RIM Benefit Cost ($30/MWh) |
|---|---|---|---|---|---|---|---|---|
| **Rate Structures** | | | | | | | | |
| Residential Inclining Block Rate | $0 | $0 | $0 | $0 | $0 | $0 | $0 | n/a |
| General Service Rate | $0 | $0 | $0 | $0 | $0 | $0 | $0 | n/a |
| Transmission Service Rate | $5 | $0 | $1 | $0 | $0 | $0 | $21 | 0.29 |
| **Total Rate Structures** | **$5** | **$0** | **$1** | **$0** | **$0** | **$0** | **$21** | 0.29 |
| **DSM Programs** | | | | | | | | |
| *Residential Sector* | | | | | | | | |
| Low Income | $3 | $0 | $2 | $0 | $1 | $3 | $10 | **0.39** |
| Non Integrated Areas | 0.4 | 0.0 | 0.0 | 0.0 | 0.7 | 0.1 | 0.1 | **0.44** |
| Retail | $2 | $0 | $2 | $0 | $1 | $1 | $8 | **0.45** |
| Home Renovation Rebate | $4 | $1 | $4 | $0 | $1 | $4 | $16 | **0.44** |
| *Residential Sector Total* | **$10** | **$1** | **$8** | **$0** | **$4** | **$8** | **$34** | **0.43** |
| *Commercial Sector* | | | | | | | | |
| LEM-C | $11 | $1 | $4 | $0 | $4 | $4 | $30 | **0.40** |
| New Construction | $4 | $0 | $1 | $0 | $1 | $2 | $9 | **0.42** |
| *Commercial Sector Total* | **$14** | **$1** | **$5** | **$0** | **$4** | **$7** | **$39** | **0.40** |
| *Industrial Sector* | | | | | | | | |
| LEM-I | $17 | $1 | $5 | $0 | $3 | $7 | $48 | **0.39** |
| Thermo-Mechanical Pulp | $0 | $0 | $0 | $0 | $0 | $0 | $0 | **n/a** |
| *Industrial Sector Total* | **$17** | **$1** | **$5** | **$0** | **$3** | **$7** | **$48** | **0.39** |
| **Total Programs** | **41** | **3** | **18** | **0** | **11** | **22** | **120** | **0.41** |
| Energy Management Activities | $7 | $1 | $4 | $0 | $11 | $8 | $22 | **n/a** |
| Supporting Initiatives | $0 | $0 | $0 | $0 | $13 | $0 | $0 | **n/a** |
| Codes & Standards | $0 | $0 | $0 | $0 | $5 | $0 | $0 | **n/a** |
| **PORTFOLIO TOTAL** | **$53.42** | **$4.44** | **$22.56** | **$0.00** | **$40.09** | **$30.52** | **$163.49** | **0.34** |
| | **TOTAL BENEFITS** | | **$80.43** | | **TOTAL COSTS** | | **$234.10** | |

From the totals at the bottom, it is apparent that the overall DSM Portfolio has a Benefit/Cost Ratio of $80.34/$234.10 per MWh[11] (i.e. the ratio of 0.3, as shown in the previous table), which means that the costs exceed the benefits by approximately $154 per MWh (in present value terms). If one applies that net cost per MWh to the 3,600 MWh of load reductions "saved" over the 5-year period in the Service Plan, that would amount to a present value burden on ratepayers of approximately $550 million – and that is just for the load reduction achieved during this 5-year period.

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[9] Exhibit B-5, response to CEABC IR 1.2.1.2
[10] Exhibit B-5, BC Hydro response to CEABC IR 1.9.2, Attachment 1
[11] When energy savings are valued at a realistic $30/MWh

It is difficult for the average ratepayer to grasp how significant a $550 million present value cost is to the ratepayers, however, to put it in perspective, when BC Hydro brought its Site C application to the Joint Review Panel in 2013, BC Hydro judged Site C to be far superior to the next best alternative by virtue of a $150 million present value net benefit. When viewed from this perspective, a $550 million present value net cost should be regarded as very significant – almost 4 times the originally proposed go/no-go value premium of the Site C project. And it should provide a significant incentive to actively remarket as much of that "saved" energy as possible, as quickly as possible, to mitigate rate increases.

With regard to its efforts to remarket that "saved" energy, BC Hydro was asked to provide a table: *"showing the GWh of load added (or expected to be added) over the same 5-year period, due to BC Hydro's programs in support of the CleanBC plan to increase the use of clean energy and shift away from reliance on fossil fuels."*[12]

To this request, BC Hydro responded with the following progress figures for its Low-Carbon Electrification programs:

**The table below shows the GWh load added and forecast to be added as a result of the Low Carbon Electrification (LCE) Projects/Programs that BC Hydro has undertaken and plans to undertake over the five-year period in the request.**

| Performance Measure(s) | 2018/19 Actuals | 2019/20 Actuals | 2020/21 Forecast | 2021/22 Forecast | 2022/23 Forecast |
|---|---|---|---|---|---|
| Low Carbon Electrification Portfolio (New incremental GWh/year) | 107.0 | 213.5 | 65.4 | 148.4 | 9.6 |
| Low Carbon Electrification Portfolio (Expenditure $ million) | 7.1 | 16.9 | 7.6 | 15.5 | 4.8 |

Therefore, in summary, over this 5-year period, BC Hydro will have spent approximately $440 million[13] to reduce its load by roughly 3,600 GWh per year and, over the same period, it will have spent about $50 million on efforts to add incremental load of approximately 550 GWh, thus remarketing a portion of that "saved" energy.

In view of these findings, CEABC agrees with BC Hydro that a moderation strategy with respect to DSM measures is appropriate, and CEABC encourages BC Hydro to pursue cost effective electrification as broadly and rapidly as possible, as a means to remarket the "saved" energy and thereby mitigate the upward pressure on its rates.

## 3) The need for an EV Costs Regulatory Account and the accounting for electrification initiatives, in general.

BCH's EV charging station program ("EV Station Program") is an important component in achieving the CleanBC Plan goals for GHG reductions in British Columbia. This program needs to be improved so the costs and benefits are more readily apparent.

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[12] Exhibit B-5, CEABC IR 1.2.2.1
[13] Exhibit B-5, response to CEABC IR 1.2.1.1

Otherwise, future BCH programs and initiatives to increase revenues and reduce GHGs through additional sales of electricity may be more difficult to implement.

Additional transparency will result in improved understanding and broader acceptance.

By the end of F2021, BC Hydro expects to have 98 charging stations operating at 71 sites and has an additional 57 planned for the coming year.[14] It also supplies electricity to a number of other competitors who have charging stations across the province.

The $4.8 million[15] of capital that BC Hydro spent on its charging stations in F2020 and F2021 has not been charged to the ratepayers in the revenue requirements. Instead, it has been held in abeyance until those expenditures have been approved by the BCUC to qualify as "prescribed undertakings" under the Greenhouse Gas Reduction Regulation ("GGRR"). BC Hydro is now seeking approval for a new Electric Vehicle Costs Regulatory Account, which will be used to hold those F2020 and F2021 capital expenditures and amortize them to the ratepayers in future revenue requirements applications.

Rather than creating another regulatory account, CEABC proposes an improved alternative arrangement could be set up.

The following response from BC Hydro describes the approach it is currently planning for the EV Station Program:[16]

> *"… And so as it relates to Fiscal '20 and Fiscal '21, there are only costs definitely -- there are only costs involved and they're going into that regulatory account.*
>
> *Going forward, we've not proposed the continued use of that regulatory account, and again the reason is we're embedding those costs in the revenue requirement in the place where they belong, for lack of a better word. So the operating costs are part of operating costs. The cost of energy is part of the cost of energy and the revenues will be part of revenues. And therefore those variances, all of those variances, actually more than two regulatory counts involved there potentially because those variances will go wherever they relate. So if there's a revenue variance, it goes in the load variance regulatory count; if there's an amortization variance it would go in the total capital editions regulatory account variance. The only place where there's no such a variance would be with respect to operating costs. With cost of energy it will go into one of the cost of energy variance accounts.*
>
> *So there's actually multiple accounts at play when we look on a go-forward basis starting in fiscal 2022."*

To summarize the approach described by BC Hydro:

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[14] Exhibit B-5, responses to CEABC IR 1.7.3 and 1.7.4
[15] Exhibit B-2, page 7-13
[16] Transcript, Volume 1, page 236

1. The capital costs from the F2020 and F2021 charging stations will go into this new EV Charging Costs Regulatory Account and be amortized to the ratepayers in subsequent revenue requirements applications.
2. Future revenues from EV charging will be forecast and any variance from that forecast will go to the Load Forecast Variance Account to be charged or refunded to the ratepayers in subsequent revenue requirements applications.
3. If there's any future amortization variance, it will go to the Total Capital Additions Regulatory Account, to be charged or refunded to the ratepayers in subsequent revenue requirements applications.
4. If there's an energy cost variance, it will go into one of the Cost of Energy variance accounts, to be charged or refunded to the ratepayers in subsequent revenue requirements applications.
5. Forecasts of operating costs go directly to the revenue requirements but, since there is no regulatory account to hold any variances, any variances from those forecasts will affect the shareholder's Net Income. This seems to be the only instance where BC Hydro's management will be held accountable by its shareholder

This appears to be a very complex system, involving costs and revenues flowing through a number of different regulatory accounts, with most variances ending up back on the ratepayers, and it does not appear to produce an overall picture of the business operation as a whole.

BCH speaks about separating out the revenues from the operating costs and capital costs and energy costs and dealing with each separately. With such a complex system, it will be very difficult to track the overall costs and benefits of the program.

All of the costs and benefits should be considered as integral parts of managing a business – it is only by considering them all together that one can determine the net profit or loss from the business, or from any component of the business.

The EV Station Program should be operated as a transparent profit-making entity.

The CEABC proposes that the following alternative arrangement be used:

- The EV Station Program, as a whole, should be set up as a profit-making entity (and not necessarily using a regulatory account).
- There should be an accounting entity set up to surround the entire EV Station Program. All the costs and benefits, including revenues, should flow into that entity, so that a profit or loss can be determined for the business as a whole (and, preferably, for each charging station within the entity).
- Revenues should be forecast to ensure that the entity makes a profit for ratepayers (i.e. revenues forecast to exceed operating costs + energy costs + amortization + interest charges + return on capital).

- Any variance from the revenue forecast should not flow through a regulatory account but, rather, should go directly to the Net Income. This would improve management accountability for the overall success or failure of the program.
- Amortization rates for the charging station infrastructure should, to the extent possible, be set on the basis of usage rather than time. This is to ensure that the amortization of the assets will be in keeping with the growth of the business over time, rather than being excessively large in the early years, when the business is in its growth and development stage.

The fundamental concept of the above arrangement is that the ratepayers should only benefit, and not lose, from this business initiative.

Deferral account treatment can be considered appropriate when the variances from a forecast are truly outside of management's control – i.e. results are exclusively determined by external forces, not by management's decisions.

However, in this case, it would be better to avoid the deferral account treatment for two reasons:

1. The outcomes are not entirely out of the control of BC Hydro management. Management has many options open to it to achieve the targeted results, and management needs to take responsibility for that achievement.
2. When the forecast is set to achieve the CleanBC GHG reduction targets, the potential for gains or losses vs. the forecast will likely be asymmetrical. The chances of exceeding the forecast electrification revenues are very much less than the chances of falling short. Which means that the chances that the ratepayers will miss out on potential gains are much less than the chances that they will be protected from potential losses.

Although these comments are directed specifically at the EV Station Program initiative, CEABC can envision BC Hydro operating its entire portfolio of electrification initiatives (not merely the EV Station Program), in a similar way, as a transparent business entity. CEABC believes that this would be very similar to the way BC Hydro manages its portfolio of DSM measures.

## 4) Transfer of EV credits to Powerex.

In response to IRs from the British Columbia Old Age Pensioner's Organization ET AL ("BCOAPO") about carbon credits ("Credits") relating to BCH's ownership or operation of electric vehicle charging stations BCH provided the following responses:[17]

[17] Exhibit B-5, BCH responses to BCAOPO IRs 1.67.1 and 1.67.1.3

*"Yes, BC Hydro received 137 low carbon fuel credits relating to the ownership/operation of its electric vehicle charging stations for the 2018 calendar year. BC Hydro continues to work with government on the allocation of the calendar 2019 and 2020 credits related to electric vehicle charging stations.*

*BC Hydro transferred the 137 carbon credits for calendar year 2018 to Powerex and these were monetized in fiscal 2020 and included in Powerex fiscal 2020 Trade Income which is included in BC Hydro's revenue requirement."*

In the Web-Based Session the CEABC asked whether the transfer to Powerex was made in accordance with the Transfer Pricing Agreement between BCH and Powerex to which BCH responded:[18]

*"…They're not transferred under the transfer pricing agreement or any other agreement, I don't believe. They're transferred at zero cost and therefore all the revenues generated by Powerex stay in Powerex and then are reflected in their trade income and therefore provided to ratepayers via the trade income deferral account."*

Ultimately this discussion led to BCH responding in the form of an undertaking to Commissioner Morton which states in part:[19]

*"BC Hydro transfers its low carbon fuel credits to Powerex in accordance with section 8 of the Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act and section 11.11 of the Renewable and Low Carbon Fuel Requirement Regulation. The transfer is made at zero cost pursuant to an agreement between the parties, and all revenue earned by Powerex from the sale of credits flows back to BC Hydro ratepayers via Trade Income and the Trade Income Deferral Account."*

Powerex's overheads also reduce BCH's net income from the sale of Credits[20] and potentially other Powerex trading activities that produce losses but are netted against the income from these sales before Powerex's and BCH's net incomes are consolidated.

The CEABC's concern is that by transferring these credits to Powerex the income received when Powerex's disposes of them becomes consolidated in Powerex's net or Trade Income and subsequently is consolidated into BCH's net income. There is no apparent way to track the specific value of these Credits. A similar situation occurs when BCH disposes of the renewable energy credits ("RECs") it retains pursuant to certain electricity purchase agreements it has entered into with independent power producers ("IPPs"). The value of these credits reduces BCH's actual cost of purchasing

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[18] Transcript, V1, page 232-233
[19] Exhibit B-9 , BC Hydro Undertaking No. 24, page 2
[20] Transcript, V1, page 233

electricity, but it is impossible to track the financial value of the benefit that BCH receives from their sale.

The CEABC recommends that the Transfer Pricing Agreement be amended to include the sale of Credits, RECs or similar products ("Products") and that amendments include a mechanism for tracking the value of the Products sold. Alternatively, that all transfers of Products from BCH to Powerex be recorded by separate agreements that include a mechanism for tracking the value of the Products sold.

## 5) CleanBC Industrial Electrification Rates (RS 1894 and 1895).

In a response to CEABC[21] and BCUC[22] IRs about the CleanBC Industrial Rates (RS 1894 and 1895) (collectively "CleanBC Rates") BCH said:

> *"…The Application assumes no incremental loads, costs, or revenues associated with these new rate schedules during the test period.*
>
> *BC Hydro's load forecasts typically only reflect rates in place when the forecasts are developed. Therefore, the March 2020 Load Forecast and COVID-19 Scenarios do not explicitly incorporate the new industrial electrification rate schedules implemented pursuant to Order in Council No. 657.*
>
> *Because RS 1894 applies to new customer plants, which typically take multiple years to build, we expect no additional associated with this rate in the test period. Given the lead time required for existing customers to build eligible projects, we also expect RS 1895 to have little impact on the test period…*
>
> *… In general, BC Hydro expects that the CleanBC industrial electrification rates will attract incremental clean industry, innovation, and fuel switching customers resulting in increased load while also supporting the Government of B.C.'s climate change objectives outlined in CleanBC program."*

In the Web-Based Session the CEABC asked BCH what it was going to do to promote the CleanBC Rates during the Test Period. BCH indicated that almost immediately after these rates were announced, it started taking inquiries from customers about their eligibility for the rates. BCH said its key account management group was talking to its industrial customer group about the CleanBC Rates and the eligibility requirements.

When asked about whether it is budgeting any additional amounts to advertising or hiring any additional staff, BCH indicated that:

> *"…all of that will come about through our electrification plan and what we bring forward in the next revenue requirements application…"*

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[21] Exhibit B-5, BCH response to CEABC IR 1.4.1
[22] Exhibit B-4, BCH response to BCUC IR 1.8.1

The next RRA will be for the period commencing fiscal 2023 which would mean a significant delay in the implementation of a comprehensive marketing and delivery program. Customers have to be made aware of the new rates and then satisfied that the necessary arrangements will be made to deliver electricity to their new or retrofitted facilities before they will make final investment decisions ("FID"). These decisions require certainty and it is critical that the FID process be initiated as soon as possible.

In the Web-Based Session and in response to questions by CEABC, BCH said:[23]

> *"… There is substantial effort going on today with our base resources. So we have a very large pipeline of projects in the hopper in the provincial pipeline, if you will, and they include traditional economic development projects like mines and such, oil and gas projects, there's a number of electrification projects including expansion at existing facilities, and then greenfield projects, and then there's a number of clean tech projects that are a little, you know, newer for B.C.*
>
> *…So I want to assure you there is a lot of activity underway today and we're not waiting for the electrification plan or Fiscal '23 to get going and really quite excited by the prospects here."*

The CEABC appreciates these words of assurance and expects that they will continue to be acted upon so the CleanBC Rates are fully subscribed as soon as possible. As indicated under the heading "A. Electrification of the Montney Oil and Gas Fields" domestic sales of electricity will result in more revenue to BCH, and reduced GHG emissions in the Province than export sales.

The CEABC also expects that the large pipeline of projects referenced above will be included in BCH's next integrated resource plan which will be filed by the end of December 2021 ("December IRP") and in the five year[24] electrification plan ("Electrification Plan") that BCH is bringing forward in the next revenue requirement application that is expected to be filed In August 2021("August RRA"). In this respect BCH committed to:[25]

> *"To bring all this together, we are working on an overall electrification plan which will be part of the next revenue requirements application. It will cover our existing electrification efforts from across the company as well as our plans for additional actions to help drive an increased electrification. We will be hosting engagement workshops over the next couple of months to ensure customers and interveners have input into the type of electrification opportunities and barriers that exist and actions BC Hydro can take to help overcome those barriers."*

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[23] Transcript, Vol. 1, page 214
[24] Ibid, page 209
[25] Ibid, page 39

It is critical that this Electrification Plan be incorporated into the December IRP.[26] Since this IRP will follow the August RRA, the implementation of the December IRP will, assuming a two-year test period for the August RRA, be delayed until Fiscal 2025. If this test period is extended to three years, the delay will extend to Fiscal 2026. CEABC recommends that BCH change its decision to exclude the Electrification Plan from the December IRP and that the test period for August RRA be limited to one or two years.

## 6) Electrification of the Montney Oil and Gas Fields.

Whether Puget Sound Energy's or BCH's Mid-C price forecast is the most accurate[27], it is clear that in order to increase revenue and reduce greenhouse gas emissions in the Province, BC Hydro should be making every effort to increase electricity sales to the oil and gas sector in the Montney Region of northeast B.C. ("Montney"). After subtracting U.S. wheeling charges and losses from Powerex's sales of surplus BCH generated electricity at Mid-C, the net revenue to Powerex from these sales is substantially less than if BCH sold the same electricity in accordance with its domestic tariffs including the recently announced CleanBC Industrial Electricity Rate.

In addition to U.S. transmission losses, exports of electricity generated by BCH's GM Shrum and Peace Canyon projects ("Peace Projects") result in average domestic transmission losses of approximately 11% to the U.S. border.[28] This additional loss could be avoided by selling the same surplus electricity to the Oil and Gas industry in the Montney Region, which is in very close proximity to the Peace Projects and independent power producer wind projects in this region.

The following is a sample calculation that can be found in the BCUC Inquiry Respecting Site C – Final Report[29] that illustrates the potential reduction in revenue from Mid-C sales because of losses on both sides of the border and U.S. wheeling charges:

> *"This results in a Mid-C Market Price of (F2018) CAD $32/MWh in 2018 with real escalations to (F2018) CAD $55/MWh in 2040. Approximately the Mid-C Market Price rises each year by CAD $1/MWh in real terms. After adjusting for line losses at 1.9 percent, wheeling at CAD $6.3/MWh, <u>and</u> <u>transmission</u> <u>losses</u> <u>to</u> <u>Site</u> <u>C</u> <u>at</u> <u>11</u> <u>percent</u>, the market price for energy surplus is (F2018) CAD $22.3/MWh in 2018. The market price for energy surplus rises to (F2018) CAD $42.4/MWh in 2040."* [emphasis added]

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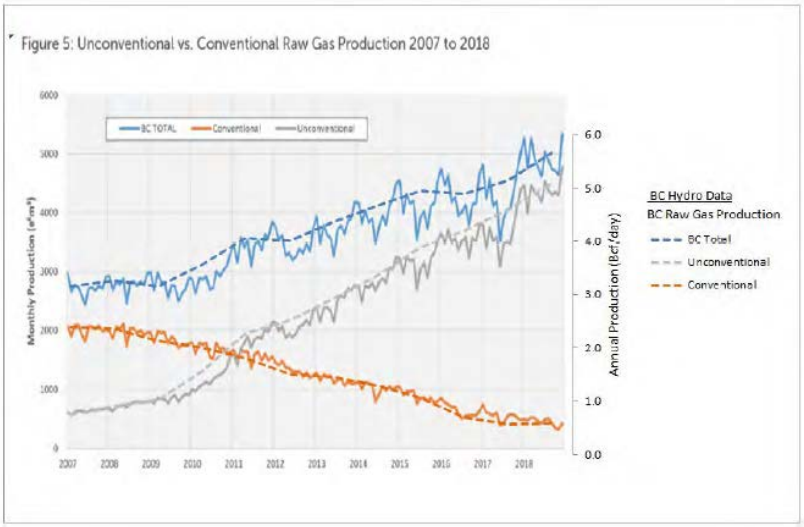
[26] Transcript Vol. 1, page 209
[27] Exhibit B-5, BCH response to CEABC IR 1.8.4.1
[28] The same loss factor would apply to electricity generated at Site C
[29] Page 160

This example is illustrative and is not being presented as a definitive calculation of the price BCH would actually receive in all instances of sales of electricity generated by Peace Projects and sold at Mid-C.

For over 5 years, the CEABC has been recommending the need to electrify the Montney in BCUC proceedings involving BCH.[30] Increased electricity sales in the Montney will not happen unless BCH expands its transmission system and accelerates the timelines for interconnecting gas production facilities.

Historically, it is an area of B.C. that has had a rudimentary transmission system. The oil and gas industry did not need much electricity or wellhead gas to remove the impurities from "dry" gas. The following graph[31] shows the switch from dry to liquids-rich gas production in the Province and the total increase in overall gas production.




The energy requirements of producing liquids rich gas are markedly higher than producing dry gas[32] with the choices being wellhead gas or renewable electricity. The combustion of the former will increase GHGs. The Navius Report[33] provides an estimate of a 5,600 GWh in load growth for the oil and gas subsector load, with most of the growth occurring before 2030.

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[30] E.g., CEABC Amended Final Submission, June 15, 2017, BCH F2017-F2019 BCH RRA Application, , pages 13-26

[31] Exhibit B-5, BCH response to CEABC IR 1.5.1

[32] CEABC Amended Final Submission, June 15, 2017, BCH F2017-F2019 BCH RRA Application, pages 20-22

[33] Entitled: "British Columbia Electrification Impacts Study: Forecasting the Impact of Achieving British Columbia's Greenhouse Gas Emissions Targets on Provincial Electricity Consumption" and see Exhibit B-5, BCH responses to CEABC IR1.1.7

The very recently announced[34] Provincial GHG reduction sectoral targets include a target reduction in GHG emissions of 33 to 38% from 2007 sector emissions for the oil and gas industry. More evidence of the need to electrify the Montney.

The CEABC supports BCH's efforts to increase the electrification of the Montney through the expansion of its transmission system including the:

- Dawson Creek Area Transmission project or DCAT
- Fort St. John and Taylor Electricity Supply Project energized in December 2020[35]
- Peace Region Electricity Supply Project (PRES), to be energized in May 2021[36]

The expansion of the transmission system into the north Montney is still a work in progress. When asked about this expansion in the Web-Based Session BCH responded:[37]

> *"So we've actually started our prelaunch for the North Montney expression of interest, if you will, which is really just making sure that customers, land holders, associations, are aware that we will be running an expression of interest process and expect that sometime –we're hoping anyway that sometime later in March, early April we'll be able to move into our expression. And so that initial step is conceived as kind of one of three steps where we would be going out and initially assessing, you know, interest from customers if BC Hydro were to build that line.*
>
> *The first expression of interest stage, if we see that there is sufficient interest, then we would continue moving forward with work on – you know, the technical work on the line as well as our work with the province and the federal government to see if we can secure up to 50 percent funding for the line, and ultimately move then into what we're calling a phase 2 and a phase 3 where we could get continued and increased level of commitment from those customers to building a line.*
>
> *… I think it's a little too early in the project to give an end-state estimate. We know that customers are asking for 2026 if they had their druthers."*

For the Province to meet the GHG reduction targets in the Climate Change Accountability Act, as allocated in the newly announced sector emissions targets for the oil and gas industry, a North Montney transmission line will be a critical piece of infrastructure. BCH should do everything possible during the Test Period to expedite the development of this line. Although its construction will not start during this period, an in-service date of 2026 will be pushed further into the future and potential customers lost if early work is not undertaken in an expeditious manner.

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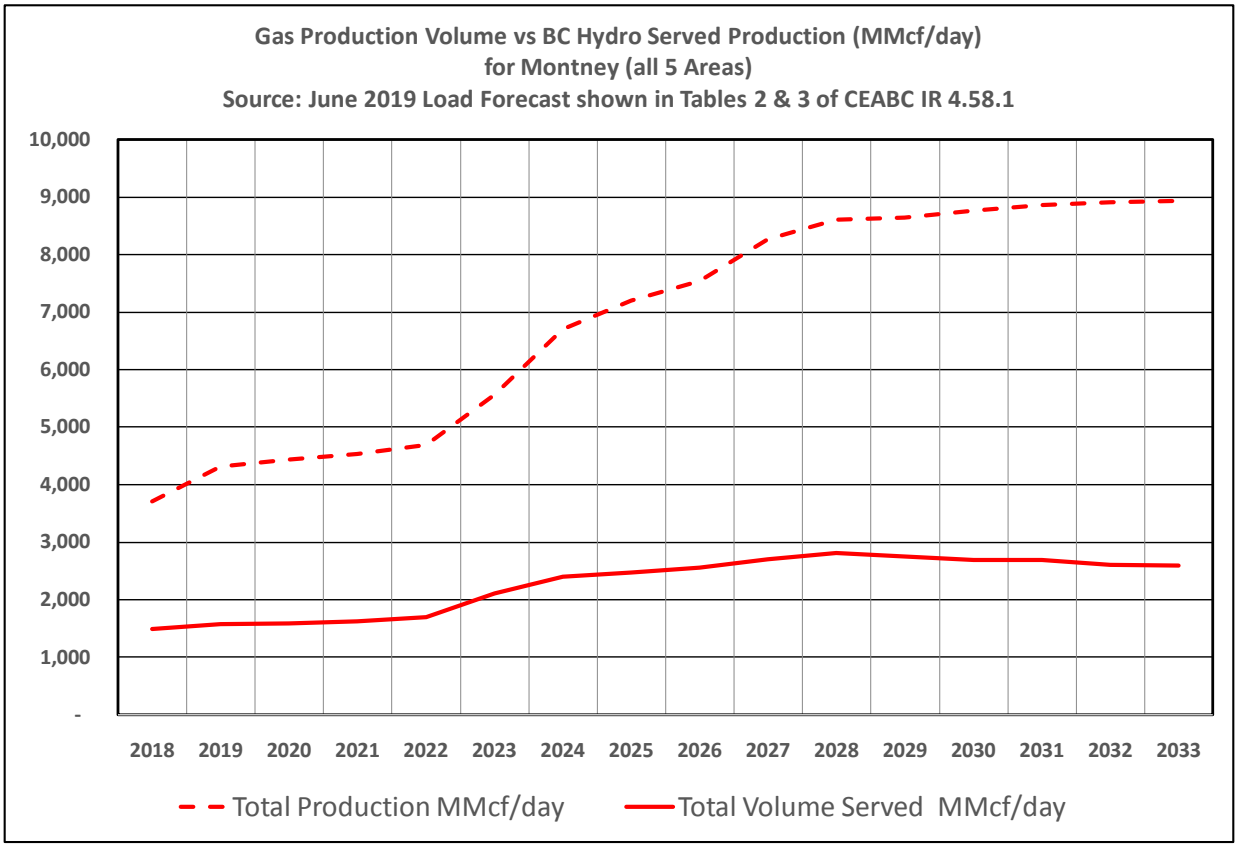
[34] https://news.gov.bc.ca/releases/2021ENV0022-000561

[35] Exhibit B-5, BCH response to CEC IR 1.39.2.1

[36] Ibid

[37] Transcript, V1 pages 225-226

The CEABC's F2020-F2021 Revenue Requirement Final Argument contains the graph below [38] that shows the gap between expected gas production in the Montney and the amount of this production that is expected to be served by electricity.




While it is important that BCH build transmission lines in the Montney, it is equally important that BCH actively market its renewable electricity as the replacement to the traditional sources of wellhead and pipeline gas that the oil and gas industry has used to meet its energy requirements. This includes dedicating time and resources similar to its Power Smart initiatives[39] to close the gap between expected gas production in the Montney and the amount of this production that is expected to be served by electricity. It should also be actively marketing government programs such as the CleanBC Industry Fund to the oil and gas industry with respect to the use of renewable electricity to reduce GHG emissions.

# III. CONCLUSIONS

CEABC recaps its key observations and recommendations regarding the selected issues discussed above.

[38] Page 41
[39] As adjusted for scale

**1) The use of the March 2020 Load Forecast, and the use of "Scenario A" to adjust for the impacts of the Covid-19 pandemic.**

- CEABC accepts that the Scenario A adjustments, as designed by BC Hydro, appear to reasonably reflect the impacts of the Covid-19 pandemic on the loads in F2021, in so far as was feasible prior to the submission of the Application. It remains to be seen how far into the future the pandemic will continue to impact electricity loads.
- CEABC is concerned that both adjustment scenarios are predicting a persistent reduction of about 1%, extending to F2024 and F2025. However, this reduction is all confined to the Large Industrial sector, where it constitutes almost a 5% reduction. This is a very significant predicted reduction and CEABC suggests that it should be thoroughly examined in the next RRA.
- CEABC is also concerned that the March 2020 Load Forecast used for this Application excludes much of the necessary electrification loads required to achieve the GHG reduction goals targeted by the Government in its CleanBC Plan. BC Hydro's consultant, Navius, projects that this additional load could amount to over 15,000 GWh by 2030. Although this omission may not impinge severely on the immediate 1-year test period being used for this F2022 RRA, this shortcoming should be remedied as soon as possible, and be included as part of the Reference Case in any future plans and RRAs.

**2) The impact of successful Demand Side Management on BC Hydro's rates**

- CEABC has frequently pointed out that the conventional metrics used to measure the effectiveness of DSM measures (namely, the Total Resource Cost and the Utility Cost metrics), do not assess the impact of those measures on the general rate levels the utility has to charge – principally because they do not consider the impact of the lost billing revenues, which can very well exceed all the utility's savings. The only metric that assesses this impact is the Ratepayer Impact Measure (RIM) test.
- BC Hydro's recalculation of the RIM Benefit/Cost ratios, using realistic values for the "saved" energy shows that the costs to ratepayers, of the entire DSM portfolio savings, over the period from F2019 to F2023, will amount to roughly 3 times the value of the benefits, which could amount to a present value burden on ratepayers of approximately $550 million.
- In view of these findings, CEABC agrees with BC Hydro that a moderation strategy with respect to DSM measures is entirely appropriate, and CEABC encourages BC Hydro to pursue cost effective electrification as broadly and rapidly as possible, as a means to remarket the "saved" energy and thereby mitigate the upward pressure on its rates.

**3) The need for an EV Costs Regulatory Account and the accounting for electrification initiatives in general**

- CEABC finds that BC Hydro's proposed approach to its EV Station charging business is overly complex, involving costs and revenues flowing through a number of different regulatory accounts, and will not facilitate the transparent evaluation of EV charging as an operational business entity.
- CEABC recommends a simplified 5-point accounting treatment that should facilitate better overall visibility for the business unit.
- CEABC also asserts that deferral account treatment can be avoided in the case of EV charging, and for the electrification initiatives, in general, for two reasons:
  - The outcomes are not entirely out of the control of BC Hydro management.
  - When the forecast loads and revenues are set to achieve the CleanBC GHG reduction targets, the potential for gains or losses vs. the forecast will likely be asymmetrical. Therefore, the chances that the ratepayers will miss out on potential gains are much less than the chances that they will be protected from potential losses.

**4) Transfer of EV credits to Powerex**

- CEABC is concerned that transferring these credits to Powerex obscures any visible means of tracking their value. A similar situation occurs when BC Hydro markets the RECs it obtains from IPP electricity. The CEABC recommends that the Transfer Pricing Agreement be amended to include the sale of Credits, RECs or similar products ("Products") and that amendments include a mechanism for visibly tracking the value of the Products sold. Alternatively, that all transfers of Products from BCH to Powerex be recorded by separate agreements that include a mechanism for tracking the value of the Products sold.

**5) CleanBC Industrial Electrification Rates (RS 1894 and 1895)**

- CEABC appreciates BC Hydro's words of assurance and expects they will continue to be acted upon so the CleanBC Rates are fully subscribed as soon as possible.
- The CEABC also expects that the large pipeline of projects referenced by BC Hydro will be included in BCH's next integrated resource plan which will be filed by the end of December 2021 and in the five year Electrification Plan that BCH

is bringing forward in the next revenue requirement application, expected to be filed In August 2021, as committed to by BC Hydro.

- It is critical that this Electrification Plan be incorporated into the December IRP, since its implementation will follow the August RRA and thereby be delayed until Fiscal 2025 (or longer, if the August RRA extends the test period to three years).

## 6) Electrification of the Montney Oil and Gas Fields

- BC Hydro's Navius Report provides an estimate of a 5,600 GWh in load growth for the oil and gas subsector load, with most of the growth occurring before 2030. CEABC is concerned that increased electricity sales in the Montney will not happen unless BCH expands its transmission system and accelerates the timelines for interconnecting gas production facilities.
- The CEABC supports BCH's efforts to increase the electrification of the Montney through the expansion of its transmission system, including DCAT, Fort St. John and Taylor, and PRES.
- However, the expansion of the transmission system into the North Montney is still a work in progress. For the Province to meet the GHG reduction targets in the Climate Change Accountability Act, as allocated in the newly announced sector emissions targets for the oil and gas industry, a North Montney transmission line will be a critical piece of infrastructure.
- Although its construction will not start during this Test Period, BCH should do everything possible during this period to expedite the development of this line.
- As pointed out in CEABC's F2020-F2021 Revenue Requirement Final Argument, there is a considerable gap between expected gas production in the Montney and the amount of this production that is expected to be served by electricity. CEABC urges BC Hydro to actively market its renewable electricity as the replacement to the traditional sources of wellhead and pipeline gas that the oil and gas industry has used to meet its energy requirements. This includes dedicating time and resources to actively market electricity in a manner similar to its Power Smart initiatives, in order to close the gap between expected gas production in and the amount of this production that is expected to be served by electricity

All of which is respectfully submitted.

April 6, 2021

Clean Energy Association of B.C.