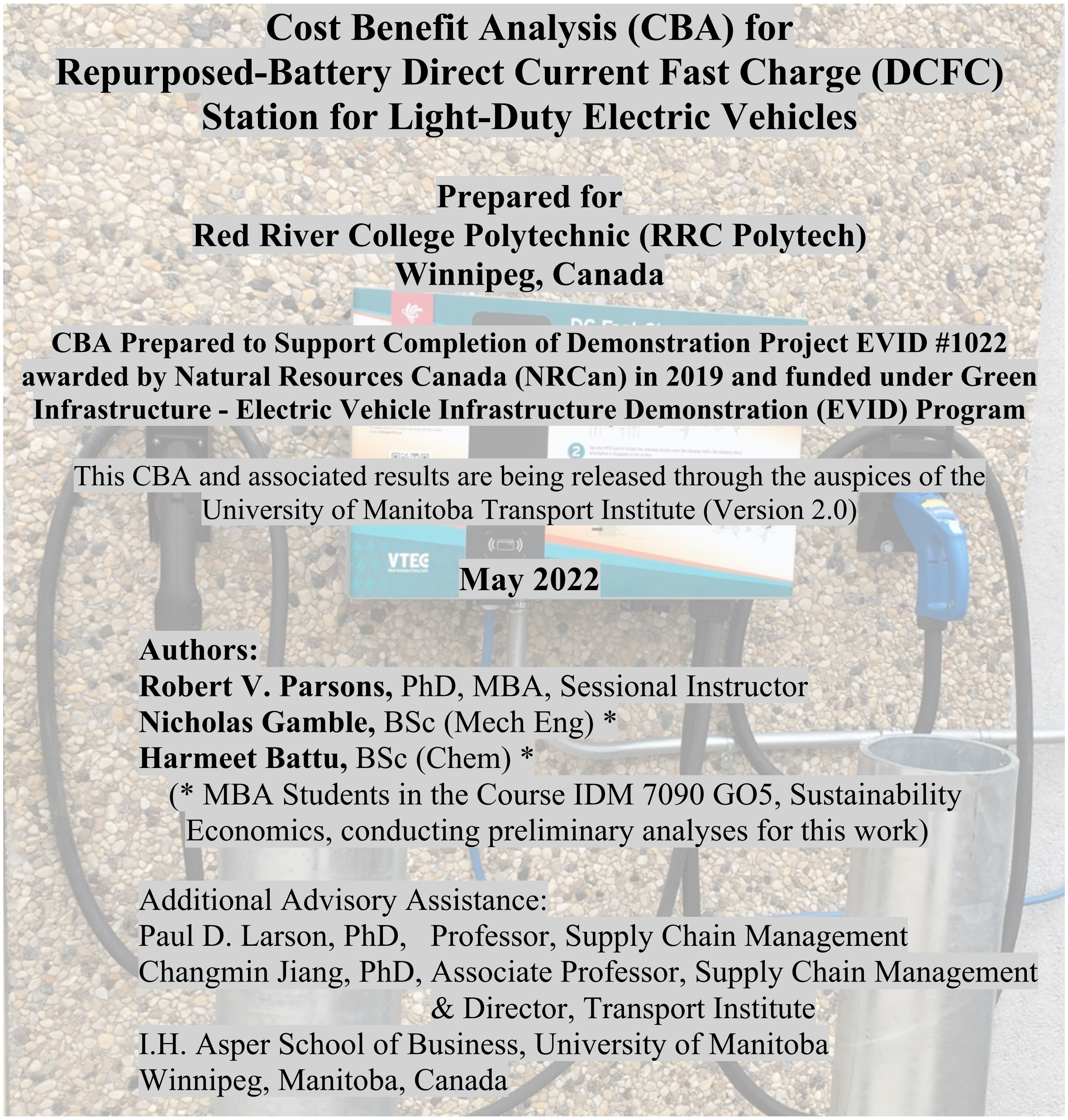

Cost Benefit Analysis (CBA) for Repurposed-Battery Direct Current Fast Charge (DCFC) Station for Light-Duty Electric Vehicles

Prepared for
Red River College Polytechnic (RRC Polytech)
Winnipeg, Canada

CBA Prepared to Support Completion of Demonstration Project EVID #1022 awarded by Natural Resources Canada (NRCan) in 2019 and funded under Green Infrastructure - Electric Vehicle Infrastructure Demonstration (EVID) Program

This CBA and associated results are being released through the auspices of the University of Manitoba Transport Institute (Version 2.0)

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Summary

Red River College Polytechnic (**RRC Polytech**), which is Manitoba's largest post-secondary polytechnic institution, centred in Winnipeg, submitted a proposal to Natural Resources Canada (**NRCan**) for a novel demonstration project on electric vehicle charging infrastructure. The demonstration project, designated as EVID #1022, is officially entitled "Demonstration of Repurposing of Already-Used, Large-Format Heavy-Duty Transit Bus Batteries for Electric Vehicle Rapid Charging." The proposal was successful and was awarded funding in 2019.

This report provides a cost-benefit analysis (**CBA**) for the resulting rapid charging system constructed and operated in Winnipeg. In abbreviated form, the project is known as the **B2U** (standing for Battery 2nd Use) direct-current fast charge **(DCFC)** system. The intent of this report is to estimate, evaluate and present the economic business case for the system, including environmental benefits and costs, in order to confirm viability and determine applicability of the novel approach for replication elsewhere.

Novelty of B2U DCFC

The genesis of the project stems from RRC Polytech's extensive experience. This includes involvement with electric vehicles and their batteries, especially heavy-duty transit buses, and with electric vehicle charging systems. The incorporation and use of batteries as part of electric vehicle charging stations has emerged as an advantageous approach, mitigating electrical-grid impacts and reducing electrical demand fees. These advantages have been well recognized, for example by prominent organizations like McKinsey.

Further, the incorporation of already-used batteries in such applications is conceptually positive both economically and environmentally. Most obviously, the cost of batteries is reduced, directly improving economic viability. Secondly, repurposing of batteries leads to reduced environmental impacts associated with both having to make new batteries and having to dispose of older batteries. Electric vehicles still represent a very small proportion across Canada and around the world. With anticipated numbers continuing to rapidly climb, though, the numbers of batteries reaching end-of-life for suitability in electric vehicles will steadily mount too, and will need to be addressed. Repurposing represents one appropriate mitigation approach.

The exterior charging points for the B2U DCFC are shown in Figure 1, with an electric vehicle engaged in a charging event. The system, as implemented, is described in more detail in the report, but includes the following key highlights:

- Maximum vehicle charging rate of 25 kW, with practical delivery of 23 kWh in one hour;
- Maximum allowed charging event for 60 minutes, with practical ability to deliver approximately seven such charge events within a given daily period (12 hours);
- Battery storage capacity of 50 kWh, with anticipated usable lifespan of 10 years; and
- Battery charging rate (from building) of approximately 11 kW (or 11 kWh per hour).

All of the batteries are from NFI Group (New Flyer), specifically from battery electric buses (**BEB**). All were employed in demonstration activities dating back to 2014, roughly eight years

ago, and involved extensive-use. All batteries were originally produced by the U.S. manufacturer Xalt Energy, and involve, in general terms, lithium-nickel-manganese-cobalt (**NMC**) chemistry, but with specifics not known.

Economic Benefits of B2U DCFC

There are two potential economic benefits associated with the B2U DCFC: firstly, reduced capital costs associated with initial implementation; and secondly, reduced demand-fee costs associated with operations.

Capital costs are estimated for the B2U DCFC, as well as multiple comparable system options, all installed in connection with an existing building. Seven options are summarized as follows:

- Existing B2U DCFC system, based on the unit as constructed and proven through demonstration, with cost of approximately **$35,000**;
- Improved B2U DCFC system, based on identified simplifications and improvements, although not yet implemented, with cost of approximately **$22,500**;
- New-battery DCFC system, identical to the unit as constructed except employing new batteries rather than repurposed batteries, with cost of approximately **$47,000**;
- Improved New-battery DCFC system, incorporating the same simplifications and improvements as above, except employing new batteries rather than repurposed batteries, with cost of approximately **$34,500**;
- Grid-based DCFC with power level of 25-kW, most closely comparable to the B2U DCFC, with cost of approximately **$30,000**;
- Grid-based DCFC with power level of 60-kW, roughly twice the power level of the B2U DCFC, with cost of approximately **$100,000**; and
- Grid-based DCFC with power level of 120-kW, roughly four-times the level of the B2U DCFC, with cost of approximately **$150,000**.

The capital cost of the existing B2U DCFC is seen to be relatively comparable to or lower than other options to provide electricity to vehicles at a power level around 25-kW. The B2U DCFC also shows significantly lower capital costs than higher power-level grid-based systems.

Monthly-costs are also estimated for the above seven options, based on operation within Manitoba and installed in connection with an existing building. Costs include monthly coverage for capital, demand fees, and energy fees assuming 5% station utilization per month, which is currently realistic. Results for the same seven options are summarized as follows for Manitoba:

- Existing B2U DCFC system, based on the unit as constructed and proven through demonstration, with monthly-costs of approximately **$524**;
- Improved B2U DCFC system, based on identified simplifications and improvements, although not yet implemented, with monthly-costs of approximately **$389**;
- New-battery DCFC system, identical to the unit as constructed except employing new batteries rather than repurposed batteries, with monthly-costs of approximately **$654**;

- Improved New-battery DCFC system, incorporating the same simplifications and improvements as above, except employing new batteries rather than repurposed batteries, with monthly-costs of approximately **$518**;
- Grid-based DCFC with power level of 25-kW, most closely comparable to the B2U DCFC, with monthly-costs of approximately **$631**;
- Grid-based DCFC with power level of 60-kW, roughly twice the power level of the B2U DCFC, with monthly-costs of approximately **$2,634**; and
- Grid-based DCFC with power level of 120-kW, roughly four-times the level of the B2U DCFC, with monthly-costs of approximately **$4,286**.

The results within Manitoba show very positive results for the current B2U DCFC with significant savings compared to more-conventional grid-based systems. The results considering the most-comparable grid-based system, of 25-kW, show monthly savings of approximately 17%, meaning application of the B2U DCFC system already makes sense, with viability further improved if identified simplifications can be implemented. The results also point out the extremely high costs associated with the convenience of higher-power, grid-based DCFC systems, with: 60-kW system being at least 5× more expensive per month, while only providing a power level about 2× higher; and 120-kW system being at least 8× more expensive per month, while only providing a power level about 4× higher. Cost data are also developed for the option of a stand-alone, containerized B2U DCFC within Manitoba; more detailed information is presented in this report showing roughly comparable relative savings.

A final important economic aspect is considering differences in electrical utility tariff rate structures between different jurisdictions. Demand fees and energy fees vary substantially across Canada, with demand fees appearing crucial in determining the economic viability of the B2U system, while electrical energy fees appear relatively unimportant.

- Jurisdictions having utilities with consistent and relatively-higher demand fees, such as **Manitoba** and **Nova Scotia**, show the highest monthly savings for the B2U system, with Manitoba indeed showing the best viability within Canada as a whole.
- Jurisdictions having utilities with consistent and relatively lower demand fees, such as **BC**, show some savings but much lower, and thus much less attractive.
- Jurisdictions having utilities with variable demand fees, including **New Brunswick**, **Saskatchewan** and **Quebec**, with these also typically involving some threshold level below which demand fees are not levied, represent the least beneficial applications for the B2U system, with some provinces, such as Saskatchewan and Quebec, even appearing to show the B2U system to have appreciably higher monthly-costs than a grid-based system.

Based on data across the above six jurisdictions, an effective "break-even demand fee" can be estimated in order for the existing B2U DCFC system to match the 25-kW grid-based system. This break-even value within Canada corresponds to approximately $4.50 per kVA per month. Given this situation, careful evaluations of the details of demand fee structures are required in each individual province in order to confirm whether or not the B2U system could offer benefits.

Environmental and Social Externality Benefits of B2U DCFC

Electric vehicles of all types incorporate on-board battery-based storage of electricity obtained from local electric-grids, then used to power motive operations. All of these vehicles thus involve significant reductions in the use of and the reliance on conventional fossil fuels, whether gasoline or diesel, respectively. While often dubbed “zero-emission,” it is also well-acknowledged that such vehicles can still lead to adverse implications, both environmental and social. The nature of identified negative implications of electric vehicles, primarily, has related to the greenhouse gas (**GHG**) intensity of local electricity grids used to power them. At the same time, secondary yet still important impacts, relate to their batteries and various implications associated with battery manufacturing and disposal. The latter provide the direct connection to estimating externality benefits for the B2U DCFC.

Various externality benefits can be identified as relevant to consider, however, not all can be readily monetized at this time. Likely the most important concerns not readily monetized relate to social and human problems with the extraction of cobalt metal in developing countries, as discussed in more detail. Two specific externality benefits have been monetized in this report:

- First involves benefits associated with avoided GHG emissions from the manufacture of a new functional battery of the same capacity; and
- Second involves benefits associated with avoided GHG emissions and lithium-metal losses from the smelting of the battery for recovery of cobalt if not repurposed.

Of these two, the second is the largest, but both combined are still not large, on a monthly-basis representing only about $7.00. While relatively small, this value is notable considering the 25-kW grid-based station, for which externality benefits amount to approximately 6% of savings.

Follow-Up and Further Demonstration for B2U DCFC Technology

RRC Polytech’s current priority is to complete remaining monitoring activities for the B2U system over the remaining period of the project. This is in order to better confirm the system’s technical functionality and suitability over multiple years of operation, and to fulfill commitments to NRCan as part of funding responsibilities. Further suggested activities include:

- Maintaining the existing B2U system in place operationally for an extended period after formal project completion, i.e., for as long as may be reasonable, in order to maximize value, profile and relevant data from the system. This includes, if possible, much longer operation to physically confirm the lifespan of the repurposed batteries.
- Considering further options for the existing B2U system, in particular alternative sites to better assess operational suitability for other types of locations (including identifying additional modifications or enhancements that may be worthwhile for such installations). Two types of locations are identified for this purpose: tertiary-care hospitals, with St. Boniface Hospital specifically identified; and big-box-mall retail store sites. Also note that moving the system but maintaining it in operation would still permit assessing physical lifespan of repurposed batteries.

- Considering the assembly and implementation of an upgraded version of the B2U system, as long as suitable funding can be located, involving the lower-cost simplifications as outlined, this in order to confirm operational functionality, and associated economic advantages.
- Continuing discussions with NFI Group regarding availability and repurposing of further used BEB batteries, and how such arrangements could transition over the longer term into a business solution for NFI that can provide them sustained competitive advantage in the transit bus manufacturing industry.
- Emphasizing growth in local expertise and competency in the unique niche area of battery repurposing, including building towards possible development of a mini-industrial-cluster, and emphasize RRC Polytech's increasing prominence in this field, in particular as a central organization for any mini-industrial-cluster.
- Beginning to identify and explore pathways for more-commercial application of the B2U technology, possibly including some sort of start-up company or industrial partner.
- Initiating discussions with other vehicle manufacturers, in particular heavy-duty vehicle manufacturers, regarding access to additional types of already-used vehicle batteries.
- Beginning work with neighbouring provinces and associated collaborators as a logical follow-on for the B2U system, in particular given RRC Polytech's recent leadership and increased profile on regional-wide electric vehicle charging infrastructure enhancement.

Figure 1. Exterior vehicle plug-points for B2U DCFC system at RRC Polytech showing an electric vehicle connected and charging. (R. Parsons 2022).

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(Cover photo: Repurposed Battery-based (B2U) DCFC System at RRC Polytech in Winnipeg, showing Combined Charging System (SAE) and CHAdeMO charging points, R. Parsons 2022)

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1.0 Project Background

1.1 Applied Research at RRC Polytech

Red River College Polytechnic (**RRC Polytech**) is Manitoba's largest post-secondary polytechnic institution, and for more than 15 years has been undertaking important applied research activities, these through its Research Partnerships & Innovation (**RPI**) department. Indeed, over the past five years, RRC Polytech has ranked consistently within the top 15 of Canada's Top 50 Research Colleges (Research InfoSource 2022).

One major applied research area relates to vehicle fuels and technologies, especially involving advanced battery-based and other zero-emission vehicle technologies, now coordinated through their Vehicle Technology and Energy Centre (**VTEC**) initiative. Past activities include support for the international consortium on prototype electric transit bus development and demonstration in Manitoba (Hoemsen 2017), the first of its kind in Canada, as well as a host of further projects and applied research that have followed.

A particular niche of expertise that RRC Polytech has been pursuing is how to appropriately repurpose already-used, large-format lithium-ion batteries from heavy-duty battery electric buses (**BEB**). One major recent application in this vein was repurposing of used-batteries to electrify a specialized heavy-duty Tundra Buggy used by Frontiers North Adventures for its "polar bear tours" in the vicinity of Churchill, Manitoba (Cash 2021). A second major application is reuse of batteries for the charging of light-duty electric vehicles, in particular battery electric vehicles (**BEV**), the subject of this analysis.

1.2 Battery Repurposing Demonstration Project

Starting in 2017 through 2018, RRC Polytech successfully submitted an "expression-of-interest" to Natural Resources Canada (**NRCan**) through a multi-step competitive process to the Green Infrastructure - Electric Vehicle Infrastructure Demonstration (**EVID**) program (NRCan 2021a). A more-detailed subsequent proposal was then submitted and successfully awarded. The project, designated as demonstration project EVID #1022, is officially entitled "Demonstration of Repurposing of Already-Used, Large-Format Heavy-Duty Transit Bus Batteries for Electric Vehicle Rapid Charging." Funding for this project and official kick-off were announced on August 12, 2019 (RRC Polytech 2019). The shortened name reference used is the "**B2U**" project (RRC Polytech 2022).

The project involves multi-year operation, and is still currently underway, with a few technical monitoring activities not quite completed. NRCan (2021b) maintains an internet page describing the project, which is noted as a "current investment," and summarizing key details. The overall objective of the project is described as to implement, operate, monitor and evaluate a functional direct current, fast charge (or **DCFC**), sometimes also referred to as a **Level 3**-equivalent charging station, for light-duty electric vehicle charging station at RRC Polytech, based on used-batteries taken from battery-electric transit buses that have been operated for an extended period. As such, this novel project is the first of its kind in Canada, and one of the first such in the world. The system set-up behind the charging point is illustrated in Figure 2.

Figure 2. Battery energy storage system (BESS) set-up inside CARSI Building for the B2U at RRC Polytech, Notre Dame Campus, Winnipeg (R. Parsons 2022).

Anticipated results of the project, as outlined, include: improve performance of rapid charging stations by using more efficient battery-to-battery energy transfers; reduce costs of rapid charging stations, through the use of lower-cost used batteries; improve cold-weather related rapid charging performance; and achieve environmental improvements through the use of recycled, mildly-degraded batteries, allowing for the repurposing of old materials. Importantly, the evaluation component of the project, as outlined, includes economic analysis.

RRC Polytech is developing more detailed final reporting, including technical documentation on the performance of the completed system. One key component of the project, as required for the EVID program, is to advance the Technology Readiness Level (**TRL**) of the system significantly toward becoming commercially ready, with this evaluation approach outlined by Industry Canada (2018). The intended beginning and end point statuses are summarized as follows:

- Anticipated **TRL #5** at start of project, which means that system components are all readily operational and are integrated, but not yet operated together at scale or under real-world conditions; and
- Anticipated **TRL #8** by end of project, which means that a prototype has been operated at full-scale in a real-world operational environment.

The **TRL #9** level is typically denoted as representing a fully-ready technology, applicable for use in commercial markets. One important aspect of such TRL evaluation, however, is that readiness means just that, and does not necessarily translate to economic effectiveness, nor, on its own, imply economic viability. Based on TRL advancement through the course of the demonstration project, there is sufficient information available to allow preparation of a cost benefit analysis, which, as noted, is an important component project activity.

Importantly, the current project through RRC Polytech is known to be not the first grid-based energy storage within Manitoba involving already-used batteries. Earlier, in 2010, Manitoba Hydro International participated in a major project involving lithium-ion battery manufacturer Electrovaya and coordinated through CEATI International. Manitoba Hydro's subsidiary implemented systems to evaluate and test repurposed automotive battery packs to evaluate suitability as battery energy storage systems (BESS) for electrical utilities. Unfortunately, no public-report appears available any longer for this project, but the project is still identified by NRCan (2010). RRC Polytech's work thus continues to build local expertise in this unique area.

1.3 Purpose of Report

The intent of this report is to estimate, evaluate and present the economic business case for the system, including environmental benefits and costs, and to present information in the form of a cost-benefit analysis (**CBA**). The intended outcome is thus to determine and potentially confirm applicability of the novel approach for further replication elsewhere.

1.4 Economic and Sustainability Aspects Included

The use of a repurposed-battery B2U DCFC station offers three important component advantages that are each included for the evaluation in this report:

- Direct economic savings by virtue of likely lower capital and/or operating costs compared to conventional grid-connected DCFC systems;
- Sustainability-based externality savings by virtue of repurposing and extending the lives of batteries, thus obviating requirements for new materials, associated inputs, disposal costs, and problematic social conditions; and
- New charging-site introduction opportunities.

The third aspect involves somewhat unique advantages in certain circumstances. As discussed, conventional grid-connected DCFC technologies are expensive, and involve components that can be relatively short-lived, increasing costs. As such, it is desirable and important to ensure selected-sites for stations are indeed viable and will be adequately employed. This perspective is reiterated in a recent report on early lessons-learned with DCFC systems by Nicholas and Hall (2018) for the International Council on Clean Transportation (ICCT):

- Great uncertainty in extent of rapid charging actually required in the future, with priority charging locations being firstly home-based, and secondly workplace-based;
- Rapid charging requirements most important to enable longer-distance intercity travel, with rapid charging within urban areas suitable primarily for emergency top-ups and to service so-called “garage orphan” vehicles without an established home charging point;
- Higher initial proportion required for rapid charging of about 1 DCFC per 100 BEV, to ensure potential infrastructure gaps are adequately covered, but gradually declining as overall capabilities extend to only about 1 DCFC per 700 BEV; and
- Significant increase in the number of rapid charging stations required as electric vehicle up-take increases, but with the proportional increase in charging stations much lower than the proportional increase in electric vehicle sales.

Currently, within Winnipeg there are as estimated 15 DCFC in place (Charge Hub 2022). At first glance this appears thus more than adequate already to service electric vehicles within Manitoba, with a current estimate of about 800 BEV in the province (Gardiner 2021). However, the suitability and utilization depend critically on location.

A B2U DCFC system offers a way to more-quickly and more-flexibly implement a DCFC at a newly identified site in a way that is economically more attractive overall. This is because of both the readily movable nature, if containerized, and the potentially lower costs of the system, as long as daily vehicle charging does not become overwhelming. This allows the ability to qualify and confirm suitability of a given site for longer-term use, leading in stages to implementation of a more-expensive permanent station where warranted. As a given site begins to be used beyond the realistic capacity of a B2U DCFC station, it becomes easier to then economically justify a more expensive, permanent system that is grid-connected.

FleetCarma (ND) in the past prepared a useful brief document regarding important practical considerations in the siting of rapid-charging stations. A cursory review of literature on DCFC site selection, however, shows an apparent overemphasis on demand forecasting techniques and sophisticated computer algorithms, but less on actual prior verification. Recent literature such as Ahmad et al. (2022) and Zhou et al. (2022), illustrate the trend to strongly emphasizing computer modeling and sophisticated algorithms. The use of the B2U DCFC approach, on the other hand, can allow for verification in practice of site suitability.

2.0 Bases for Economic Calculations

2.1 B2U Station Specifications and Capital Costs (Building-Connected)

The applied-research team at RRC Polytech has completed implementation of the B2U DCFC system in a way that is already now workable, but with still some obvious optimization and simplification possibilities. RRC Polytech (2022) also maintains an internet site describing the layout and components involved with the operational system, including on-line current state-of-charge (**SOC**) status indication. The "nameplate" specifications of the B2U DCFC system are summarized in Table 1.

Table 1: Nameplate Specifications of B2U DCFC System for EV Charging

Parameter	**Value**
Maximum vehicle charging rate (max)	25 kW (with 23 kWh delivered per hour)
Battery storage capacity	50 kWh
Maximum station charging rate (input)	11 kW (or 11 kWh received per hour)
Maximum allowable charging event	60 minutes maximum allowable *
Anticipated lifespan	10 years useable operation

* Limit is intended to prevent individuals from abusing charging spots for free parking

DCFC involve non-linear response that needs to be considered for operations (Jadav 2015). Given non-linearity, the practical charging rate based on experience for a battery-based system translates to approximately 23 kW or maximum hourly delivery per vehicle thus 23 kWh. Based on typical electric vehicle consumption, ranging from about 18 to 22 kWh per 100 km, such charging translates to added travel distance of 110 to 130 km. This power delivery level is thus certainly a suitable for DCFC within urban areas, adequately reflecting needs for more-emergency or top-up situation. The result in this case may be less desirable for inter-city travel situations, where a charging level of about 50 kW may be more appropriate. Consideration has been given for a larger nameplate capacity system, say 50 kW to 60 kW, and may be considered further on, but not as part of the current project.

The major components of the station, as implemented, are summarized as follows:

- Connection to the grid (**AC**);
- Battery charging unit, converting AC to direct current (**DC**) power for top-up and storage in the battery, with a charging-rate capability of 11 kW;
- Battery pack, which essentially operates as a battery energy storage system (**BESS**), involving in this case total storage capability of 50 kWh;
- Contactors to connect to downstream systems from the battery pack;
- Inverter, converting DC to AC power;
- Transformer, converting AC to appropriate voltage level for charger itself; and
- Final DCFC unit itself, which provides delivery of DC power to the electric vehicle being supplied, and with maximum charge rate of 25 kW to the vehicle.

To simplify construction, the overall system employs an available 25 kW charger unit from the manufacturer Delta. While practical, this required AC power delivery at specified voltage to the final charger unit. As such, in this initial configuration, DC power does not flow directly from the charging-system batteries to the vehicle's batteries. Relatively simple modifications are already identified, and desired to be implemented in further upgrade versions, to involve DC-to-DC direct flow of electricity. Not only is the latter more efficient, it obviates the need for and costs of the inverter and transformer components. This anticipated simplification is included in analyses.

An important capital cost component for any battery-based DCFC system is the battery pack itself. In this case batteries were provided free of charge by NFI Group (New Flyer). These batteries were all used extensively in operations of electric buses dating back to approximately 2014, and thus experienced at least four years of consistent operation in actual service. These batteries all involve large-format, prismatic cells manufactured by Xalt Energy, and using lithium-nickel-manganese-cobalt (NMC) chemistry.

While provided at no cost in this case, there are still costs and some residual value that need to be accounted to cover acquisition. Separately, approximate costs for new such batteries were also estimated to allow cost comparisons (described later).

Assumed costs included in the analysis associated with acquisition of used batteries are as follows:

- Fixed labour cost, estimated to be roughly $1,500, required to inspect and test the 50 kWh of batteries making up the pack in order to ensure they are in satisfactory condition; and
- Residual value for the battery pack, which is most likely determined by the value of recoverable minerals, and, which is estimated as a starting point to be about $1,500 for 50 kWh (and as discussed later this represents approximately 10% of the cost for a new battery pack, and is thus reasonable).

The inherent value of lithium-ion batteries is assumed to be based on their recoverable mineral content. This is certainly true for NMC, which appear to be a major battery-chemistry option for BEB, being also used by other manufacturers besides NFI Group. This conclusion was suggested in earlier work on BEB externalities by Parsons et al. (2017), noting the top two mineral components being cobalt followed by lithium, as confirmed by Hall and Lutsey (2018). Although based on somewhat earlier information, Parsons et al. (2017) estimated contents for cobalt and lithium in NMC batteries as:

- Cobalt: approximately 0.36 kg per kWh; and
- Lithium: approximately 0.16 kg per kWh.

Both metal prices are quite variable, but are currently upwards of about $60 per kg for cobalt and upwards of about $50 per kg for lithium. Together these translate to about $30 per kWh in terms of recoverable metals value. This would value a used-NFI battery pack of 200 kWh at about $6,000, and would translate to battery pack cost for the B2U DCFC system, involving 50 kWh, of about $1,500. Such a value will need to be confirmed on an ongoing basis, but provides a starting point reference.

Capital cost data for the B2U DCFC system, as constructed, are summarized in Table 2, along with comparative costs for the suggested improvements to reduce costs, and also based on using new batteries rather than repurposed batteries:

Table 2: Capital Cost Data for Battery DCFC Systems (Building Connected)

Component	**Value**			
Item	**Current B2U**	**Improved B2U ***	**New Batteries**	**Improved New ***
Practical 1-hr Charge	23 kWh	23 kWh	23 kWh	23 kWh
Estimated Lifespan	10 years	10 years	10 years	10 years
Cost of Money	5%	5%	5%	5%
PVIFA Value	7.72	7.72	7.72	7.72
Capital Cost Components				
Grid Connection	Not material in any of these cases **			
Battery Verification	$1,500	$1,500	$0	$0
Residual Battery Value	$1,500	$1,500	$0	$0
Battery Purchase	$0	$0	$15,000	$15,000
Battery Charger	$7,000	$7,000	$7,000	$7,000
Inverter	$10,000	$0	$10,000	$0
Transformer	$2,500	$0	$2,500	$0
Vehicle Charger	$12,500	$12,500	$12,500	$12,500
Total Capital Cost	$35,000	$22,500	$47,000	$34,500
Annual Cost Coverage	$4,560	$2,880	$6,100	$4,400
Monthly Cost Coverage	$380	$240	$510	$370

* Improved version, whether B2U or using new batteries, involving simplification to allow direct DC flow to vehicle batteries, reducing capital cost

** Cost for grid connection in all these cases is considered to be not material given the location of the battery system within an existing building structure, but noting in the case of a stand-alone containerized unit, grid connection costs are considered

Several additional considerations are included. First, is the capital cost of the battery-based DCFC system if new batteries are considered, this to permit a rough comparison. In order to approximate such costs, the same station components are considered as for the B2U DCFC (both to match the system as constructed and if the same suggested simplifications are undertaken), except with costs added to purchase new batteries.

BloombergNEF (2021) suggested battery costs by 2020 had declined to roughly $137 USD per kWh (about $175 CAD per kWh). That said, battery costs associated with practical applications tend to be higher. Recently, GreenCars (2022) showed approximate costs of batteries associated with four prominent electric vehicle models (i.e., Nissan Leaf, GM Volt, GM Bolt and Tesla Model S), translating to a mean of about $230 USD per kWh, or about $300 CAD per kWh. Based on the latter, the cost of a new battery pack of 50 kWh would translate to about $15,000, as employed.

As seen, the B2U capital costs are consistently about 25% to 35% lower than if new batteries are employed. This is a significant reduction. Even if the current B2U system is compared to the version with new batteries but with the cost simplifications implemented, the costs are about the same, emphasizing enhanced viability.

A second consideration is added costs for a stand-alone system, discussed later on in Section 2.3.

2.2 Grid-Based Station Specifications and Capital Costs (Building-Connected)

In terms of comparing direct economic viability of the B2U DCFC system, the conventional baseline is represented by grid-connected DCFC systems as are now commercially available. There is increasing recognition that these latter systems can be expensive, in particular as the power-levels provided increase. As yet less well-recognized, however, is that the effective lifespans of components and high-power systems overall can be limited. This is partly due to the operational stresses imposed on components by high power levels, but also partly due to obsolescence.

This situation is illustrated by respective warranty periods provided to those for electric vehicles, emphasized by the fact that higher-power DCFC systems have costs roughly at the same order of magnitude as individual electric vehicles. Electric vehicle manufacturers typically provide eight-year warranties, while much shorter periods are provided for DCFC systems, typically around one-year up to five-year, but the latter typically involving a higher-cost extended-warranty purchased by the user. Warranties also do not typically cover consumables, such as connection cables. Obsolescence is directly illustrated by the first DCFC system in Winnipeg, which indeed was sited at RRC Polytech (2015). This system, involving a power level of 30 kW, was provided by Eaton Electric, a major electrical systems supplier in North America. However, not long afterward Eaton announced that it was exiting the commercial electric vehicle charging market (Cole 2015), and all their equipment in place were left ultimately as orphans.

In terms of capital costs for conventional DCFC systems, Natural Resources Canada (NRCan 2022), as part of their Zero-Emission Vehicle Infrastructure Program (ZEVIP), effectively provides comparative limit-costs to cover the purchase and implementation of charging stations, i.e., the ZEVIP will typically provide specified incentives levels to cover up to 50% of implemented cost. Incentives are summarized in Table 3, and include Level 2 system incentives for rough comparison.

Table 3: NRCan Incentive Levels to Cover 50% of Installed-Costs of Systems

Charging Level	Power Level	Maximum Incentive
Level 2	3.3 kW to 19.2 kW	\$5,000
DCFC	20 kW to 49 kW	\$15,000
DCFC	50 kW to 99 kW	\$50,000
DCFC	100 kW and above	\$75,000

In order to provide economic comparisons, the following approximate grid-connected DCFC system options are identified for consideration:

- Grid-connected DCFC with power level of 25-kW, directly comparable with the B2U DCFC system, and also very close to 30-kW system as employed already at RRC Polytech;
- Grid-connected DCFC with power level of 60-kW, roughly twice that of B2U DCFC system; and
- Grid-connected DCFC with power level of 120-kW, roughly four times faster than the B2U DCFC system.

Capital cost data for grid-connected DCFC systems, as employed in the basic analyses, are based primarily on limit-costs permitted by NRCan (2022) and are summarized in Table 4.

Table 4: Capital Cost Data for Conventional DCFC Systems (Building Connected)

Component Item	**Value**		
	25-kW DCFC	**60-kW DCFC**	**120-kW DCFC**
Practical 1-hr Charge	kWh	kWh	23 kWh
Estimated Lifespan	10 years *	5 years *	5 years *
Cost of Money	5%	5%	5%
PVIFA Value	7.72	4.33	4.33
Capital Cost Components			
Grid Connection	Not material in any of these cases **		
Total Capital Cost	$30,000	$100,000	$150,000
Annual Cost Coverage	$3,840	$23,040	$34,680
Monthly Cost Coverage	$320	$1,920	$2,890

* Estimated effective lifespans not entirely clear and require ongoing re-evaluation

** Cost for grid connection in all these cases is considered to be not material given the location of the DCFC is in proximity to an existing building structure, but noting in the case of a stand-alone DCFC unit, grid connection costs are considered

It is well-understood that there is still significant variability in the capital costs for DCFC systems. Importantly, the above cost values are reasonably consistent with other sources, including Smith and Castellan (2015), Marcon (2016), Nicholas and Hall (2018) and Nicholas (2019). Unfortunately, realistic lifespan data for systems are not readily available. Lifespan assumptions noted are considered reasonable based on experience to date. As noted, ongoing monitoring and re-evaluation of lifespan values will be needed proceeding into the future.

2.3 Stand-Alone Station Cost Implications

Second, is to consider the cost of a stand-alone containerized B2U DCFC in order to explore and verify the suitability of new sites for a more expensive grid-connected DCFC, as described earlier. For all other cases outlined, grid connection within an existing building is considered, whether for battery-based or for conventional grid-connected, with the cost of the grid connection itself considered to be not material. In the case of a stand-alone DCFC, grid connection costs are considered for both battery-based and conventional, as well as the containerization costs for the B2U DCFC, which are approximated to be about $10,000 in terms of initial capital. Based on assumed PVIFA value as noted, monthly coverage costs translate to $110.

For any stand-alone site, grid-connection sites, where potential electrical service upgrades are required, this will impose further capital costs that are additional to basic equipment installation. Based on analyses described by Smith and Castellan (2015), these costs are assumed as approximately $2,000 for the 11-kW load for B2U, $4,500 for 25-kW level (grid-connected system), $8,000 for 60-kW level, and $12,000 for 120-kW level. Using assumed PVIFA values, as noted, monthly coverage costs translate to $20 for 11 kW input B2U, $50 for 25 kW level, $150 for 60 kW level, and $230 for 120 kW level.

2.4 Operational Costs for Battery-Based and Grid-Based Stations

Unlike electric vehicles themselves, for which economic viability is hardly sensitive at all to the cost of electricity, operational costs are critial when considering the relative viability of DCFC systems for vehicle charging, in particular because of demand fees. DCFC systems impose significant instantaneous demand loads (i.e., electricity use rates in kW rather just energy consumed in kWh). This is particularly acute when power levels for DCFC are increased. For home-based and, to a significant extent workplace-based systems, payments to electrical utilities are based on energy fees per kWh employed. For commercial sites hosting DCFC systems, however, demand fees will be imposed. These can be expensive, and also can vary significantly between individual jurisdictions and utilities, depending on circumstances. The analysis is not straightforward, nor are results derived from any one jurisdiction necessarily applicable directly to another.

In a recent article in Forbes Magazine, Templeton (2020) outlines a recognized problematic trend in consumer expectations for electric vehicle charging, termed “gasoline thinking.” This involves the desire for reasons of convenience to have times for recharging electric vehicles match the rates of refueling for gasoline vehicles, this in energy units per time. This translates to extremely high charge rate expectations of at least around 250 kW. This, however, is expensive, has dramatic grid impacts and involves significant demand fees. Use of lower power level DCFC charging is thus desirable from a cost and overall effectiveness perspective. Following directly along this line, analysts from McKinsey (Knupfer et al. 2018) identify the importance of incorporating battery-based energy storage systems (**BESS**) specifically as a means to adjust demand and reduce associated demand costs. This reduction of demand fees thus translates to a significant competitive advantage for B2U DCFC when compared to conventional grid-connected systems.

The obvious priority jurisdiction to consider for operating cost evaluation is Manitoba. At the same time, a number of other provinces still employ single-utility provider operations involving relatively straightforward tariffs, not extensively incorporating more-complex time-of-use rates, nor variable open-market energy pricing. Additional provinces with simpler rate structures include: Quebec, British Columbia (B.C.), Saskatchewan, Nova Scotia and New Brunswick. Approximate current energy and demand fees for all six jurisdictions are outlined in Table 5. Rates presented are based on current tariff structures for suitable sites and rate categories, primarily general service or commercial, and show the breadth of situations that can be encountered. Quebec is particularly complex and interesting, involving a change in both demand and energy fees once demand reaches 50 kVA. Provinces, like Ontario and Alberta, incorporating open energy markets and/or extensive time-of-use pricing are more complex and require more in-depth assessment.

Table 5. Approximate Energy and Demand Fees for Relevant Commercial Sites

Item	**Energy Fee ***	**Free Demand**	**Demand Fee**
Units	$ per kWh	Free to kVA	$ per kVA/mon
Primary Jurisdiction			
Manitoba	$0.045	n/a	$11.50
Other Jurisdictions			
Quebec (< 50 kVA)	$0.100	50	n/a
Quebec (≥ 50 kVA)	$0.051	n/a	$14.80
B.C.	$0.096	n/a	$5.40
Saskatchewan	$0.083	50	$15.60
Nova Scotia	$0.097	n/a	$10.50
New Brunswick	$0.099	20	$11.20

* Energy fee based on incremental "balance" of use, and includes carbon taxes

Sources: Manitoba Hydro (2022), Hydro Quebec (2022a) Hydro Quebec (2022b), BC Hydro (2022), Sask Power (2022), Nova Scotia Power (2022) and NB Power (2022)

2.5 Operational Characteristics for Battery-Based and Grid-Based Stations

For determining and comparing the operational costs of DCFC, systems their respective operational characteristics become important. This relates both in terms of estimating maximum power demand levels and costs, and determining total daily charging capability, which relates to the extent of coverage possible.

The former is more straightforward to evaluate, with demand levels from the electricity grid for respective DCFC systems summarized in Table 6. At the relatively preliminary level of evaluation undertaken, power factors and power factor correction are not considered, but would need to be included for more detail assessments.

Table 6. Electrical Grid Demand Levels for Respective DCFC Systems

DCFC System Type	**Electrical Grid Demand (kVA)**
Battery-Based DCFC (All Versions)	11.0 kVA
Grid-Connected DCFC 25 kW	25.0 kVA
Grid-Connected DCFC 60 kW	60.0 kVA
Grid-Connected DCFC 120 kW	120.0 kVA

One practical expectation for all DCFC stations, irrespective of type or power level, is that they would be primarily operated over day-time hours. This can be represented by the 12 hours over any given day from 8:00 AM to 8:00 PM. Little charging, if at all, would be anticipated outside this timeframe.

Maximum allowable charging by the B2U DCFC system involves delivery of 23 kWh over up-to-a maximum of one-hour allowed per vehicle. Earlier this was noted as representing in the range of 110 to 130 km additional distance for a typical electric vehicle, and is both adequate and suitable for an urban-based station primarily providing top-ups under more urgent conditions. This amount of charging is thus deemed as the desired **model-charge event** needed for vehicles.

Given design, the B2U DCFC would begin a typical day with full battery charge of 50 kWh available. This means the system is capable of delivering up to two model-charges of 23 kWh in sequence immediately, but would then require additional recharging from the grid to permit further such charging events. During a 12-hour daytime period, the B2U DCFC could be recharged as much as 132 kWh, given 11 kW rate, translating thus to maximum possible energy available of about 182 kWh. This would permit as many as seven such model-charge events (note value is over seven but not fully eight).

A conventional grid-connected 25 kW DCFC, on the other hand, would be able to accomplish fully 12 model-charge events over a day. This means the B2U DCFC system can only provide roughly 58% of the total model-charge events over a day, but at the same time requiring only 44% of demand. In terms of further, higher-power DCFC systems:

- Grid-based 60 kW DCFC can provide 23 kWh in approximately 25 minutes, and provide up to 31 model-charge events in a day. In this case the B2U DCFC can provide about 23% of maximum daily charging capability but requiring only 18% of demand.
- Grid-based 120 kW DCFC can provide 23 kWh in approximately 12 minutes, and provide up to 62 model-charge events in a day. In this case the B2U DCFC can provide about 11% of maximum daily charging capabilities but requiring only 9% of demand.

The obvious follow-up question for evaluating viability is the extent to which DCFC stations are actually employed in practice currently? Hardinghaus et al. (2020) recently evaluated information for existing DCFC in Europe, and found average charging events involved delivery of about 23 kWh for CHAdeMO protocol stations and about 17 kWh for CCS Combo (SAE) protocol stations, both values very similar to the model-charging event described earlier for the B2U DCFC. Further, they found the average number of charge-events for both types of stations were less than 19 times per month (assumed as 30 days), or about 0.6 events per day. Compared to a 25-kW conventional grid-connected DCFC, this represents daily utilization of not more than 5% in practice. Lee and Clark (2018) noted that utilization levels for commercial stations have been optimistically considered around 10%, but even at such levels are not economically profitable. Based on this, “optimistic expectations” of daily utilization translate to just over once per day for a 25 kW DCFC system, even less for higher power DCFC.

While B2U DCFC stations cannot match theoretical charging capabilities for grid-connected systems, their capabilities are well above actual practical utilization. This illustrates where advantages exist. The B2U DCFC offers important competitive advantages while operational utilization levels for DCFC remain relatively low.

3.0 Bases for Sustainability-Related Externality Benefits

3.1 General Sustainability Implications of Electric Vehicles

In considering sustainability implications of the B2U DCFC system, it is useful to first consider electric vehicles more broadly. Such vehicles are classified as zero-emission vehicles (**ZEV**), and include a variety of both light-duty passenger cars and heavy-duty transit buses (**BEB**). Importantly, electric vehicles are generally considered to be positive overall from a sustainability perspective, in particular compared to fossil fuel vehicles.

Electric vehicles of all types incorporate on-board battery-based storage of electricity obtained from local electric-grids, that is then used to power motive operations. All of these vehicles thus involve significant reductions in the use of and the reliance on conventional fossil fuels, whether gasoline or diesel respectively. While dubbed ZEV, it is also well-acknowledged that they still do produce adverse implications, both environmental and social in nature, with relevant complexities outlined for example by Choudhury (2021) regarding the U.S., and Common and English (2019) regarding Canada. Further, the nature of identified negative implications of electric vehicles, primarily, relate to the GHG-intensity of local electricity grids used to power them, and secondarily, relate to their batteries and various implications associated with manufacturing. The latter provides the direct connection to estimate externality benefits.

The B2U DCFC in this case specifically employs used-batteries from transit buses (BEB). Parsons et al. (2017) undertook a relatively comprehensive review of different sustainability implications specifically for the same type of BEB from which these batteries are sourced, albeit on an earlier and more preliminary basis. Positive and negative factors are identified, as summarized in Table 7.

Table 7. Major Positive and Negative Externalities (Parsons et al. 2017)

Identified Positive Externality Factors	Identified Negative Externality Factors
• Reduced greenhouse gas (GHG) emissions • Reduced fuel-price volatility • Reduced noise effects • Reduced smog-pollutant emissions • Reduced lubricants and fluids disposal • Reduced acid-precipitation emissions	• Rare-mineral scarcity concerns (somewhat uncertain at time of the earlier paper) • Infrastructure damage due to higher vehicle masses involved • Used-battery disposal (highly uncertain at time of the earlier paper)

Of all of the factors considered above, the largest identifiable factor from a monetary perspective involves GHG emissions. Given that a major component of the full lifecycle emissions of a typical electric vehicle are associated with battery manufacture, this is highly relevant to consider for the B2U DCFC system. At the same time, the most uncertain of the factors considered above involve used-battery disposal and rare-minerals scarcity.

As outlined by Ambrose and O'Dea (2021) on behalf of the Union of Concerned Scientists, the availability, recyclability and sustainability of battery materials remain concerns, indeed of growing significance. They note since 2010 more than 60,000,000 kWh of lithium-ion battery capacity of all types has been deployed in the U.S. alone within electric vehicles, with roughly a quarter of that value or about 16,000,000 kWh, deployed since 2019. Given the advent of commercial electric vehicles began in 2010, still only a very small number of vehicles have been reaching effective end-of-life for their batteries. Battery recycling and disposal needs and associated business activities thus remain still nascent, but are well understood to escalate dramatically into the future.

Based on the above, evaluation of the externality benefits associated with the B2U DCFC system considers; **firstly**, avoided costs associated with GHG emission implications of battery manufacturing; **secondly**, avoided costs associated with rare minerals scarcity, and with battery recycling and disposal operations; **thirdly**, avoided costs of problematic social considerations associated with minerals extraction; and **lastly**, additional costs potentially avoided as associated with environmental and social factors not previously considered.

3.2 GHG Emissions Implications of Battery Manufacturing

A significant environmental benefit involved with repurposing of batteries for the B2U DCFC can be considered as obviating the need for new batteries in the same application. The concept of battery-based DCFC offers economic advantages, applicable whether the batteries involved are new or repurposed. Lower associated costs for repurposed batteries represent an economic advantage for the B2U DCFC, as discussed earlier, while from an environmental perspective part of the advantage can be quantified in terms of avoided emissions, and other associated externality costs, in not having to manufacture a new battery in the first place.

GHG emissions associated with electric vehicle battery manufacturing are already discussed in extensive literature. There are a host of studies available, but also a variety of strongly conflicting opinions regarding the extent of emissions, sometimes controversial. There is obviously, thus, no consensus perspective on this subject.

Within the literature in general, GHG emissions associated with the initial manufacturing of electric vehicles, in particular their batteries tend to be viewed as being greater than those associated with conventional internal combustion engine vehicles (**ICEV**), recently reiterated by Xia and Li (2022). Lifecycle emissions of ICEV on the other hand are overwhelmingly dominated by fuel consumption. This situation has led many researchers to define distance "deficits" or minimum "breakeven" travel distances for electric vehicles, in order for their overall cumulative emissions to begin to drop below those for comparable conventional ICEV.

Hall and Lutsey (2018) for ICCT summarize the results of eleven lifecycle emissions studies on electric vehicle batteries from 2011 through 2017. Estimated lifecycle emissions vary dramatically from as low as 30 kg GHG per kWh to as high as 490 kg GHG per kWh. These values suggest a very broad range of potential emissions associated with a 50-kWh battery pack, as used in this case, ranging from as little as 1.5 tonnes to as much as 24 tonnes. A more likely value is somewhere within this range. A number of factors are also identified as influencing the extent of GHG emissions:

- Type of lithium-ion battery chemistry involved;
- Location of manufacturing, especially relating to local GHG grid-intensity;
- Size of battery pack involved (also relating to size of vehicle involved); and
- Timeframe for manufacturing, given on-going process improvements continue to reduce emissions associated with battery manufacture.

Unfortunately, the major manufacturing locations for electric vehicle batteries have all tended to be countries with electrical grids having relatively higher GHG-intensities, notably China, South Korea, Japan and the U.S. As noted earlier, the batteries incorporated in the NFI transit buses and used for the B2U DCFC, all ultimately come from Xalt Energy, are made in the U.S., and involve NMC-type chemistry, but with chemistry-specifics not certain. Also, even though repurposed batteries themselves would have been manufactured in the past and would have likely involved more significant emissions during manufacture, the action of repurposing displaces current battery production needs, such that the most up-to-date battery manufacturing emissions are most relevant to consider in this case.

A recent White Paper for ICCT by Bieker (2021) outlines expected specific manufacturing emissions per kWh by battery chemistry, and by country of manufacture. Three different types of NMC chemistry batteries are outlined (Refer to Table 2.3 in that paper), but with no further explanation of details associated with calculations. An approximate value for such batteries manufactured in the U.S. in 2021 is indicated as about 60 kg GHG per kWh. A further, small upward adjustment is made to this value, recognizing that Xalt Energy's facilities are located in the State of Michigan, with a grid intensity of approximately 506 g GHG per kWh, versus overall average for the U.S. of 432 g GHG per kWh (Carbon Footprint 2020). This translates to a slightly more conservative emissions value for the battery pack of about 70 kg GHG per kWh, based on somewhat higher grid-intensity, and further translates to emissions associated with a new 50-kWh battery pack of approximately 3.5 tonnes GHG.

This value can be roughly compared in terms of an equivalent "breakeven" travel distance estimate. Assuming a modest gasoline vehicle with fuel consumption of 10 Litres per 100 km, pure gasoline combustion emissions factor of about 2.32 kg GHG per Litre, and 10% renewable fuel content translates to emissions generation of about 21 kg

GHG per 100 km. This would set the "breakeven" travel point close to about 17,000 km (i.e., 3,500 kg GHG ÷ 21 kg GHG per 100 km). This value is reasonably close to typical annual travel for an ICEV in Manitoba. A roughly one-year period is often suggested as reasonable for breakeven equivalency, suggesting the value itself appears reasonable.

An important, and standardized, means to monetize GHG emissions is using the social-cost of carbon (**SCC**). The SCC is estimated as reflecting the present-value of future damages resulting from the release today of a unit of GHG (typically per tonne basis). Currently, based on analyses (ECCC 2016), the Government of Canada assumes a social-cost of carbon of approximately $50 per tonne GHG in evaluating costs and benefits. Importantly, the SCC is very different from carbon pricing, even though the two values currently coincide at $50 per tonne GHG. The latter value involves a price "signal" levy that is applied to fossil fuels in an attempt to reduce consumption, rather than reflecting future damages.

Using a $50 per tonne SCC, the present value benefit of avoiding GHG emissions for battery repurposing in this case translates to about $175 (i.e., 3.5 tonnes GHG × $50 per tonne). In terms of sensitivity, a higher-emissions level of 24 tonnes, as noted earlier, translates to avoided GHG emissions costs of about $1,200 (i.e., 24 tonnes GHG × $50 per tonne), representing essentially a higher-end limit value.

Using a 10-year lifespan and 5% cost of money (with PVIFA = 7.22), as outlined in Section 2.1, the estimated GHG benefit of $175 translates to a monthly value of approximately $2.00. As seen, this externality benefit is relatively small.

3.3 Rare Minerals, Battery Recycling and Disposal Implications

Electric vehicles are frequently viewed as critical technologies for achieving future transportation sustainability, providing opportunities to: dramatically reduce consumption of fossil fuels, and associated significant GHG emissions; transition to clean energy sources; enhance energy efficiency; and reduce other environmental problems, such as urban smog-related pollution. Yet, at the same time, there are significant concerns in meeting future transportation and energy demands, in particular supply risks of key, relatively scarce mineral resources, environmental impacts of their extraction, and associated social and ethical concerns (Parajuly et al. 2020, Church and Wuennenberg 2019). Issues around relative scarcity and value of key minerals are intrinsically linked to recycling and disposal.

Disposal of electric vehicle batteries can be problematic, in particular given the anticipated dramatic increase in such batteries reaching end-of-life. Simply discarding to landfills would be highly wasteful, and improper disposal also could lead to potential for groundwater pollution (Taylor 2009). Further, lithium-ion batteries for electric vehicles on their own have been technically considered as dangerous goods for transportation within Canada and elsewhere (Transport Canada 2016), albeit with restrictions so far only applied to air-transport. Lithium-ion batteries are grouped under Class 9, i.e., miscellaneous hazardous materials. While not inherently hazardous, such batteries can become a concern under certain specific circumstances (Huo et al. 2017). It is also thus possible that used lithium-ion batteries could at some point in the future be classified as hazardous wastes, which would dramatically increase associated disposal costs.

Lithium-ion batteries also tend to be more difficult to recycle or reuse. Parsons et al. (2017) noted this is because, unlike relative simply lead-acid batteries, they involve more-complex construction, more variable and diverse composition, and are more "composite" in nature. Two major approaches for recycling are noted:

- **Hydrometallurgical** processes, which use water and chemicals to recover constituents and metals; and
- **Pyrometallurgical** processes, which break down batteries through thermal treatment.

Parsons et al. (2017) also identified that into the future there are likely three main options for dealing with lithium-ion battery end-of-life as outlined by Gaines (2014):

- **Smelting** involves high-temperature processing that consumes organic constituents and reduces the battery components down to residual metals, including cobalt, copper, nickel, iron and others. This is the simplest and easiest approach for recycling, being entirely pyrometallurgical in nature, but does not allow the batteries to remain directly part of the supply chain. It is also energy intensive and requires the flexibility of accepting a diverse array of battery chemistries. The positive side is that smelting does recover potentially scarce metals, in particular cobalt, that can be valuable for resale and can be readily reused again to manufacture of new batteries.
- **Intermediate recycling** involves the separating of plastics and metals, typically via hydrometallurgical methods, and then uses liquid filtration to separate metals such as aluminum to reclaim and recycle. It is more time consuming and costly, and is likely only economical if a recycler can guarantee to reclaim the more valuable cobalt and nickel components from the battery. Such processes show promising results, but have yet to be employed at large scale.
- **Direct recycling** recovers most of the battery materials for reinsertion into the battery supply chain. All the materials are recovered, including the valuable cathode constituents. Such processes, however tend to be still more "developmental" in nature, including recently announced activities at Saskatchewan Research Council (Thalgott 2022).

The importance of a "circular economy" approach for electric vehicle batteries is already well recognized (Richter 2022, Dunn et al. 2021). At the same time, so too is the strong realization that recycling alone cannot entirely prevent future key mineral shortages, particularly regarding cobalt (Zeng et al. 2022). A recent article in the trade publication Mining (2022) suggests recycling will not represent a "silver bullet" to alleviate demand pressures, likely supplying by 2030 less than 8% of global cobalt demand, and less than 6% of global lithium demand. Recognizing this situation emphasizes the importance of repurposing batteries to the extent possible in order to alleviate future market pressures for new batteries, and to effectively reuse rather than recover minerals and components.

Cobalt processing, whether for new mineral extraction or recycling, tends to be much more complex in nature, with a variety of subtleties in terms of relative advantages and disadvantages. Summary cobalt process details are available (e.g., Bruckner et al. 2020). As outlined by Farjana et al. (2019) and Dia et al. (2018), new cobalt mineral extraction operations tend to involve hydrometallurgical processes. On the other hand, pyrometallurgical processes are significant for recycling, as outlined by Assefi et al. (2020), this primarily because of inherent simplicity. Zhou et al. (2021) further note that productivity of such processes also can be high, with high recovery efficiency for specific constituents, specifically cobalt. At the same time a compromise is present, in that lithium recovery can end up being significantly sacrificed in deference to recovery of cobalt. This leads to identifying two major adverse impacts that are relevant to recycling of batteries, and can be monetized. First involves avoiding GHG emissions associated with high-temperature smelting as part of recycling processes, for which the energy source tends to be coke, and second is avoiding the loss of the value of lithium mineral content.

Zhou et al. further estimate that emissions associated with pyrometallurgical processing are around 2,200 kg GHG per tonne of end-of-life batteries processed. An earlier report by CARB (2015) suggested the specific energy of NMC battery packs is typically around 0.15 kWh per kg, such that a 50-kWh battery pack has a mass of about 340 kg. As such, emissions translate to about 750 kg GHG (i.e., 2,200 kg GHG per tonne batteries × 340 kg ÷ 1000 kg per tonne), and further that associated emissions costs, based on the SCC, translate to about $37.50 (i.e., 750 kg GHG × $50 per tonne GHG). When compared to the avoided costs of emissions for battery manufacture, this value translates to about 20%, which is reasonable compared to the overall product manufacture.

In terms of lost lithium and lithium value associated with pyrometallurgical processing of used batteries, as noted earlier (see Section 2.1), the lithium content of the 50-kWh battery pack is estimated to be about 0.16 kg per kWh, translating to about 8 kg (i.e., 0.16 kg per kWh × 50 kWh). Given a current value of about $50 per kg for lithium, as also noted, this further translates to a cost of lost lithium of about $400 (i.e., 8 kg × $50 per kg), which is larger than the cost of GHG emissions from smelting.

Again, using a 10-year lifespan and 5% cost of money (with PVIFA = 7.22), as outlined in Section 2.1, the estimated benefits of avoiding GHG and lithium losses in smelting recovery of cobalt total on a present value basis to $437.50, and translate to a monthly value of approximately $5.00. As seen, this externality benefit is also relatively small, and also suggests the largest savings is associated with not losing lithium, rather than avoiding GHG.

3.4 Problematic Social Considerations Associated with Minerals Extraction

The recognition of problematic social-related problems for minerals extraction has become a prominent recent consideration for electric vehicles, in particular relating to cobalt. As adroitly summarized by the World Economic Forum (WEF 2020):

> Global demand for cobalt, a key component of lithium-ion batteries used in consumer electronics and electric vehicles, is expected to grow four-fold by 2030. More than 70% of the global production of cobalt takes place in the Democratic Republic of the Congo (DRC), of which 15% to 30% comes from so-called artisanal and small-scale mines (ASM), where independent miners use their own resources to extract the mineral. Sourcing cobalt from the DRC is linked to major human rights risks, which have been widely documented. The prevalence of ASM in the cobalt supply chain also creates challenges for establishing responsible sourcing practices.

The situation regarding cobalt, especially in the DRC has become a high-profile case study, with extensive qualitative discussions in the literature (for example with review summary by Sovacool 2019). Specific problems already identified include:

- Unsafe working conditions;
- Safety concerns exacerbated by the effective off-loading of responsibilities to miners;
- Relatively poor pay;
- Extensive use of relatively young workers (outlined by Lawson 2021);
- Excessive violence situations including deaths;
- Excessive blood-levels of metals in workers and proximal communities (specifically identified by Nkulu et al. 2018); and
- Additional water and air pollution concerns impacting proximal communities.

Yet, even in this case there is still little quantitative data available, so it has proven difficult to attach costs to the growing problems. That said, the above well recognized situation has been leading in two positive directions for improvement:

- Recommendations to improve social-life cycle analysis (S-LCA) methodologies in order to better quantify concerns, and from this be able to attach monetary values, but still not yet fully formalized (Bamana et al. 2021, Zackrisson 2021); and
- Initiatives by vehicle manufacturers to adjust lithium-battery chemistries employed in vehicles in particular to reduce cobalt reliance (Castelvecchi 2021).

Given the situation as described, it is recognized that significant adverse social-related problems certainly result from extraction of battery minerals, and further that these can involve significant implicit costs. Within this analysis, however, no specific cost values are included due to a lack of adequate information.

3.5 Additional Environmental and Social Factors not Previously Considered

A variety of additional adverse environmental and social implications have begun to emerge, and will likely continue to emerge at electric vehicle and battery technologies mature. Additional potential problem areas include:

- Water pollution associated with minerals and battery production, in particular from hydrometallurgical processing of minerals, especially cobalt. These are already

recognized, as noted earlier and in additional literature (Farjana et al. 2019, Zackrisson 2021), but not monetized due to a lack of adequate information.
- Pollution concerns associated with inadequate disposal of used-batteries as wastes, not yet seen given very small numbers, but potentially mounting as the number of electric vehicles increases. Batteries and components simply dumped improperly into the environment can certainly lead to adverse impacts, and will depend on disposal compliance.
- Additional air pollution concerns associated with battery recovery processes, in particular smelting, again still relatively small but potentially growing.
- General concerns regarding advancing the sustainability of mining and extraction given increasing reliance on critical minerals as the world economy attempts to transition away from fossil fuels (Malan 2021). The nature of future emerging problems is uncertain, i.e., "unknowns" that are unknown.

One last future consideration identified, but not directly included in this analysis is the proportion of batteries that may end up after primary-use being unacceptable for repurposing. Based on experience so far, this is estimated to be very small, only around 5% or so, however, better quantifying actual statistics will become increasingly important as the numbers of used-batteries continues to mount.

4.0 Results of Economic and Externality Analyses

4.1 Basic Economic Comparisons for Building-Connected Stations

The basic economics for the B2U DCFC are compared on **monthly-cost** bases in Table 8 and Table 9 for building-connected systems. Results include a combination of costs necessary to cover both capital and operating expenses for a future month, based on siting in Manitoba, and presenting two operational-utilization levels. While in the tables, comparative costs are presented on monthly-bases for future years, rather than present value costs, the comparable results are still valid, and are likely most relevant for comparing DCFC systems. Present values can be easily calculated by multiplying future-year monthly costs firstly by 12 to obtain future year annual costs and secondly by the applicable PVIFA values, as have been estimated for all cases.

Seven DCFC options are considered, as follows:

- **Current B2U** DCFC system, based on the unit as constructed, connected to a building, and proven through demonstration to be fully operational and functional;
- **Improved B2U** DCFC system, based on already identified simplifications and improvements to maintain operational capability but reduce capital costs;
- **New Battery** DCFC system, identical to the current B2U, except employing new batteries rather than repurposed batteries;
- **Improved New** battery DCFC system, identical to the improved B2U, except employing new batteries rather than repurposed batteries;
- **25-kW** DCFC grid-based system, connected to a building;

- **60-kW** DCFC grid-based system, connected to a building; and
- **120-kW** DCFC grid-based system, connected to a building.

Operational utilization assumptions are based, as outlined previously, on a model-charge event of 23 kWh, daily operational period of 12 hours per day, and monthly period of 30 days. For battery-based or 25-kW grid-based stations, a total of 360 model-charge events are possible over one month (i.e., 12 one-hour periods per day delivering at least 23 kWh × 30 days per month). The two operational levels assumed involve:

- Results in **Table 8** are for station **utilization** of **5%**, or approximately 0.6 model charge-events per day throughout a given month (i.e., 360 events per month × 0.05 ÷ 30 days), reflecting data on current actual utilization of DCFC stations, as outlined earlier; and
- Results in **Table 9** are for station **utilization** of **10%**, or approximately 1.2 model charge-events per day throughout a given month (i.e., 360 events per month × 0.10 ÷ 30 days), reflecting optimistic utilization of such systems, as also outlined earlier.

For 60-kW or 120-kW grid-based systems, the same numbers of model charge-events and energy delivery are assumed the same as above. For these cases, actual utilization values will be obviously lower given the greater capacity of the respective systems, i.e., approximately 2.1% and 4.2%, respectively, in the case of a 60-kW system, and approximately 1.0% and 2.1%, respectively, in the case of a 120-kW system. That said, however, for consistency, these situations are still presented under the same labels representing "5%" and "10%" utilization cases, given they involve the same levels of use and energy delivery.

Table 8. Monthly-Costs for Building-Connected DCFC Systems at 5% Utilization

DCFC Option	Energy Fee	Demand Fee	Capital Cost	Total Cost
Current B2U	$19	$127	$378	$524
Improved B2U	$19	$127	$243	$389
New Battery	$19	$127	$508	$654
Improved New	$19	$127	$372	$518
25-kW DCFC	$19	$288	$324	$631
60-kW DCFC	$19	$690	$1,925	$2,634
120-kW DCFC	$19	$1,380	$2,887	$4,286

Table 9. Monthly-Costs for Building-Connected DCFC Systems at 10% Utilization				
DCFC Option	**Energy Fee**	**Demand Fee**	**Capital Cost**	**Total Cost**
Current B2U	$37	$127	$378	$542
Improved B2U	$37	$127	$243	$407
New Battery	$37	$127	$508	$672
Improved New	$37	$127	$372	$536
25-kW DCFC	$37	$288	$324	$649
60-kW DCFC	$37	$690	$1,925	$2,652
120-kW DCFC	$37	$1,380	$2,887	$4,304

Several observations are apparent from the results in Table 8 and Table 9:

- Monthly-costs are dominated primarily by capital coverage, i.e., in the range of about 50% to 70% of total, secondarily by demand fees, i.e., in the range of about 20% to 40% of total, and with energy fees being relatively unimportant;
- Relatively low importance of energy fees further translates to station utilization also becoming relatively unimportant, within practical limits, given that increased utilization solely increases energy fees, which, as noted, are less important;
- Battery-based systems translate to generally lower monthly-costs (or roughly comparable at worst), even though the 25-kW grid-connected system shows a lower capital cost in most cases than for the battery options presented;
- Higher power-level grid-connected systems are even more costly, with the 60-kW system being 5× to 7× more expensive per month, and 120-kW system being 8× to 11× more expensive per month than battery-based systems, this even though only providing respectively about 2× to 4× faster energy delivery;
- Enormous price-premium is required for convenience, using higher power-levels, which is questionable in terms of necessity outside a narrow set of circumstances.

It is obvious that potential advantage for the B2U DCFC system comes significantly from the ability to reduce demand fees via batteries for energy storage, this as more-broadly identified earlier by Knupfer et al. (2018) with McKinsey. There is also some further potential to achieve reduced capital costs, which if successful could further roughly double monthly savings compared to a grid-based 25-kW system.

The maximum number of model charge-events possible for the B2U DCFC system is earlier identified as 7 per day, which translates to as many as 210 over a month (i.e., 7 events per day × 30 days per month). In order to more fully understand the impacts of utilization, monthly-costs are compared in Figure 3 for the **Current B2U** system to the **25-kW** grid-connected system, with utilization varying discretely from 0 to 210 model charge-events per month.

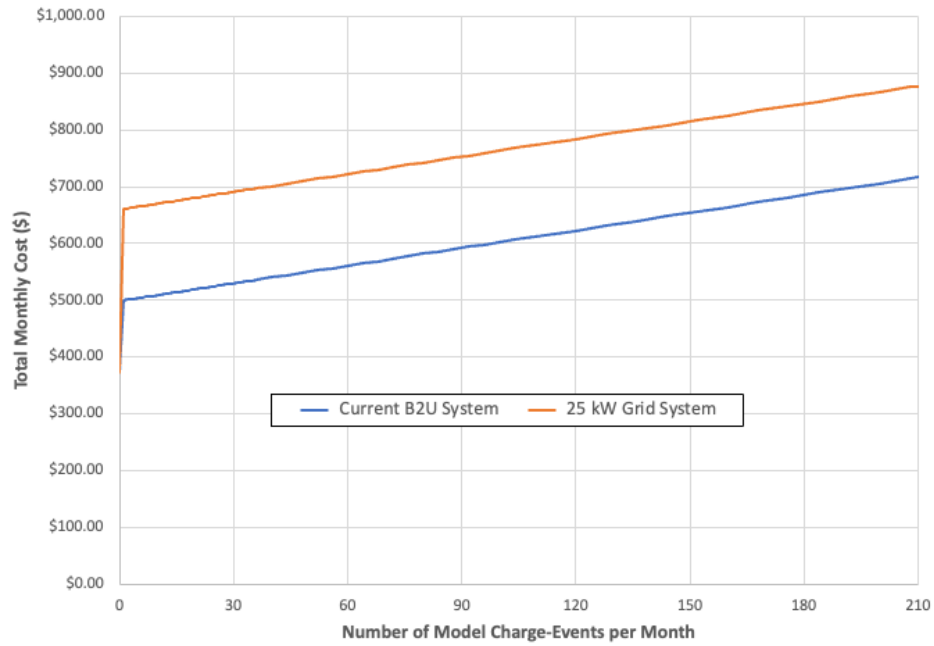

Figure 3. Monthly-costs for current B2U system versus 25-kW grid-based system as a function of model charge-events per month

As is evident from this plot of data, as soon as there is even just one charge-event per month, the current B2U system is less expensive, and this situation is maintained to the maximum monthly capability of the current B2U system. Compared to the grid-based system of 25-kW, this translates to utilization of approximately 60% (i.e., 210 events per month ÷ 360 events per month). Given that even highly optimistic utilization is only around 10%, this means for all practical intent, the current B2U will remain consistently more economical for long into the future. This advantage is also not practically dependent on the degree of utilization.

4.2 Basic Economic Comparisons for Stand-Alone Stations

The basic economics for the B2U DCFC are compared on a monthly-cost basis in Table 10 and Table 11 for stand-alone systems, as for example might be required for a high-way stop. Results again include a combination of costs necessary to cover both capital and operating expenses for a month, based on siting in Manitoba, and presenting two operational-utilization levels. Only four DCFC options are considered, as follows:

- **Improved B2U Containerized** DCFC system, based on already identified simplifications and improvements to maintain operational capability but reduce capital costs, further modified by containerization to ensure all-weather operation and separately connected to the grid;
- **25-kW** DCFC grid-based system, separately connected to the grid;
- **60-kW** DCFC grid-based system, separately connected to the grid; and
- **120-kW** DCFC grid-based system, separately connected to the grid.

Again, two operational utilization levels are considered: 5% utilization, based on current DCFC utilization data; and 10% utilization, which is an optimistic level.

Table 10. Monthly-Costs for Standalone DCFC Systems at 5% Utilization				
DCFC Option	**Energy Fee**	**Demand Fee**	**Capital Cost**	**Total Cost**
Improved B2U Containerized	$19	$127	$372	$518
25-kW DCFC	$19	$288	$372	$679
60-kW DCFC	$19	$690	$2,079	$2,788
120-kW DCFC	$19	$1,380	$3,118	$4,517

Table 11. Monthly-Costs for Standalone DCFC Systems at 10% Utilization				
DCFC Option	**Energy Fee**	**Demand Fee**	**Capital Cost**	**Total Cost**
Improved B2U Containerized	$37	$127	$372	$536
25-kW DCFC	$37	$288	$372	$697
60-kW DCFC	$37	$690	$2,079	$2,806
120-kW DCFC	$37	$1,380	$3,118	$4,535

Several observations are apparent from the results in Table 10 and Table 11:

- Monthly-costs are again dominated primarily by capital coverage, secondarily by demand fees, and with energy fees being relatively unimportant;
- Station utilization, within practical limits, is also relatively unimportant, given its impacts are linked to energy fees;
- Results in this case reflect reasonable expectation rather than performance of an operating system, suggesting that demonstration of a containerized, standalone B2U DCFC system represents an important potential next step.

Again, the advantage for the B2U DCFC in this case derives primarily from its ability, as a battery-based system, to reduce and avoid demand fees.

4.3 Economic Comparisons for Stations across Jurisdictions

As outlined in the past few sections, it is very evident that the economic viability of the B2U DCFC depends to a significant extent on demand fees as imposed by the electrical utility. Earlier, in Section 2.4, the nature of demand fees (i.e., per kVA) and energy fees (i.e., per kWh) across six different provincial jurisdictions were investigated. These six provinces fall into three rough categories in terms of applicable demand fees, as follows:

- Jurisdictions with utilities having consistent and relatively higher demand fees, as applicable within Manitoba and Nova Scotia:

- Jurisdictions with utilities having consistent and relatively lower demand fees, as applicable within BC; and
- Jurisdictions with utilities having variable demand fees, typically involving a threshold level above which demand fees are levied, as applicable within Quebec, Saskatchewan and New Brunswick.

The economics for the B2U DCFC are compared on a monthly-cost basis in Table 12 across all six jurisdictions, as grouped in to their respective three categories above, reflecting total costs to cover capital, demand fees and energy fees. In all cases, costs reflect building-connected systems and involve an operational-utilization level of 5%. Only four DCFC options are considered in this case, with only total monthly-costs presented:

- **Current B2U** DCFC system, based on the unit as constructed, connected to a building, and proven through demonstration to be fully operational and functional;
- **25-kW** DCFC grid-based system, connected to a building;
- **60-kW** DCFC grid-based system, connected to a building; and
- **120-kW** DCFC grid-based system, connected to a building.

(Note: As can be seen, the costs as presented for Manitoba in Table 12, are identical to those presented earlier in Table 8 for the respective systems).

Table 12. Monthly-Costs for DCFC Systems with 5% Utilization by Jurisdiction

Jurisdiction	Current B2U	25-kW Grid	60-kW Grid	120-kW Grid
Higher Demand Fee Utilities				
Manitoba	$524	$631	$2,634	$4,286
Nova Scotia	$533	$626	$2,595	$4,187
Lower Demand Fee Utilities				
BC	$478	$503	$2,300	$3,598
Variable Demand Fee Utilities				
Quebec	$419	$365	$2,834	$3,722
Saskatchewan	$412	$358	$2,115	$4,014
New Brunswick	$419	$421	$2,414	$4,048

The results outlined in Table 12 show a great deal of variability in the economic viability of the B2U system. These results emphasize the need to understand and to evaluate the specific demand fee situation encountered within each different jurisdiction.

Manitoba has been well established as a "low-cost-electricity" jurisdiction, however, Manitoba Hydro at the same time actually does apply relatively-high and consistent demand fees. Manitoba shows the best business case comparing the B2U DCFC to its most direct alternative, i.e., the 25-kW grid-based system, with the savings in monthly-costs amounting to about 17%. Considering this same comparison for the three demand-fee categories shows the following trends:

- Jurisdictions having consistent and relatively higher demand fees show the highest savings for the B2U system, with 17% for Manitoba and 15% for Nova Scotia;
- Jurisdictions having consistent and relatively lower demand fees show savings but much lower, with only 5% for BC; and
- Jurisdictions having variable demand fees show the least beneficial application of the B2U system, with New Brunswick showing essentially no savings, and indeed higher monthly costs for the B2U of roughly 15% shown in both Quebec and Saskatchewan.

Other jurisdictions, most notably Ontario and Alberta, can show generally more complicated utility fee structures, for various reasons as discussed earlier. More detailed economic evaluations would be necessary in these jurisdictions in order to confirm whether or not, and to what extent, the B2U DCFC could provide economic savings.

The above data shows that a strong-correlations appears to exist between the effective monthly demand fee in a given jurisdiction with the resulting monthly-cost difference for the B2U DCFC system in relation to the most-comparable grid-based system, i.e., 25-kW, as illustrated in Figure 4. The results show a coefficient of determination (r^2) value of 0.93. The results of the data plot also allow estimating an approximate "break-even demand fee" required for the existing B2U DCFC system to match the 25-kW grid-based system. This break-even value corresponds to approximately \$4.50 per kVA per month.

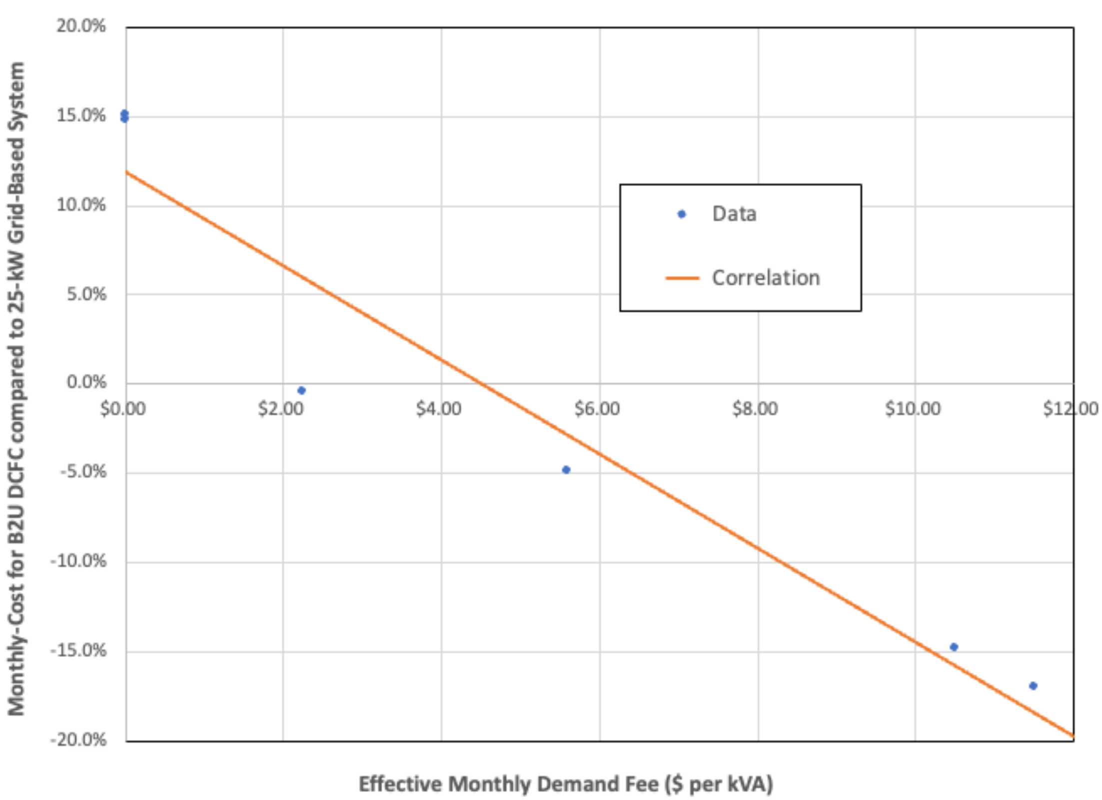

Figure 4. Monthly-costs for current B2U system versus 25-kW grid-based system as a function of effective monthly demand fee per kVA by jurisdiction

4.4 Externality Benefit Comparisons for Stations

As described earlier, it is possible to quantitatively estimate two major externality benefits for the B2U DCFC system, involving:

- Benefits of approximately $2.00 per month associated with avoided GHG emissions from the manufacture of a new functional battery of same capacity (outlined in Section 3.2); and
- Benefits of approximately $5.00 per month associated with avoided GHG emissions and lithium metal losses from the smelting of the battery for recovery of cobalt if not repurposed (outlined in Section 3.3).

These benefits together total approximately $7.00 per month. As further discussed earlier, there are also likely to be further externality benefits, but not possible at this time to properly quantify. To put these benefits in context, a net comparison, including both economic and externality benefits, is presented in Table 13 for building-connected DCFC systems, but only considering four options:

- **Current B2U** DCFC system, based on the unit as constructed, connected to a building, and proven through demonstration to be fully operational and functional;
- **25-kW** DCFC grid-based system, connected to a building;
- **60-kW** DCFC grid-based system, connected to a building; and
- **120-kW** DCFC grid-based system, connected to a building.

Table 13. Externality Benefits for Building-Connected DCFC with 5% Utilization

DCFC Option	Total Cost	Externality Benefit	Net Benefit Current B2U	Externality Proportion
Current B2U	$524	$7	n/a	n/a
25-kW DCFC	$631	$0	$114	6.1%
60-kW DCFC	$2,634	$0	$2,117	0.3%
120-kW DCFC	$4,286	$0	$3,769	0.2%

As outlined in Table 13, calculated externality benefits contribute approximately 6.1% of the overall net benefit in the case of the most direct alternative, i.e., the 25-kW grid-based system. While externality benefits are not huge in this case, they are nevertheless relatively consequential. On the other hand, for much-higher power-level conventional grid-based systems, the estimated externality benefits are relatively trivial in comparison.

4.5 Further Site Locations for Extended Demonstration

The current location of the B2U DCFC at RRC Polytech itself is has been based primarily on technical requirements in order to confirm the ongoing operational suitability and usability of the system. Now that the technology appears to have comfortably achieved a readiness level of around TRL #8 (See Section 1.2), it would be desirable to consider further sites to better assess operational suitability, including for identification of further modifications or enhancements that may be worthwhile.

As discussed, the capacity of the system, most comparable to a 25-kW grid-based system, is most suitable for short-term charge top-ups within urban areas, rather than intercity highway operations, where a somewhat larger 50-kW or so grid-based system may be more suitable. This suggests urban locations involving: (i) relatively short duration stays (i.e., typically 1 to 2 hours); (ii) relatively unpredictable arrival patterns (i.e., not a regular workplace site, and likely not well-planned in advance); and (iii) relatively unpredictable but relatively significant charging needs (i.e., 10 to 20 kWh of charge required). Further, it would be important that such sites are not already well serviced by or accessible to existing charging sites.

Based on these requirements, two types of locations have been identified to consider for further operations:

1. **Tertiary-care hospital sites**. Winnipeg's main tertiary-care hospitals are Health Sciences Centre (HSC) and St. Boniface Hospital (St. B), located more centrally:
    - Neither facility is, currently, located in proximity to any convenient public-charging sites, with the two illustrated respectively in Figure 5 (HSC), and Figure 6 (St. B), based on information from ChargeHub (2022).
    - Both involve "destination" locations, with patients and visitors arriving for relatively short periods of a few hours, and with arrival patterns and charging needs relatively unpredictable. (Note a patient coming to the hospital for a relatively longer stay, and not arriving via an emergency vehicle, would involve a drop-off event with shorter parking duration too).
    - Various medical professionals are known to drive electric vehicles, however, the orientation in this case is to patients and visitors. For workplace charging, involving longer and more predictable arrival patterns and duration, the use of relatively low capital-cost Level 1 infrastructure is likely more suitable, and much more cost efficient.
    - Both hospitals also serve diverse populations involving a range of incomes, providing a degree of equity in location for such sites.
    - St. B in particular is currently about to undertake significant modifications to its Emergency Medicine facilities, offering a potential tie-in opportunity. As such, St. B is suggested as the priority target.

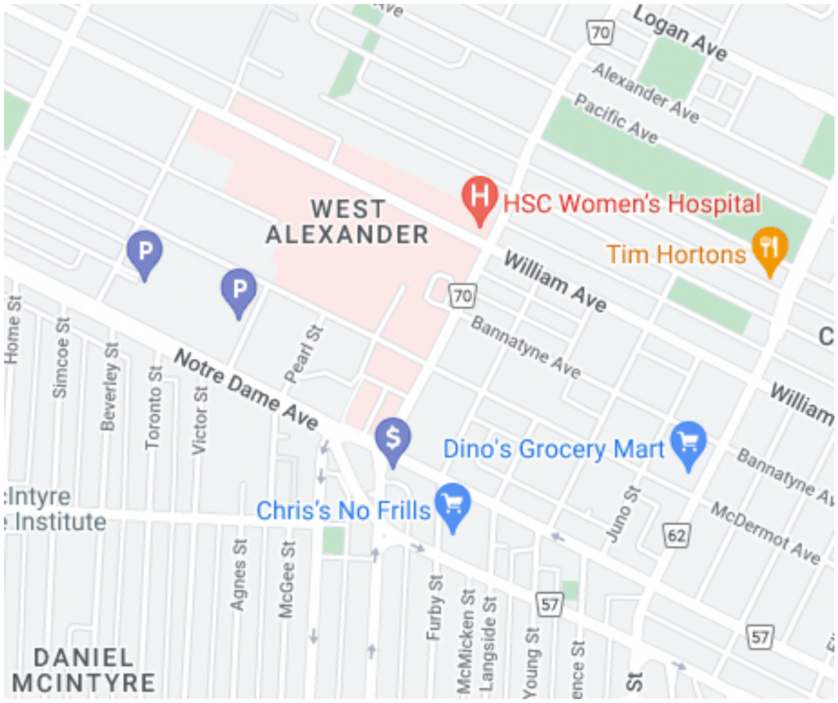

Figure 5. Vicinity of Health Sciences Centre, Winnipeg, showing a lack of existing charging facilities (ChargeHub 2022).

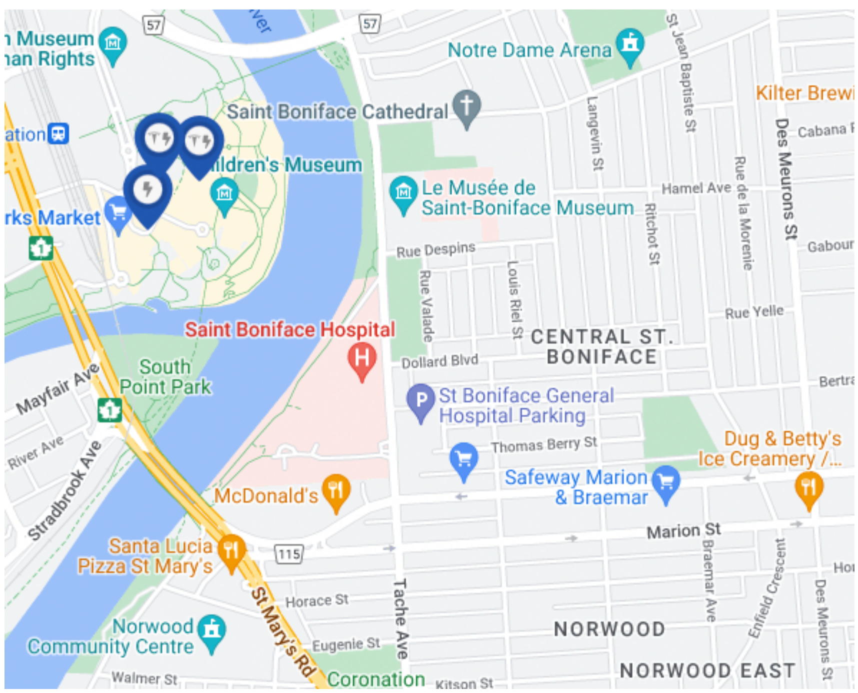

Figure 6. Vicinity of St. Boniface Hospital, Winnipeg, showing a lack of existing charging facilities (ChargeHub 2022).

(Note charging locations are present relatively near St. Boniface Hospital, but are all across the river, mostly near The Forks, and thus not practically relevant for the hospital).

2. **Big-box-mall retail store sites**. Some such sites already possess charging infrastructure, with the IKEA store complex off Kenaston Boulevard being a good example. Other sites, however, lack infrastructure, with one useful example target location being Costco Wholesale, with three possible sites in Winnipeg:
    - These businesses tend to be "destination" oriented, but located more toward the outer edges of the city.
    - Customers tend to be involved in more-extended shopping trips, with relatively larger volumes of goods purchases, and can easily spend at least one-hour at such stores.
    - At the same time, customers can also come more spontaneously.
    - Nature of stores and purchase volumes involved mean that customers would not tend to park at neighbouring sites for charging.

5.0 Conclusions and Recommendations

5.1 Conclusions

Through its B2U DCFC demonstration project, co-funded through NRCan (i.e., EVID #1022), RRC Polytech has successfully built and operated in Winnipeg a workable rapid-charging station for light-duty electric vehicles using already extensively-used batteries from electric transit buses. This cost-benefit analysis report has been prepared to support the demonstration, primarily to better characterize the nature and extent of the business case and avoided externalities, and to examine suitability of replication at additional sites. This project continues to build some relatively unique competencies within Manitoba on the evaluate of and use of already-used batteries. A number of significant findings emerge, some unexpected.

Findings regarding the operating characteristics of the B2U system include the following:

- Functional B2U system, in practical operations, can deliver about **23 kWh** of energy to electric vehicles within the charging time-limit of one-hour maximum.
- Energy delivery over this time corresponds to added travel distance for an electric vehicle in the range of about **110 to 130 km**.
- Given the deliberately lower recharging rate at 11 kW, the B2U system can provide **seven vehicle charges** over a **12-hour day**.
- The relative speed of charging and the added travel distance, as provided, suggest the B2U system is best suited for **urban areas**, acting primarily for **energy top-ups**, especially urgent situations when drivers encounter low states-of-charge.

- At the same time the current B2U system is likely somewhat **too small** for **inter-city highway** travel applications, where a higher-power level system in the range of 50 to 60 kW is likely more suitable.
- Energy delivery level for the B2U system actually **corresponds to mean charging** observed in current data from Europe for DCFC systems in general. Data further suggest the average utilization of DCFC systems is **only about 5%,** or just over once every two days, and with highly optimistic utilization level **being 10%**, or just-over once every day. Given this situation, the relatively slower recharging rate for batteries is not a practical hinderance.

Findings regarding the capital costs for the B2U system include the following:

- Capital costs for the functional B2U system are **comparable** to other more-conventional grid-based DCFC stations of similar size and capacity, and **lower** than battery-based systems employing new rather than used batteries.
- Relatively straightforward modifications have already been identified for future versions of a station, although not yet implemented, that could significantly simplify and reduce the capital costs for the B2U system by approximately **$12,500 or 35%**.
- Capital costs for the B2U system in this analysis include a value for the used-batteries, here based on the approximate current value of most-important minerals within the battery. Such an approach means that repurposing can translate to a (modest) net value "benefit" for used-battery provider (i.e., NFI Group in this case), rather than a net "cost" as would be more associated with disposal.

Findings regarding monthly-costs for the B2U system within Manitoba include the following:

- Within Manitoba, monthly costs associated with all types of DCFC systems are dominated primarily by costs to cover **capital**, secondarily by **demand fees**, and with electrical **energy fees** being relatively unimportant.
- Within Manitoba the function B2U system offers a significant savings in monthly-costs compared to grid-based systems, being about **17% lower** on a monthly basis, and also, given reduced capital costs, show lower costs than battery-based system employing new batteries, being about **20% lower** on a monthly basis.
- Savings compared to similar grid-based systems are primarily due to much lower demand fees.
- Within Manitoba, if a simplified version of the B2U system is considered, with monthly savings anticipated to increase to **37% lower** compared to grid-based systems on a monthly basis.

Findings regarding the monthly-costs for the B2U system when compared across Canadian jurisdictions include the following:

- Electrical utility demand fees and energy fees vary quite substantially across Canada, with demand fees being **crucial** in considering the economic viability of the B2U system, and with electrical energy fees being relatively **unimportant**.

- Jurisdictions having utilities with consistent and relatively-higher demand fees, such as Manitoba and Nova Scotia, show the **highest monthly saving** for the B2U system, indeed with Manitoba showing the best viability within Canada as a whole.
- Jurisdictions having utilities with consistent and relatively lower demand fees, such as BC, do show some **savings but much lower**, and thus much less attractive.
- Jurisdictions having utilities with variable demand fees, including New Brunswick, Saskatchewan and Quebec, with these also typically involving some threshold level below which demand fees are not levied, represent the **least beneficial applications** for the B2U system, with some provinces, such as Saskatchewan and Quebec, even showing the B2U system to have appreciably higher monthly-costs than a grid-based system.
- Careful evaluations of the details of demand fees structures in individual provinces are needed in confirming whether or not, and to what extent the B2U system could offer potential benefits.

Findings regarding externality benefits of the B2U system include the following:

- Various externality benefits can be identified as relevant to consider for the B2U system, however, not all can be readily **monetized** at this time. Two specific externality benefits can be monetized in this case and are identified.
- First involves benefits associated with avoided GHG emissions from the **manufacture of a new functional battery** of the same capacity.
- Second involves benefits associated with avoided GHG emissions and lithium metal losses from the **smelting** of the battery for recovery of cobalt if not repurposed.
- Of these two, the second is the largest but both combined are still not large, on a monthly-basis representing only about **$7.00**. While relatively small, this is notable when considering the 25-kW grid-based station, for which externality benefits amount to approximately **6%** of savings per month.

Findings regarding follow-up locations for further demonstration include the following:

- Further monitoring of the B2U system will continue at RRC Polytech in order to provide solid evidence of the utility and practical functionality of the current system.
- Additional demonstration of the B2U system is desirable to better assess operational suitability in somewhat differing applications, including for identification of further modifications or enhancements that may be worthwhile in each case.
- Two specific follow-up demonstration applications within Winnipeg have been identified: **tertiary-care hospitals**, with St. Boniface Hospital specifically identified as a target site: and **big-box mall retail store** sites.

5.2 Recommendations

RRC Polytech's current priority is to complete remaining monitoring activities for the B2U system over the remaining period of the project. This is in order to better confirm the system's technical functionality and suitability over multiple years of operation, and to fulfill commitments to NRCan as part of funding responsibilities.

Moving forward into the future, a variety of recommendations emerge from this work, including the following, whereby RRC Polytech should:

- Maintain the existing B2U system in place operationally for an extended period after formal project completion, i.e., for as long as may be reasonable, in order to maximize value, profile and relevant data from the system. This includes, if possible, much longer operation to physically confirm the lifespan of the repurposed batteries.

- At the same time, consider further options for the existing B2U system, in particular alternative sites to better assess operational suitability for other types of locations (including identifying additional modifications or enhancements that may be worthwhile for such installations). Two types of locations are identified for this purpose: tertiary-care hospitals, with St. Boniface Hospital specifically identified; and big-box-mall retail store sites. Also note that moving the system but maintaining it in operation would still permit assessing physical lifespan of repurposed batteries.

- Consider pursuing the assembly and implementation of an upgraded version of the B2U system, as long as suitable funding can be located, involving the lower-cost simplifications as outlined, this in order to confirm operational functionality, and further associated economic advantages.

- Continue discussions with NFI Group regarding availability and repurposing of further used BEB batteries, and how such arrangements could transition over the longer term into a business solution for NFI that can provide them sustained competitive advantage in the transit bus manufacturing industry. Importantly, as noted, a value for the used-batteries is included in the analysis, in this case based on current values of the main minerals (cobalt and lithium). Further discussions are important to better define a suitable reimbursable value for such batteries. This is to ensure that a clear business case exists for repurposing, one that also could provide NFI a sustainable competitive advantage.

- Emphasize growth in local expertise and competency in the unique niche area of battery repurposing, including building towards possible development of a mini-industrial-cluster, and emphasize RRC Polytech's increasing prominence in this field, in particular as a central organization for any mini-industrial-cluster. Additional supporting partners could include Manitoba Hydro International, based on significant past work, and the University of Manitoba.

- Begin to identify and explore pathways for more-commercial application of the B2U technology, possibly including some sort of start-up company or industrial partner. Some collaboration with the University of Manitoba in this regard may be useful.

- Initiate discussions with further vehicle manufacturers, in particular heavy-duty vehicle manufacturers, regarding access to additional types of already-used heavy-duty electric vehicle batteries.

- Given RRC Polytech's recent leadership and increased profile on regional-wide electric vehicle charging infrastructure enhancement (Cash 2022), begin working with neighbouring provinces and associated collaborators for logical follow-on work with the B2U systems, i.e., Saskatchewan Polytechnic in Saskatchewan, and Northern Alberta Institute of Technology (NAIT) in Alberta.

- In particular, explore more-detailed assessments with collaborating institutions to clarify potential value of the B2U system in their jurisdictions. Based on preliminary information as outlined in this analysis, Saskatchewan may be less suitable for the B2U system, given utility demand fee structures in that province, while Alberta is less straightforward, given utility fees there tend to be more complex. Hence, more detailed analysis is worthwhile in both cases.

- Given both the potentially large scale of the Ontario market, but also some-what more-complex utility rate structures there, explore work with collaborators or partners in Ontario to better understand the business case for and the viability of the B2U system in that jurisdiction. This direction is also predicated on the preliminary finding that two other large Canadian jurisdictions that are prominent in electric vehicles, namely Quebec and BC, appear to show poor economic viability for the B2U system. Understanding potential in Ontario is thus important.

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